BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

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

Exhibit 76
Secretary Wright's West Virginia Remarks

https://www.wvnews.com/news/wvnews/energy-secretary-chris-wright-future-of-u-s-coal-is-long-and-bright/article_948eb88e-2509-42a3-b985-07c47f1ee151.html

TOP STORY

Energy Secretary Chris Wright: Future of U.S. coal Is 'long and bright'

by Charles Young SENIOR STAFF WRITER
Jul 5, 2025

1 of 2



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Some coal-fired facilities have been closed before the end of their useful lives, said U.S. Energy Secretary Chris Wright Morgantown.

Staff photo by Charles Young

MORGANTOWN (WV News) — “The future for coal is long and bright,” said U.S. Energy Secretary



Wright, while visiting the National Energy Technology Laboratory facility, said the Trump administration wants to work to reverse the industry's decades of decline by encouraging greater production and use of coal, along with preventing the premature closure of still-viable coal-fired power plants.

The administration views coal as a valuable asset needed to gain an economic edge over China, especially when it comes to AI, Wright said.

"We're going to need 50 to maybe 150 gigawatts of new capacity, and if you're going to add a lot of new capacity, the first thing you should do is stop shrinking the capacity you have," he said.

Wright calls the need to increase the nation's electrical capacity the "second Manhattan Project," in reference to the program that created the first atomic weapons.

"AI is the second parallel — a huge innovation where we can't get second," he said. "China put on about 90 new coal plants last year, and about a similar amount of new plants will come on this year. They've rapidly grown their electricity for industrial processes, also for AI."

Recommissioning a retired coal-fired facility is a difficult process, but his team plans to look into the possibility of bringing some closed plants back online, Wright said.

"We're looking at that, and I think you will see some coal plants reopened," he said.

Meanwhile, his department will work to prevent the imminent closure of facilities throughout the country, Wright said.

"I think our biggest impact by far is going to be — there are like 40 coal plants that are supposed to close this year — and our biggest impact is going to be to stop the closure of most of those," he said.

As U.S. energy secretary, he has the authority to prevent the planned closure of some power plants, Wright said.

"It's been very politically fashionable to close, really for the last 15 or 20 years, coal power

West Virginia has a long history of energy production, dating back more than a century, Wright said.

“West Virginia has been an energy industrial powerhouse since it has been a state,” he said. “I think the outlook in energy and industry is quite bright.”

In April, Trump signed a series of executive orders to reinvigorate the “Beautiful Clean Coal Industry,” prevent regulatory overreach by state governments, and strengthen the reliability of the national electric grid.

“These executive orders are a direct investment in America’s energy future and in the communities that have long powered our nation,” Trump said during the event.

The orders mark a major shift for the industry, according to Coal Association President Chris Hamilton.

“We are deeply grateful to President Trump, Energy Secretary Wright, Secretary [Doug] Burgum, and EPA Administrator Lee Zeldin for their leadership in rolling back these anti-coal regulations,” he said. “For years, our industry has faced undue pressure from excessive regulatory measures that have led to job loss and stifled industry growth and innovation.”

Sen. Shelley Moore Capito, R-W.Va., recently said the administration’s efforts to support the coal industry will “keep our coal miners working and our coal facilities open, I think will increase employment just because of increased production but also the increased use of coal.”



Hamilton

However, it’s unlikely any new coal-fired power plants will be built any time soon, Capito said.

“You and I both know that’s a pretty steep hill to climb,” she said. “There have been no new coal

The Longview Power Plant in Monongalia County, near Maidsville, went into operation in 2011.



Capito



The Longview Power Plant in Monongalia County, near Maidsville, went into operation in 2011.
Staff file photo by Charles Young

The president's plan instead calls for the industry to "modernize what we have," Capito said.

"So that we can run them through their entire life and then keep that employment very robust," she said.

There are nine coal-fired electrical generation facilities in West Virginia: Pleasants Power Station, Harrison Power Station, Mountaineer Power, John Amos, Mount Storm, Morgantown Energy Associates, Longview Power, Fort Martin Power Station and Mitchell Power.

West Virginia is the second-largest coal producer in the nation, after Wyoming, and accounts

West Virginia has 16% of U.S. recoverable coal reserves, the third-largest state reserves after Wyoming and Illinois.

In 2023, coal-fired power plants accounted for 86% of West Virginia's total electricity net generation. Renewable energy resources, primarily wind energy and hydroelectric power, contributed 7%, and natural gas also provided about 7%.

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Public Interest Organizations

Exhibit 77
MISO 2021 Transmittal Letter

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November 30, 2021

VIA ELECTRONIC FILING

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: Midcontinent Independent System Operator, Inc.'s Filing to Include Seasonal and Accreditation Requirements for the MISO Resource Adequacy Construct Docket No. ER22-____-000

Dear Secretary Bose:

The Midcontinent Independent System Operator, Inc. ("MISO"), through this filing, proposes revisions to its Open Access Transmission, Energy and Operating Reserve Markets Tariff ("Tariff")[1] to establish Resource Adequacy Requirements on a seasonal basis for each of the Summer, Fall, Winter and Spring Seasons, and to implement an availability-based Seasonal Accredited Capacity ("SAC") methodology for resources participating in MISO's annual Planning Resource Auction ("PRA"). As discussed in detail below, Commission action is needed at this time in order to ensure that MISO has in place the proposed enhancements to its Resource Adequacy construct necessary to address the growing risks to reliability in the MISO Region resulting from a changing resource mix and shrinking excess reserve margins. Moreover, the recommendations from the Federal Energy Regulatory Commission ("FERC") and the North American Electric Reliability Corporation ("NERC") Final Report,[2] as well as MISO's internal report,[3] following the February 2021 Winter event reinforces the need for and urgency of the proposed reforms to the Resource Adequacy construct. Ultimately, MISO's proposal will help ensure Planning Resources are available to convert capacity procured in the PRA to energy when and where they are most needed.

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1 MISO submits these amendments pursuant to section 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d, and section 35.12 of the Federal Energy Commission's ("FERC" or "Commission") regulations, 18 C.F.R. § 35.12 (2018). All capitalized terms in this filing not otherwise defined have the same meaning as they have under the current MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff ("Tariff").

2 *See* FERC, Final Report on February 2021 Freeze Underscores Winterization Recommendations November 16, 2021 (November 2021) ("FERC Final Report"), available at: https://www.ferc.gov/news-events/news/final-report-february-2021-freeze-underscores-winterization-recommendations.

3 *See* https://cdn.misoenergy.org/2021%20Arctic%20Event%20Report554429.pdf ("MISO Arctic Report").

In order to accommodate the implementation of this proposal in advance of the 2023 / 2024 Planning Year, MISO requests the Commission issue an order on this proposal within 120-days of this filing granting an effective date of September 1, 2022 for the proposed revisions. The requested timeline for acceptance and implementation of the instant proposal will accommodate all necessary stakeholder and MISO actions well in advance of the initial PRA in the Spring of 2023. Commission action within the requested 120-day period also is needed to help ensure MISO has adequate time to implement the changes to its software and systems prior to the 2023 / 2024 PRA, and to help guide decisions and investments that resource owners should be making to improve their accreditation under the proposed construct. Importantly, the software and system changes necessary to implement this proposal are not dependent upon MISO's ongoing Market System Enhancement initiative.

I. EXECUTIVE SUMMARY

The MISO Region is experiencing significant shifts in generation resource retirement, increased reliance on intermittent resources, significant weather events with correlated generator outages, and declining excess reserve margins. To highlight the priority and urgency of this transformation, the North American Electric Reliability Corporation ("NERC") in its Long-Term Reliability Assessment report recently stated:

> The addition of variable energy resources, primarily wind and solar, and the retirement of conventional generation is fundamentally changing how the [Bulk Power System] is planned and operated. Resource planners must consider greater uncertainty across the resource fleet as well as uncertainty in electricity demand that is increasingly being effected [*sic*] by demand-side resources. As a result, reserve margins and capacity-based estimates can give a false sense of comfort and need to be supplemented with energy adequacy assessments.[4]

In the Reliability Assessment, NERC also stated, "To ensure reliability during the transition to greater reliance on wind and solar resources, emerging resource and energy adequacy issues must be addressed. Planning for long-term Resource Adequacy is becoming increasingly complex with a resource mix that is more unpredictable and less energy-assured."[5] To address these issues, NERC recommended that: "Regulators and policy makers should consider revising their resource adequacy requirements to consider new risks that emerge during non-peak hours, limitations from neighboring systems during system-wide events, and the reduced resource diversity and/or increased reliance on a single fuel source or delivery mode."[6] Pointedly, FERC and NERC have also recently made recommendations in light of the extensive resource outages of the February 2021 Winter event. These recommendations support both improved seasonal risk

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4 NERC, 2020 Long Term Reliability Assessment (LTRA), at 6 (Dec. 2020), ("NERC Reliability Assessment") available at: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2020.pdf (NERC 2020 LTRA).

5 *Id.* at 7.

6 *Id.*

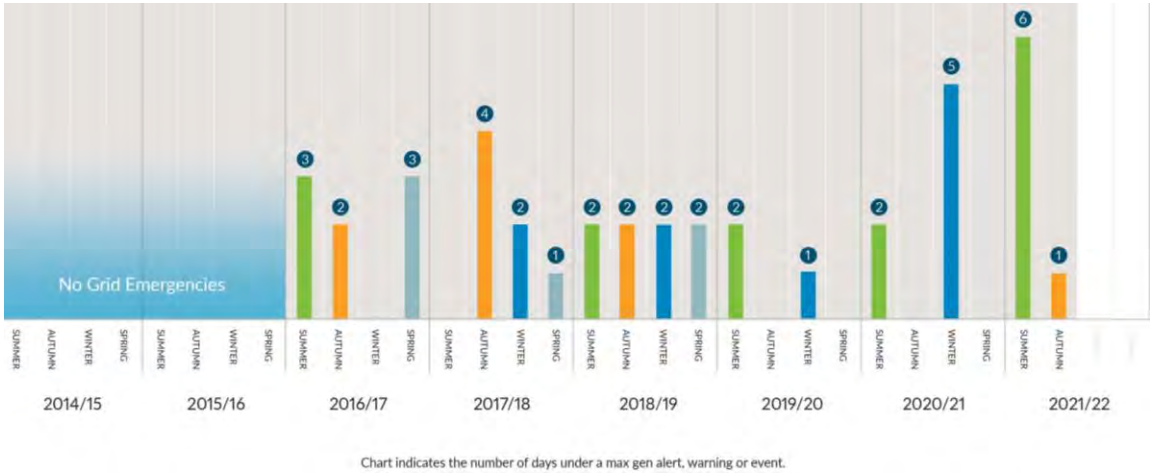
assessments and the stronger alignment between accreditation and expectations of availability during times of highest need.[7]

MISO agrees with these statements and as discussed in the testimony of Mr. Wright, MISO's Executive Director of Market Development and Design, these shifts, coupled with lower excess reserve margins, increases in extreme weather events, correlated generator outages, and emergency operations, will have a profound impact on the reliability of the grid in the coming years.[8] Ultimately, all industry participants have a shared responsibility to plan for these impacts and implement new policies and practices to ensure the continued reliability of the grid. MISO refers to this shared responsibility as the "Reliability Imperative." As part of its response to the Reliability Imperative, MISO must make substantive changes to its Resource Adequacy construct to address these emerging issues as the transition accelerates in the coming years.

MISO's response to the Reliability Imperative is being accomplished through a number of initiatives that work in concert to mitigate the challenges facing the MISO Region. MISO organizes this work into four major categories: (1) Market Redefinition; (2) Long Range Transmission Planning; (3) Operations of the Future; and, (4) Market Systems Enhancements.

Through Market Redefinition, MISO aims to ensure that sufficient resources with the capabilities and attributes the MISO Region needs will be available during the highest risk periods across the year. MISO's current Resource Adequacy construct, which focuses on the procurement of capacity for an entire Planning Year to meet demand during one peak day of the Summer Season was not designed to address the trends currently facing the MISO Region.

Reliability risks associated with Resource Adequacy have shifted from "Summer only" to a year-round concern. Since 2016 MISO has experienced 40 Maximum Generation declarations (including alerts, warnings and events) ("MaxGens") with more than 60% occurring outside of the Summer months, as evidenced in the graph below.



7 *See* FERC Final Report at 6.

8 Wright at 11.

MaxGens are governed by MISO's emergency operations procedures and include a number of emergency actions, up to and including shedding firm load. Consistent with NERC's Reliability Assessment, the significant increase in MaxGens is being driven by the confluence of: the retirement of traditional, baseload generation resources; planned and forced generator outages in non-Summer months; an increased reliance on intermittent generation such as wind and solar, which has reached nearly 30 percent of the generation resource mix in certain portions of the MISO Region and is projected to continue to grow; and, extreme weather events resulting in numerous forced generator outages, including multiple polar vortex and arctic storms reaching south to the Gulf of Mexico.

The causes of the increase in MaxGens cannot be addressed through one-off, quick fixes; rather, they require a robust solution that incentivizes capacity resources to be available when and where they are needed. Ultimately, the existence of resources, even if ample in quantity and well-located, is meaningless if those resources do not provide energy or reserves when needed. MISO cannot reliably operate the system if the resources it depends on do not or cannot perform — that is, do not provide energy or reserves as offered during periods of highest risk. A well-designed market construct is inclusive of both the planning horizon and the operating horizon. The planning horizon includes the identification and incorporation of risks across the year in Resource Adequacy Requirements. The operating horizon ensures that those resources are appropriately incentivized to provide the energy and reserves when and where needed. More closely aligning the planning horizon with the operating horizon is a central goal of the proposed reforms in the instant filing.[9]

To address these critical issues, MISO's Resource Adequacy reform proposals focus on related areas including: the establishment of a seasonal Resource Adequacy construct coupled with availability-based accreditation for certain Planning Resources; and, a Minimum Capacity Obligation that promotes securing capacity well in advance of the Planning Resource Auction. The instant filing presents MISO's Seasonal and Accreditation proposal.

A. Seasonal Resource Adequacy Construct

MISO intends to transition from the current Summer-based, annual construct to four distinct Seasons: June to August for Summer, September to November for Fall, December to February for Winter, and March to May for Spring. Under the proposed construct MISO will establish Planning Reserve Margin Requirements ("PRMR") for all Market Participants ("MPs") representing Load Serving Entities ("LSEs") on a seasonal basis. MISO will then conduct the PRA and establish an Auction Clearing Price for each Local Resource Zone ("LRZ") for each Season. The PRA will still be conducted one time per year, in the Spring before the applicable Planning Year, but will clear the requirements for each Season.

Overall, the shift to a seasonal construct is expected to further mitigate Resource Adequacy risks across the year, not just in the peak Summer Season, by establishing more granular, seasonal Resource Adequacy Requirements to help ensure sufficient resources are committed and obligated to be available when needed. Expected outcomes from this transition are to: (1) identify reliability

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[9] Wright at 14.

needs unique to each Season; (2) align resource availability with seasonal needs; and (3) facilitate and better account for seasonal outages or partial year operations.

B. Availability-Based Resource Accreditation

MISO's Resource accreditation reforms seek to assure that Resources are available when needed the most by aligning Resource accreditation with availability during the highest risk periods in each Season. To accomplish this in a seasonal construct, MISO proposes to determine the Seasonal Accredited Capacity ("SAC") for certain classes of Resources. MISO also proposes a tiered weighting structure, with a transition period, to determine individual resource accreditation by Season based on each resource's real-time offered availability, accounting for coordinated planned outages.

The expected outcomes of MISO's efforts are to: (1) increase confidence in the capacity MISO can count upon when needed by shrinking the gap between cleared capacity within the PRA and realized capacity during tight conditions; (2) provide improved signals for availability and coordination; and (3) improve outage coordination processes. Measuring and accrediting Planning Resources based on availability and performance during Resource Adequacy Hours (or "RA Hours"), as described in the testimony of Mr. Wright, will better align expectations during times of highest need. Actual historic Resource availability and performance during times of highest need is a useful and reasonable indicator of what to expect in the future. Relying on installed capacity, adjusted for forced outages and reflecting average availability throughout the year, no longer provides an accurate expectation of availability, as proven by recent emergency events, especially those driven by extreme weather.

II. BACKGROUND

This filing is a component of the next phase of MISO's ongoing Resource Availability and Need ("RAN") initiative. The factors giving rise to the need for MISO to explore various short- and longer-term RAN initiatives, and related Tariff enhancements, have by now been well-documented, including a series of MISO-published White Papers dating back to March 2018,[10] as well as MISO's prior RAN filings and related Commission Orders. As described in those documents, MISO established its RAN initiative to identify strategies to better convert committed Planning Resources into energy during times of need.[11] MISO submits this filing to establish the design for additional Resource Adequacy reforms, including a Seasonal Resource Adequacy Construct, Availability-Based Accreditation, and Seasonal Planning Resource Auctions. MISO is

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[10] *See* Resource Availability and Need, *Issues Statement Whitepaper*, March 30, 2018; Load Modifying Resources, *Capacity Instruments affecting Resource Availability and Need*, May 25, 2018; Resource Availability and Need, *Evaluation Whitepaper*, September 10, 2018; Aligning Resource Availability and Need, December 2019, MISO Forward, March 2019, and MISO Forward 2020, *Utilities of the Future: What do they need from a grid operator?*, March 2020. *See generally* Resource Availability and Need (RAN) (IR025). Available at https://www.misoenergy.org/stakeholder-engagement/issue-tracking/resource-availability-and-need-ran/

[11] *See* Aligning Resource Availability and Need, December 2019, MISO, pp. 2-3. Available at https://cdn.misoenergy.org/Aligning%20Resource%20Availability%20and%20Need%20(RAN)410587.pdf

making a concurrent filing related to the establishment of a new Minimum Capacity Obligation. The details of this additional reform will be addressed in the concurrent filing.

MISO is facing a Reliability Imperative during this period of unprecedented change. While MISO and its stakeholders have successfully managed reliability there has been a significant increase in the number of MaxGens occurring outside of the traditional Summer peak months. These changes have prompted MISO to evaluate the alignment of resource availability and need to determine how today's processes can be improved to ensure the reliable and efficient conversion of procured capacity to energy throughout the year.[12] This process has become increasingly uncertain as a result of a dramatically changing landscape and factors such as retiring and aging generation units, lower overall capacity levels and higher outage rates, growth in demand-side and other emergency-only capacity as a percent of the portfolio, growing reliance on unscheduled resources (notably non-firm imports), and the growth of intermittent energy resources as a percentage of the fleet.[13]

MISO has proactively engaged with stakeholders and developed its RAN initiative to mitigate these and other challenges. The RAN program initially identified four goals: (1) Improve outage scheduling and expectations; (2) Link Resource accreditation and requirements with initial focus on Load Modifying Resources ("LMRs"); (3) Align the PRA resource commitments with energy needs all year; and (4) Ensure flexible Resource availability to address changing fleet characteristics. Each goal corresponds to a group of potential solutions discussed with stakeholders that address related gaps, such as a lack of transparency in outage scheduling or limited access to LMRs.

To achieve these goals, MISO proposed and implemented several incremental changes, each of which was intended to improve reliability within the MISO Region. These changes are known as MISO's RAN Phase I initiative, and are outlined below:

- MISO's first RAN Phase I filing was submitted on December 21, 2018. There, MISO filed proposed revisions to its Tariff to more effectively assess the capabilities of LMRs.[14] MISO proposed to require an LMR to (1) offer its capability based on its actual availability in all Seasons, including maintaining the current requirement that LMRs be available for the entire Summer Season, and (2) deploy based on the shortest notification requirement that it can consistently meet, while maintaining that LMRs must be available in less than 12 hours.[15] MISO also proposed Tariff revisions that would allow it to issue Scheduling Instructions to LMRs in advance of anticipated Emergency

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12 *See* Resource Availability and Need, *Issues Statement Whitepaper*, March 30, 2018, at pp. 2-3. Available at https://cdn.misoenergy.org/20180405%20RSC%20Item%2007%20RAN%20Issues%20Statement%20White%20Paper164746.pdf

13 *Id.*

14 *Midcontinent Indep. System Operator, Inc.*, 166 FERC ¶ 61,116 (Feb. 19, 2019).

15 *Id.*

conditions.[16] The Commission accepted those revisions subject to certain revisions in an order dated February 19, 2019.[17]

- MISO's second RAN Phase I filing was also submitted on December 21, 2018. There, MISO filed proposed revisions to its Tariff to enhance the testing requirements for Demand Resources that participate in MISO's markets as LMRs.[18] Additionally, MISO proposed to revise its Tariff to require all Demand Resources to conduct a real power test annually, starting with qualification for the 2020/21 Planning Year.[19] MISO also set forth certain proposed waiver and opt-out provisions.[20] The Commission accepted those revisions subject to certain revisions in an order dated March 29, 2019.[21]

- On January 30, 2019, MISO filed proposed revisions to its Tariff to enhance Generator Planned Outage scheduling.[22] These proposed incremental changes were intended to supplement MISO's then-existing Generator Planned Outage process by improving transparency through forward signals and incentives.[23] The Commission accepted those revisions subject to certain revisions in an order dated March 29, 2019.[24]

- On March 18, 2019—in compliance with the Commission's prior February 19, 2019 Order—MISO filed a request to revise its Tariff provisions regarding MISO's advanced access of the capabilities of LMRs, as previously directed by the Commission.[25] The Commission accepted MISO's submittal, as requested, in an entry dated April 29, 2019.[26]

As recognized by FERC and NERC, MISO's first RAN Phase I filing constituted "a broad analysis and plan to confront the increase in Maximum Generation emergencies even though sufficient capacity appeared to be available through the Planning Reserve Auction."[27] "Some of

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16 *Id*.

17 *Id*.

18 *Midcontinent Indep. System Operator, Inc*., 166 FERC ¶ 61,235 (Mar. 29, 2019).

19 *Id*.

20 *Id*.

21 *Id*.

22 *Midcontinent Indep. System Operator, Inc*., 166 FERC ¶ 61,236 (Mar. 29, 2019).

23 *Id*.

24 *Id*.

25 April 29, 2019 Letter to J. Krouse, Docket No. ER-19-650-001 (Apr. 29, 2019).

26 *Id*.

27 *See* The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018, 2019 FERC and NERC Staff Report, at p. 75, fn 101.

the early fruits of the initiative [have been] tariff changes to better insure capacity availability[.]"[28] "MISO's revisions, which included a penalty for planned outages and derates that occur during Max Generation events, were intended to: (1) provide additional incentives for Generator Owners to schedule Generator Planned Outages and derates well in advance of the scheduled start time and (2) identify times with increased system risk due to correlation of outages and derates."[29] "The Commission agreed with MISO's efforts, believing that MISO's proposal [would] 'promote advanced scheduling of Generator Planned Outages, improve Generator Planned Outage coordination, and help MISO address the recent increase in the number of declared Emergency events during non-summer seasons.'"[30]

Following the initial RAN Phase I filings, MISO made a number of additional RAN-related filings with the Commission, including the following:

- On May 18, 2020 MISO filed to enhance the LMR accreditation provisions of the Tariff to ensure LMRs are appropriately accredited for their participation in the PRA based on the LMRs actual availability and notification times. The Commission accepted this proposal on August 14, 2020 and the enhanced LMR accreditation were implemented on August 16, 2020.[31]

- On December 21, 2020 MISO submitted a filing to clarify the LMRs that are chosen to be deployed by Market Participants in response to MISO's Scheduling Instructions will be evaluated on an individual resource basis, rather than in aggregate across a Market Participant's portfolio of LMRs. The Commission accepted this clarification by letter order on February 3, 2021.[32]

- On January 30, 2019, MISO filed with the Commission a proposal to enhance Generator Planned Outage scheduling. MISO explained in this filing that the proposed revisions were necessary due in part to base load generation retirements that were contributing to the MISO Region operating with actual capacity margins that were approaching its minimum Planning Reserve Margin Requirements. MISO explained in that filing that operating at or near its minimum Planning Reserve Market Requirements exposed the MISO Region to greater impacts from correlated risks, such as extreme weather events and natural gas availability. The Commission accepted this filing on March 29, 2019.[33]

- On October 16, 2019, MISO submitted a filing to limit the ability of resources to participate in the PRA if the resource is expected to be on full or partial outage for any ninety (90) or

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28 *Id*. at p. 77.

29 *Id*.

30 *Id*., citing *Midcontinent Indep. System Operator, Inc*., 166 FERC ¶ 61,236 (Mar. 29, 2019) at P. 60.

31 *See Midcontinent Independent System Operator, Inc.,* 172 FERC ¶ 61,138 (August 14, 2020).

32 February 3, 2021 Letter to J. Krouse, Docket No. ER21-693-000 (February 3, 2021).

33 *See Midcontinent Independent System Operator, Inc.*, 166 FERC ¶ 61,236 (March 29, 2019).

more of the first one hundred twenty (120) Calendar Days in the Planning Year. The Commission accepted this filing on January 30, 2020.[34]

- MISO has also submitted reforms related to the deliverability of both conventional and intermittent resources. On October 27, 2020 the Commission accepted MISO's proposal to require conventional (*i.e.,* non-intermittent) Capacity Resources to demonstrate deliverability through Energy Resource Interconnection Service ("ERIS") coupled with firm Transmission Service up to the Capacity Resource's Installed Capacity level in order to be eligible to convert the entire Unforced Capacity of the Resource to ZRCs.[35] In addition, on November 13, 2020 the Commission accepted MISO's proposal to implement a long-term deliverability requirement for Intermittent Capacity Resources, including a methodology to determine the level of firm Transmission Service needed to convert Unforced Capacity into ZRCs.[36]

The proposed Resource Adequacy construct reforms also align with MISO IMM recommendations dating back to 2014. The IMM first recommended a transition to seasonal capacity procurement in its 2014 State of the Market Report.[37] In recommendation 2014-5 the IMM noted that the system and available system supply change substantially from one season to the next, which could be recognized by clearing the PRA on a seasonal basis rather than an annual basis.[38] The IMM also suggested that the shift to a seasonal PRA construct would produce benefits including: better alignment of revenues with the value of capacity; opportunities for high-cost resources to achieve savings by taking seasonal outages during shoulder seasons; and, more flexible mid-year retirements for resources without having to procure significant capacity to satisfy post-retirement capacity obligations.[39]

In the 2018 State of the Market Report, MISO's IMM noted that MISO's January 2019 filing to reduce the accreditation of resources taking short-notice outages during emergency conditions was a slight improvement but recommended that MISO file with FERC a more complete accreditation solution that would: a) expand the Generator Planned Outage scheduling enhancements filed in January 2019 to include all unforced and unreported outages and debates; and b) calculate the accreditation based on outages and derates that occur during the tightest supply conditions.[40] The IMM suggested that these changes would result in sizable accreditation

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34 *See Midcontinent Independent System Operator, Inc.* (Docket No. ER20-129-000)*; Wolverine Power Supply Cooperative, Inc. v. Midcontinent Independent System Operator, Inc.* (Docket No. ER19-102-000) (Not Consolidated), 170 FERC ¶ 61,066 (January 20, 2020).

35 *See Midcontinent Independent System Operator, Inc.* 173 FERC ¶ 61,095 (October 27, 2020).

36 *See Midcontinent Independent System Operator, Inc.* 173 FERC ¶ 61,139 (November 13, 2020).

37 2014 State of the Market Report for the MISO Electricity Markets Prepared by Potomac Economics (June 2015) at 99-100.

38 *Id.*

39 *Id.*

40 2018 State of the Market Report for the MISO Electricity Markets Prepared by Potomac Economics (June 2019) at 110-111.

improvements and eliminate the current incentive for suppliers to not report their outages and derates. Ultimately, the IMM argues that adopting the proposed accreditation reform would better represent the reliability value that resources provide to MISO (in periods when the resources are needed) and can be easily adapted to a seasonal capacity accreditation construct.[41]

While the changes implemented through MISO's RAN Phase I initiative and subsequent RAN-related filings have been helpful, MISO continues to face a Reliability Imperative and correspondingly needs to implement further reforms to its Resource Adequacy construct. MISO was clear that the RAN Phase I filings were the initial step in addressing specific issues in the Resource Adequacy construct and that more comprehensive solutions were being developed to address Resource Adequacy in the MISO Region. As such, the proposed Resource Adequacy reforms, submitted in this filing, better align accreditation with observed Resource availability during the periods of highest risk.

While true across all Seasons of the year, MISO has experienced notable reliability challenges during the Winter Season.[42] Consistent with Key Recommendation 2 in NERC's recent "Cold Weather Report," MISO's proposal would give Generator Owners accreditation values that align with the reliability benefits of winterization and Winter preparedness. These measures will enable Resources to operate in the temperature and weather conditions that have occurred during times of need during recent Winters.

In line with the guiding principles of the RAN initiative and the response to the Reliability Imperative, MISO's proposal will create better availability, flexibility, and visibility of resources to meet MISO's changing system needs including the need to address generator reliability for extreme cold weather. Seasonal requirements, including seasonal auctions, will ensure MISO's Resource Adequacy Requirements reflect reliability needs and required capabilities across the year. Accreditation reforms will ensure resources committed during the seasonal Planning Resource Auction receive accreditation based on their reliability contribution during the times of highest need. The proposed availability based seasonal construct will award more relative accreditation to resources that have properly mitigated risks during all Seasons.

III. SEASONAL RESOURCE ADEQUACY CONSTRUCT

A. Establishment of Seasonal Resource Adequacy Requirements

MISO proposes continuing its Resource Adequacy reform efforts – in part – by establishing seasonal Resource Adequacy Requirements. MISO intends to transition from its current annual construct, which focuses on the historic Summer peak period, to a seasonal construct with four distinct Seasons: (1) Summer (June to August); (2) Fall (September to November); (3) Winter (December to February); and (4) Spring (March to May).[43] Under the proposed seasonal Resource

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41 *Id.*

42 MISO Arctic Event at 5, 7.

43 Wright at 26.

Adequacy construct, MISO will perform an LOLE evaluation to establish PRMRs for all Market Participants representing LSEs[44] and Local Clearing Requirements ("LCR") for all LRZs on a seasonal basis.[45] MISO will then conduct the Planning Resource Auction and establish an Auction Clearing Price for each LRZ for each Season.[46] The Planning Resource Auction will continue to be conducted once per year, in the Spring preceding the applicable Planning Year, but the PRA will clear the requirements separately for each Season.[47]

As explained by Mr. Wright, this shift to a seasonal Resource Adequacy construct is designed to ensure that resources with needed capabilities and attributes will be available during the highest risk periods across the year.[48] Under the current construct, the requirements of the annual PRA are based on Summer Coincident Peak Demand forecasts, and transmission capability and most Resource accreditation is also based on Summer conditions.[49] As a result, actual needs outside the Summer Season are not explicitly determined and defined, leaving potential risks unmitigated.[50] Such risks are intensifying as indicated by the increased incidence of MaxGens occurring in the Seasons outside of the traditional Summer peak.[51] Moreover, sizeable segments of dispatchable thermal generation are aging with correlated increased outage rates, and MISO's resource portfolio is shifting to increasing amounts of intermittent and highly weather-dependent wind and solar resources, all against a backdrop of lower excess reserve margins.[52] In his testimony, Mr. Smith notes that the trends and generation resource fleet transition driving the challenges to reliable market operations are only expected to accelerate, leading to further reduced operating margins.[53] Moving to a seasonal Resource Adequacy construct will align seasonal resource accreditation with seasonal resource availability to meet this changing risk.[54]

MISO proposes several changes to implement the seasonal Resource Adequacy construct, including accrediting resources by Season based on their availability during times of need and developing seasonal values for several construct parameters such as: (1) LOLE sub-annual modeling; (2) PRMRs; (3) Local Reliability Requirements ("LRR") and LCRs; and (4) Capacity

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44 As used throughout this transmittal letter, references to LSE is intended to also include Market Participants representing LSEs.

45 Wright at 26.

46 *Id*.

47 *Id*.

48 Wright at 13.

49 Smith at 18.

50 *Id*. at 18-19.

51 McFarlane at 4.

52 Wright at 16.

53 Smith at 22-23.

54 McFarlane at 6.

Import Limits ("CIL") and Capacity Export Limits ("CEL").[55] Each of these changes is discussed more fully below.

MISO proposes changes to the modeling and methodology of the LOLE study to more accurately model seasonally-sensitive variables and calculate the construct parameters through: (1) seasonal LOLE risk allocation; and (2) improving seasonal LOLE modeling, including the modeling of planned outages, modeling of non-firm external support (*i.e.,* imports), and hourly modeling of intermittent resources.[56] As explained by Mr. McFarlane, this new LOLE model needs to have a defined LOLE threshold for each Season to calculate seasonal Resource Adequacy reserve requirements.[57] Seasonal requirements will be determined under a two-step LOLE analysis.[58] For the first step, the LOLE model will be solved to an annual LOLE value of 0.1 day per year to determine the natural LOLE distribution.[59] If after the first step there is a minimum of 0.01 day per year LOLE in all four Seasons, then the seasonal requirements will be determined directly from this step and there will be no need for additional analysis.[60] If a Season has an LOLE of less than 0.01 day per year from step 1, then an additional step will be performed to solve that Season to an LOLE of 0.01 day per year.[61] In the second step, if required, MISO proposes to round LOLE targets up to a minimum of 0.01 day per year for any Season with LOLE less than 0.01 day per year, and to maintain LOLE targets for Seasons with LOLE greater than 0.01 day per year.[62]

In order to determine a Planning Reserve Margin ("PRM") for the four Seasons, MISO proposes performing an additional two-step LOLE analysis with seasonal input assumptions.[63] The LOLE model will be used to meet the seasonal LOLE targets by adjusting the capacity within the model up or down as needed.[64] If the LOLE is less than the target for a Season, then a "perfect unit" with a negative capacity value and zero forced outage rate will be added to the model.[65] If the LOLE is greater than the target for a Season, then proxy combustion turbine generators of typical size (160 MW) and class average Equivalent Forced Outage Rate Demand ("$XEFOR_d$") will be added to the model until the seasonal LOLE target is achieved.[66] Once the seasonal LOLE targets are met, the seasonal PRM values in terms of Unforced Capacity ("UCAP") will be

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55 *Id*. at 7.

56 *Id*. at 8.

57 *Id*. at 11.

58 *Id*.

59 *Id*. at 12.

60 *Id*.

61 *Id*.

62 *Id*.

63 *Id*.

64 *Id*. at 11.

65 *Id*. at 11-12.

66 *Id*.

calculated and expressed as a percentage of seasonal coincident peak demand.[67] The PRM for each Season is multiplied by the 50/50 forecast of coincident peak load to determine the PRMR (in MWs) for that Season.[68]

To determine zonal Local Reliability Requirements, MISO proposes using the same two-step process as the PRM analysis with each zone treated as an isolated system consistent with the existing LRR analysis methodology under the current annual PRA construct.[69] Seasonal LRR values will be calculated in terms of UCAP and expressed as a percentage of seasonal zonal coincident peak demand once the model has been solved to the appropriate LOLE targets.[70] The seasonal LRR values will be used to determine the seasonal LCR values by subtracting the seasonal CIL from the seasonal LRR.[71]

MISO proposes performing seasonal transfer analyses to determine seasonal CILs and CELs, capturing the seasonal variation of transfer limits for each LRZ.[72] Planning Year seasonal peak powerflow models and input files developed from MISO Transmission Expansion Plan studies will be used to perform transfer analysis for each Season including Summer Peak, Fall Peak, Winter Peak, and Spring Peak study models.[73] The resulting seasonal Zonal Import Ability ("ZIA"), in conjunction with controllable exports, will be used to determine the seasonal LCR for each LRZ.[74]

The proposed Resource Adequacy construct more accurately represents Resource capabilities at different times during the year, improves certainty of Resource availability outside the Summer Season, better incentivizes Resources to be available when needed, establishes seasonal reserve requirements that better align with risks, and delivers additional visibility into the risks throughout the year – which are not currently captured in the annual construct.[75] When discussing the expected impact of the seasonal approach on MISO's operations, Mr. Smith explains that the proposed reforms measure and mitigate non-Summer reliability risk. This is accomplished by calculating seasonal requirements using seasonal inputs based on demonstrated seasonal resource availability to ensure that seasonal risks are known and mitigated. In general, resource owners and LSEs benefit from lower non-Summer peak loads, resulting in lower non-Summer PRMRs that reduce the required cleared capacity and allow for seasonal operation and

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67 *Id*. at 13.

68 *Id*.

69 *Id*. at 13.

70 *Id*.

71 *Id*.

72 *Id*. at 13-14.

73 *Id*. at 14.

74 *Id*.

75 *Id*. at 7.

related cost savings.[76] Overall, this proposed seasonal shift is expected to identify and mitigate reliability risks across the year during the periods of highest reliability risk.

B. Revisions to the Planning Resource Auction

As discussed above, the annual PRA will continue to be administered in the Spring of each year in advance of the upcoming Planning Year beginning in June. In most instances, MISO's PRA processes will remain the same but will be applied on a seasonal basis rather than an annual basis. The PRA offer window will continue to be the last four business days in March. In addition, the "must offer" requirement for resources that clear the PRA will only apply in the Season or Seasons in which the Resource clears.[77] Moreover, MISO will increase the amount of time it has available to clear the PRA from 10 to 20 business days in order to clear the four Seasons. The following graphic shows the Seasonal PRA timeline:



C. Planning Resource Replacement and Capacity Replacement Non-Compliance Charge

MISO's current capacity replacement requirements are limited to suspensions and retirements of resources and carry no specific financial non-compliance provisions. As Mr. McFarlane explains, these limited requirements are no longer sufficient as the performance and availability of committed capacity to meet seasonal requirements will be critical.[78] As such, MISO proposes to require replacement for any Planning Resource that will be on planned outage or planned derate for more than 31 days in a Season in which they clear. Consistent with current Tariff requirements, replacement can only be made from uncleared ZRCs.[79] The capacity replacement requirement will also apply to resources that have received exemptions through the updated outage coordination process discussed below. MISO is also adding provisions allowing the replacement of resources that have experienced catastrophic outages, enabling such resources to maintain class average accreditation upon return to service, with further details to be established in the Business Practices Manual for Resource Adequacy. It is important to note that existing rules regarding deliverability and zonal transfer limits will still apply.

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76 Smith at 19

77 *Id*. at 37.

78 *Id*. at 38.

79 *Id*. at 40.

Given the critical impacts non-replacement of resources could have on reliability, MISO proposes a Capacity Replacement Non-Compliance Charge for Resource owners that do not replace Planning Resources that retire or suspend during the Season, or are on planned outage or planned derate for more than 31 days in a Season. Mr. McFarlane explains that the Capacity Replacement Non-Compliance Charge will be a be a daily charge, equal to the amount of ZRCs that failed to be replaced multiplied by sum of the Auction Clearing Price and the daily CONE value.[80] Capacity Replacement Non-Compliance Charges will be distributed to Market Participants representing LSEs on a *pro rata* basis, based upon the LSE's share of total PRMR for the MISO Region. Mr. McFarlane notes that the billing, invoicing, default, and uplift provisions will be similar to the existing Installed Capacity ("ICAP") Deferral Non-Compliance Charge.[81]

IV. AVAILABILITY-BASED ACCREDITATION

The shift to seasonal Resource Adequacy Requirements will impact all resources in the MISO Region; however, the availability-based accreditation provisions only apply to Capacity Resources that are Demand Response Resources or Generation Resources (collectively referred to as "Schedule 53 Resources"), but not Dispatchable Intermittent Resources, Intermittent Generation, Electric Storage Resources, External Resources or Use Limited Resources. MISO refers to these resources as "Schedule 53 Resources" because it submits herewith a new Schedule 53 to the MISO Tariff entitle Seasonal Accredited Capacity Calculation.

Mr. McFarlane explains that the proposed changes align resource accreditation for Schedule 53 Resources with historic availability and performance during the highest risk periods while also accounting for general availability of resources across the year.[82] To accomplish this, MISO proposes a two-tiered calculation to determine individual Resource accreditation by Season, as described below.[83]

A. Determination of RA Hours

Pursuant to MISO's proposal, resource accreditation for Schedule 53 Resources will no longer be based on forced outage rates from Generator Availability Data System (or "GADS"). Instead, accreditation for Schedule 53 Resources will primarily be based on the average real-time offered availability from MISO's Day-Ahead and Real-Time market system during times of highest need, which are referred to as "RA Hours" in MISO's proposal. Other factors such as the type and volume of interconnection service and a seasonally corrected Generation Verification Test Capacity ("GVTC") will be utilized as well. Mr. McFarlane explains that the proposed construct will continue to base accreditation on the three prior years starting September 1 through August 31 of the year prior to the Planning Year, which reflects the cumulative availability of a

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80 *Id*. at 39.

81 *Id*.

82 *Id*. at 16.

83 *Id*.

resource.[84] MISO proposes a tiered weighting structure to determine individual resource accreditation by Season based on each Resource's real-time offered availability during Tier I hours (*i.e.,* all hours not including RA Hours) and Tier 2 hours (*i.e.,* RA Hours) while incentivizing the coordination of Generator Planned Outages by providing exemptions when certain conditions are met, as discussed in further detail below.[85]

As indicated, MISO's Seasonal Accredited Capacity approach will shift to the application of RA Hours, which Mr. McFarlane explains represent the periods of highest risk and greatest need during a Season and throughout the year.[86] These periods include declared MaxGens and the hours when the operating margin is at its lowest. MISO proposes to determine RA Hours for each Season based on MaxGens and the 65 hours with the tightest operating margin, subject to a maximum operating margin threshold established at 25 percent.[87] Mr. McFarlane explains that RA Hours will be defined within the First Planning Area and Second Planning Area separately to reflect the growing frequency of MaxGens and emergencies that occur on either side of the Sub-Regional Power Balance Constraint, which have been driven by: trapped capacity in one sub-region due to the contractual transfer limits, increasing sub-regional challenges driven by portfolio differences, and the impacts of extreme weather including hurricanes, cold weather events, and renewable penetration.[88]

Pursuant to MISO's proposal, each Season will have a target of 65 RA Hours based on three (3) percent of the hours in a Season. Mr. McFarlane explains that the number of RA Hours in a Season can exceed the target when declared MaxGens during that Season have a cumulative duration greater than 65 hours.[89] The number of RA Hours in a Season can be less than the target because of the 25 percent maximum operating margin threshold, which will ultimately lead to a deficiency equal to the difference between the target RA Hours and the actual number of RA Hours.

B. Resource Specific Accreditation

1. Schedule 53 Resources

MISO's resource accreditation proposal is intended to reflect the anticipated capability and availability of Planning Resources during times when they are most needed. Mr. McFarlane explains that utilizing offered availability, including actual performance data during RA Hours provides an improved measure of expected availability.[90] Ultimately, MISO proposes a two-tiered

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84 *Id*. at 19.

85 *Id*. at 19-20.

86 *Id*. at 20.

87 *Id*. at 20.

88 *Id*. at 22.

89 *Id*. at 20.

90 *Id*. at 15.

weighting structure to calculate resource accreditation for Schedule 53 Resources that will reflect general availability while emphasizing availability during times of greatest need based on a tiered weighting structure.

Pursuant to the proposed Schedule 53, a Resource will have its Intermediate Seasonal Accredited Capacity ("ISAC") determined based on its real-time offered availability (Emergency Maximum Limit, or Targeted Demand Reduction Level for Demand Response Resources Type I) during seasonal RA Hours (Tier 2) and Non-RA Hours (Tier 1). The number of Tier 2 RA Hours may vary during individual Seasons when the 25% maximum margin threshold is applied or individual resources receive outage exemptions, impacting sample sizes of RA Hours and corresponding accreditation calculations. If Tier 2 RA Hours for a Season or a specific resource fall below the 3% target of 65 hours, a Resource's Annual Average Offered Capacity ("AAOC") will be used to supplement the deficient number of hours as part of the Tier 2 portion of the accreditation calculation. Seasonal Tier 1 Non-RA Hours on the other hand include all hours in a Season of a Planning Year, excluding except Tier 2 RA Hours and any hours where a Resource had an exemption or was not designated for Resource Adequacy Requirements ("RAR"). Mr. McFarlane's testimony provides a detailed description of this process, along with hypothetical examples.[91]

As described by Mr. McFarlane, MISO will determine ISAC values for each Resource for each Season in the upcoming Planning Year while the final SAC calculation is "in process."[92] The final ISAC value will be the weighted average over its values from the two tiers as described in Mr. McFarlane's testimony.[93] MISO proposes an 80% Tier 2 and 20% Tier 1 weighting as assigning the heavier weighting to Tier 2 tight conditions ensures the alignment between a resource's SAC value and its availability and performance during times of highest risk and greatest need. The basis for the 80% Tier 2 and 20% Tier 1 weighting is discussed further in section VII below.

In response to stakeholder feedback on the SAC proposal, MISO has implemented a transition to the full 80% Tier 2 weighting in the third Planning Year to account for the fact that the historical real-time offers, outages, and notification times used in the Schedule 53 calculations were submitted for resources without knowledge of the final accreditation methodology proposed in the instant filing. Under the proposal, Tier 2 weighting would start at 60% in PY 2023 / 24, rise to 70% in PY 2024 / 25 and then reach the full 80% in PY 2024 / 25.

In addition, MISO has adopted a UCAP to ISAC ratio proposed by its Independent Market Monitor to avoid undesirable impacts to PRA requirements and non-Schedule 53 resources. Application of this ratio addresses stakeholder concerns on deliverability and auction revenue reduction. The IMM presented its new ratio recommendation at the October 6, 2021 Resource Adequacy Subcommittee ("RASC") meeting, and formal feedback was solicited. Feedback

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91 *Id.* at 25-30.

92 *Id.* at 27.

93 *Id.* at 27-28.

received from stakeholders generally supported the revised conversion method and MISO adopted the revised method and shared related Tariff redlines at the November 3, 2021 meeting of the RASC.

2. Non-Schedule 53 Resources

As indicated, the majority of MISO's proposed resource accreditation revisions address Schedule 53 Resources. While MISO intends to address potential accreditation enhancements to non-Schedule 53 Resource accreditation in a future filing after development and stakeholder discussions, non-Schedule 53 Resources will receive a SAC value based on Resource type consistent with their current accreditation rules adjusted for seasonality. As explained by Mr. McFarlane, wind resources will receive accreditation for each Season based on seasonal Effective Load Carrying Capability studies with capacity credit allocated based on eight peak hours for each Season.[94] In addition, non-wind intermittent resources such as run-of-river hydro, solar, Behind the Meter Generation ("BTMG") and biomass will be based on historic output during hours ending 15, 16 and 17 Eastern Standard Time ("EST") for the relevant Spring, Summer, and Fall months. Winter accreditation will be based on hours 8, 9, 19 and 20 EST for the Winter months. Mr. McFarlane explains in his testimony that the selected hours represent the typical seasonal peak demand hours for the specified Seasons.[95] Finally, Demand Resources registered as LMRs will be accredited based on lead-time and number of calls per year consistent with current LMR rules, with adjustments to establish a minimum number of calls for each Season – five for Summer, five for Winter, three for Spring and three for Fall.[96]

C. Generator Outage Coordination

MISO's current Resource Adequacy construct provides for exemptions for generator planned outages if certain criteria are met.[97] MISO has since worked collaboratively with stakeholders to develop an exemption process that integrates with the tiered accreditation calculations in Schedule 53.[98] The three levels are: (1) full exemption for Generator Planned Outages from Tier 1 and Tier 2 SAC calculations in Schedule 53; (2) partial exemption (only exempt in Tier 1 SAC calculations); and (3) no exemption.[99] The table below detailing the proposed exemption requirements is also in Schedule 53 of the Tariff:

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94 *Id.* at 31.

95 *Id.* at 32.

96 *Id.*

97 *Id.* at 46.

98 *Id.* at 47.

99 *Id.*

Generator Outage Submission Criteria	**Maintenance Margin >=0 for duration of outage**	**Maintenance Margin <0 for any day in the duration of outage**
>120 days prior to outage start date, and >120 days from end of previous outage for unit	Exempt Tier 1 & 2	Exempt Tier 1 Only
>120 days Prior to Outage Start date and <120 days from end of Previous outage for unit or Outage submitted between 31-119 days Prior to outage start date	Exempt Tier 1 Only	No Exemption
14-30 days prior to outage start date and passes No Harm Test	Exempt Tier 1 Only	No Exemption
Outage moved per MISO request	Exempt Tier 1 & 2 (Weather, forced outages, other conditions in BPM-008)	Exempt Tier 1 & 2 (Weather, forced outages, other conditions in BPM-008) at Transmission Provider's discretion

MISO's outage exemption analysis will apply no harm tests that include, but will not be limited to, outage approval, compliance with all applicable operation guides, review of possible conflicting outages or system conditions, and forecasts of system capacity.[100] The tests will also include criteria outlined in the Business Practices Manual for Outage Coordination and will apply only to specific categories of outages.[101]

For those planned outages submitted before MISO's proposal goes into effect, MISO proposes a transition with a bright-line distinction based on whether the outage is scheduled to start before September 1, 2022.[102] Planned outages submitted since Spring 2019 are coded as exempt or not in the Control Room Operations Window ("CROW") under RAN Phase 1.[103] Exempt resources will be treated as fully exempt for Tier 1 and 2 even though they may not have met both of the primary requirements of: (1) being submitted 120 days or greater in advance; and, (2) leaving positive Maintenance Margin in the subregion for the duration of the outage.[104] As explained by Mr. McFarlane, MISO believes this approach is appropriate given the risks to

100 *Id.* at 48.

101 *Id.*

102 *Id.*

103 *Id.*

104 *Id.*

capacity sufficiency from correlated planned outages and its ongoing efforts to encourage sufficient outage coordination.[105]

In light of the strong correlation between high outage levels and MaxGen events, MISO proposes to implement processes and procedures to enhance SAC determinations for Schedule 53 resources.[106] Under MISO's proposed framework, outage exemptions will usually be given at the time of outage submittal review or in response to a CROW ticket change request.[107] Partial and full exemptions ensure that a Resource's accreditation is appropriately impacted based on adherence to the outage coordination criteria.[108] The criteria for exemptions are outage lead time and adequate Maintenance Margin.[109] Mr. McFarlane notes that outage approvals and outage exemptions have separate purposes and criteria but bridge the gap between the planning and operational horizons.[110] As is the case today, approvals will be based on reliability analysis in the Outage Coordination process.[111]

MISO is also developing enhancements to Maintenance Margin to improve the information available to Resource owners scheduling outages. Maintenance Margin is the maximum megawatt of additional generation that can be taken out of service for planned maintenance for a given time-period without undue risk to supply adequacy for MISO's Balancing Authority Area, including MISO sub-regions.

Full outage-related exemptions (exempt Tier 1 and Tier 2) will be provided if: (1) the generator owner or operator schedules its first planned outage 120 days or more in advance of the outage start date and 120 days or more beyond the end date of any previously scheduled outages for the unit, and certain projected Maintenance Margin levels are met; and (2) the generator owner or operator reschedules its planned outage at MISO's request due to certain enumerated conditions.[112] These criteria are set forth in additional detail in Schedule 53 and the Testimony of Mr. McFarlane.

Partial outage-related exemptions (exempt Tier 1 only) will be provided if one of the following conditions are met: (1) the generator owner or operator schedules its first generator planned outages 120 days or more in advance of the outage start date and 120 days or more beyond the end date of any previously scheduled outages for the unit; (2) a subsequent generator unit outage requests 120 days or more in advance and/or generator owner or operator's planned outage is less than 120 days in advance but at least 31 days in advance of outage start date; (3) the planned

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105 *Id.* at 48-49.

106 *Id.* at 49.

107 *Id.*

108 *Id.*

109 *Id.* at 49-50.

110 *Id.* at 50.

111 *Id.*

112 *Id.* at 47.

outage is less than 31 days in advance but at least 14 days in advance of outage start date; or (4) the generator owner or operator reschedules its planned outage at the Transmission Provider's request. These criteria are set forth in additional detail in Schedule 53 and the Testimony of Mr. McFarlane.

V. OTHER RELATED ENHANCEMENTS

A. Market Monitoring and Mitigation Revisions

MISO also intends to modify its market monitoring and mitigation provisions in Module D of the Tariff. More specifically, the revisions to Module D of the Tariff focus, in part, on substantive enhancements regarding physical and economic withholding.[113] With regard to physical withholding, the shift to a seasonal construct requires minor modifications to ensure existing protections continue to work in the future.[114] MISO proposes to remove the preclusion from participation for resources that expect to be on outage for greater than 90 of the first 120 days of the Planning Year and replace that with a provision that states that a Market Participant with a Resource that has submitted an outage for greater than 31 days of a Season can ask the IMM for a determination ahead of the auction allowing it to forego offering excess Zonal Resource Credits from the Resource into the PRA, without being deemed to have engaged in physical withholding.[115]

The shift to a seasonal construct could mean that a Resource may only be able to recover capacity revenues in a single Season, which need to cover its relevant costs of being designated for Resource Adequacy Requirements.[116] The threshold for economic withholding remains at 10% of daily CONE but it is expected that more Resources will request facility-specific Reference Levels or use Default Technology Specific Avoidable Costs to help ensure they can cover their costs when they might only clear for one Season in contrast to the full Planning Year under the current construct.[117] The threshold for economic withholding remains at $0 when a Resource has a facility-specific Reference Level at which it can offer.[118]

B. Make-Whole Payment / Revenue Sufficiency Guarantee

When evaluating the shift to the seasonal PRA construct, MISO identified rare circumstances that result in the potential for over or underpayment. As explained by Mr. McFarlane, historical PRA results suggest that these situation will not occur frequently but,

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113 *Id.* at 50.

114 *Id.* at 51.

115 *Id.*

116 *Id.*

117 *Id.*

118 *Id.*

nonetheless, it is reasonable to ensure mitigation for such potential instances.[119] To address this potential risk, MISO proposes enhancements to its offer caps and will add the ZRC Offer Revenue Sufficiency Guarantee Credit to ensure Resources clearing the PRA recover their costs reflected in their offer while also ensuring the LSEs are not exposed to Auction Clearing Prices that result in charges that amount to multiples of the annual CONE value as a result of participation in the PRA. Mr. McFarlane's testimony contains specific descriptions of the proposed Auction Clearing Price adjustments and make whole payment provisions.[120]

Charges to fund the ZRC Offer Revenue Sufficiency Guarantee will be allocated to Market Participants representing LSEs in the LRZ(s) experiencing shortage or near shortage conditions *pro rata,* based on their respective LSEs' share of the PRMR within the LRZs during the Season or Seasons where the Auction Clearing Prices were reduced.[121] Mr. McFarlane notes in his testimony that this allocation of ZRC Offer Revenue Sufficiency Guarantee charges is similar to the allocation of the Zonal Deliverability Benefit, which occurs when an LRZs' Auction Clearing Price separates from the Region-wide Auction Clearing Price due to limited import or expert capability.[122]

VI. STAKEHOLDER ENGAGEMENT

MISO has been engaged in dedicated, detailed discussions with stakeholders at the RASC and RAN workshops about these proposed reforms since March 2020. As previously referenced, however, issues identified prior to and throughout the RAN initiative were discussed with stakeholders as early as 2015. As described above, MISO has already taken action with FERC filings related to outage coordination and LMRs in 2018, 2019 and 2020. Regarding the current proposals, MISO has discussed a variety of alternatives since 2017 through the stakeholder issues process and the publication of various "white-papers." Attached to Mr. Wright's testimony as Exhibit A is a table outlining the numerous meetings and topics covered with stakeholders during the development to this proposal. As indicated by the table, stakeholder involvement in the development and evaluation of this proposal has been extensive.

Stakeholders have passed three motions requesting that MISO delay its filing, specifically citing the need for additional time to understand MISO's proposal. The details of these motions and related vote tallies are described in detail in the testimony of Mr. Wright. MISO responded to a stakeholder motion passed at the September 2021 RASC requesting that MISO delay the instant filing beyond the planned September 30, 2021 filing date and provided stakeholders with an additional two months to continue discussions. While the filing was not delayed into 2022 as requested by the motion, MISO held three additional RASC meetings and three additional stakeholder workshops to further discuss stakeholder questions and concerns. In addition, MISO established a formal question and answer process with written and verbal responses. This included

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119 *Id.* at 40.

120 *Id.* at 39-46.

121 *Id.* at 45.

122 *Id.*

the cataloging and responding to over 120 questions through the formal stakeholder feedback process.[123] In parallel to the RASC and RAN workshops mentioned above focusing on MISO's proposal, MISO held one implementation workshop to solicit stakeholder inputs on MECT tool enhancements in support of transitioning to proposed Resource Adequacy reforms.

During these additional stakeholder discussions, MISO made several refinements and improvements to the proposal. These modifications include the following: implementation of the UCAP/ISAC ratio; provisions for catastrophic outage replacements; resource capacity increases during the Planning Year; transitional Tier 1 and Tier 2 weightings of 20% and 80%, respectively; Auction Clearing Price adjustment during scarce and near-scarce conditions; and, provisions to address revenue sufficiency under rare circumstances. Many of these changes were proposed by stakeholders through written and verbal feedback. MISO evaluated each proposal to determine consistency with the objectives of current proposal and potential reliability or efficiency impacts. Based on that evaluation and upon discussions with the IMM, MISO believes these changes to be reasonable and has included them in its final proposal. The specific Tariff changes described below reflect these changes and their merits are discussed in the testimony submitted with this filing.

MISO appreciates the willingness of all its stakeholders and state regulators to review and comment on this final proposal, which MISO believes reasonably accommodates concerns raised by stakeholders.

VI. TARIFF REVISIONS

MISO proposes the following revisions to its Tariff to implement its proposed Resource Adequacy reforms including Seasonal Resource Adequacy Construct and Availability-Based Accreditation.

A. Module A - Common Tariff Provisions – Definitions

1. Allowable ZRC Offer Costs

MISO proposes adding the definition of Allowable ZRC Costs to specify that Allowable ZRC Offer Costs means "[c]osts associated with a Planning Resource reflected in its ZRC offer, or the CONE, or facility-specific Reference Level costs, considered in determining ZRC Offer Revenue Sufficiency Credits for a Planning Year."

2. Auction Clearing Price (ACP)

MISO proposes modifying the definition of Auction Clearing Price by inserting the phrase "for a Season" into the definition to clarify that Auction Clearing Price means the price associated with the MW quantity that clears in the Planning Resource Auction for a given LRZ or ERZ for a Season for the applicable Planning Year.

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123 *See* https://cdn.misoenergy.org/20211118%20RA%20Construct%20Workshop%20Item%2002c%20Review%20Q%20and%20A605111.pdf

3. Border External Resource

MISO proposes modifying the definition of Border External Resource by replacing "Unforced Capacity" with "Capacity" in the definition to clarify that a Border External Resource means an External Resource that: (i) has direct interconnection facilities to a substation that contains the terminal of a transmission line under the Transmission Provider's functional control; (ii) will schedule in response to notification by the Transmission Provider during a declared Energy Emergency solely from unit(s) connected to each substation; and, (iii) whose Capacity offered into MISO may be accommodated on those transmission line(s) under the Transmission Provider's functional control.

4. Capacity Deficiency Charge

MISO proposes modifying the definition of Capacity Deficiency Charge by inserting language into the definition to clarify that Capacity Deficiency Charge means a charge that is assessed to an LSE that has provided notification prior to the Planning Resource Auction that it will meet its PRMR in part or in whole by paying the Capacity Deficiency Charge so that the Transmission Provider does not clear associated Zonal Resource Credits ("ZRC") for the associated PRMR through the PRA.

5. Capacity Export Limit (CEL)

MISO proposes modifying the definition of Capacity Export Limit by inserting the phrase "for each Season" into the definition to clarify that Capacity Export Limit means the amount of Planning Resources in MWs for an LRZ or ERZ determined by the Transmission Provider that can be reliably exported from that LRZ or ERZ for each Season.

6. Capacity Import Limit (CIL)

MISO proposes modifying the definition of Capacity Import Limit by inserting the phrase "for each Season" into the definition to clarify that Capacity Import Limit means the amount of Planning Resources in MWs for an LRZ determined by the Transmission Provider that can be reliably imported into that LRZ for each Season.

7. Capacity Replacement Non-Compliance Charge

MISO proposes adding the definition of Capacity Replacement Non-Compliance Charge to specify that Capacity Replacement Non-Compliance Charge means "[t]he charge assessed to a Market Participant for failing to replace ZRCs that were designated for RAR and did not fulfill their performance obligations as set forth in Module E-1."

8. Catastrophic Generator Outage

MISO proposes adding the definition of Catastrophic Generator Outage to specify that Catastrophic Generator Outage means a forced outage that results in a unit being, or reasonably expected to be unavailable for a minimum of six (6) continuous months, which is not the result of a planned maintenance outage.

9. Coincident Peak Demand

MISO proposes modifying the definition of Coincident Peak Demand by inserting the phrase "for each Season" into the definition to clarify that Coincident Peak Demand means the

demand in MWs, for an LSE and/or EDC, that occurs coincident to the peak Demand for each Season, where all Demand has been augmented to include any known reductions in Demand related to LMRs and/or Energy Efficiency Resources.

10. Deliverability Benefit Zone

MISO proposes modifying the definition of Deliverability Benefit Zone by inserting the phrase "for a Season" into the definition to clarify that Deliverability Benefit Zone means a group of Local Resource Zones that have equal Auction Clearing Prices for a Season in a Planning Resource Auction resulting from the same auction constraint.

11. Diversity Contract

MISO proposes modifying the definition of Diversity Contract by removing the phrases "for the period between June 1st and September 30th" and "for any period during October 1st to May 31st" to clarify that Diversity Contract means a type of power purchase agreement between an LSE in the Transmission Provider Region and an LSE with demand external to the Transmission Provider Region that includes a one for one MW exchange of capacity which is committed to the Transmission Provider Region in exchange for capacity committed outside of the Transmission Provider Region.

12. Fixed Resource Adequacy (FRAP)

MISO proposes modifying the definition of Fixed Resource Adequacy Plan by inserting the phrase "in a Season" into the definition to clarify that Fixed Resource Adequacy Plan means a plan submitted by an LSE through the MECT to the Transmission Provider that is approved by the Transmission Provider which demonstrates that the LSE has sufficient ZRCs to meet all or part of its PRMR for one or more LRZs in a Season.

13. ICAP Deferral Non-Compliance Charges

MISO proposes modifying the definition of ICAP Deferral Non-Compliance Charges by inserting the phrase "start of any Season for which a Market Participant has an ICAP deferral" into the definition to clarify that ICAP Deferral Non-Compliance Charges means a charge that is assessed by a Market Participant that fails to submit GVTC results, demonstrate deliverability, demonstrate commercial operation, and/or replace ZRCs by the last Business Day prior to the start of any Season for which a Market Participant has an ICAP deferral associated with Planning Resources that participate in the Resource Adequacy Requirements provisions, including the Planning Resource Auction and the Fixed Resource Adequacy Plan.

14. Local Clearing Requirement (LCR)

MISO proposes modifying the definition of Local Clearing Requirement by replacing "Unforced Capacity" with "Seasonal Accredited Capacity" and inserting the phrase "for each Season" into the definition to clarify that Local Clearing Requirement means the minimum amount of Seasonal Accredited Capacity for an LRZ that is required to meet its LOLE for each Season while fully using the Zonal Import Ability for such LRZ and accounting for controllable exports.

15. Local Clearing Requirement Charge

MISO proposes modifying the definition of Local Clearing Requirement Charge by inserting the phrase "for a Season" into the definition to clarify that Local Clearing Requirement

Charge means a charge that is assessed to Load Serving Entities whenever an LRZ's Auction Clearing Price for a Season is increased due to its LCR being greater than the sum of individual PRMR of the LSEs.

16. Local Reliability Requirement (LRR)

MISO proposes modifying the definition of Local Reliability Requirement by inserting the phrase "for each Season" into the definition to clarify that Local Reliability Requirement means the minimum of amount of Unforced Capacity for an LRZ to meet its LOLE for each Season, without considering transmission ties to systems outside of the LRZ.

17. Local Resource Zone Peak Demand

MISO proposes modifying the definition of Local Resource Zone Peak Demand by removing the word "annual" and inserting the phrase "for each Season" into the definition to clarify that Local Resource Zone Peak Demand means the Demand in MWs, for an LSE and/or EDC, in a Local Resource Zone that occurs coincident to the peak Demand for each Season in the Local Resource Zone, where all Demand has been augmented to include any known reductions in Demand related to LMRs and/or Energy Efficiency Resources.

18. Loss of Load Expectations (LOLE)

MISO proposes modifying the definition of Loss of Load Expectation by removing the phrase "[t]he requirement is set such that the loss of Load is no greater than 0.1 day in one (1) year" from the definition to clarify that Loss of Load Expectation means the sum of the loss of Load probability for the integrated daily peak Hour for each Day of the year.

19. Planning Reserve Margin Requirement (PRMR)

MISO proposes modifying the definition of Planning Reserve Margin Requirement by inserting the phrase "in each Season" into the definition to clarify that Planning Reserve Margin Requirement means the amount of ZRCs required of each LSE with Coincident Peak Demand in an LRZ to meet the LSE's Resource Adequacy Requirements in each Season.

20. Planning Resource Auction (PRA)

MISO proposes modifying the definition of Planning Resource Auction by replacing the phrase "annual" with the phrase "each Season in" in the definition to clarify that Planning Resource Auction means auctions conducted by the Transmission Provider to determine the ACP and the cleared ZRC Offers for each LRZ and ERZ for each Season in the applicable Planning Year.

21. Seasonal Accredited Capacity (SAC)

MISO proposes adding the definition of Seasonal Accredited Capacity to specify that Seasonal Accredited Capacity means the amount of Capacity, for a given Season, in MW, assigned to a Planning Resource after accounting for its historic availability.

22. Sub-Regional Export Constraint (SREC)

MISO proposes modifying the definition of Sub-Regional Export Constraint by inserting the phrase "for each Season" into the definition to clarify that Sub-Regional Export Constraint means the amount of Planning Resources in megawatts modeled in the PRA for each Season within an applicable Sub-Regional Resource Zone ("SRRZ") that can be cleared in excess of the total

individual LRZ's PRMR comprising the SRRZ in accordance with applicable seams agreements, coordination agreements, or transmission service agreements.

23. Sub-Regional Import Constraint (SRIC)

MISO proposes modifying the definition of Sub-Regional Import Constraint by inserting the phrase "for each Season" into the definition to clarify that Sub-Regional Import Constraint means the amount of Planning Resources in megawatts modeled in the PRA for each Season, not within an applicable Sub-Regional Resource Zone ("SSRZ"), that can be cleared to meet the total PRMR of the individual LRZs comprising the SRRZ in accordance with applicable seams agreements, coordination agreements, or transmission service agreements.

24. Sub-Regional Resource Zone (SRRZ)

MISO proposes modifying the definition of Sub-Regional Resource Zone by removing the reference to Module E-2 and inserting the phrase "for each Season" into the definition to clarify that Sub-Regional Resource Zone means a zone, comprised of a LRZ or combination of two or more LRZs, established by the Transmission Provider for each Season for Resource Adequacy Requirements under Module E-1 to administer constraints in accordance with applicable seams agreements, coordination agreements, or transmission service agreements.

25. System Auction Clearing Price (System ACP)

MISO proposes modifying the definition of System Auction Clearing Price by inserting the phrase "for a Season" into the definition to clarify that System Auction Clearing Price means the marginal value ("shadow price") associated with the system-wide Demand constraint for a Season. This Demand constraint ensures that the amount cleared, in all LRZs, is at least equal to the total PRMR in all LRZs. The marginal value of this constraint provides a quantitative result of the value of obtaining the marginal MW from the non-export constrained LRZ(s).

26. Zonal Resource Credit (ZRC)

MISO proposes modifying the definition of Zonal Resource Credit by replacing "Unforced Capacity" with "Seasonal Accredited Capacity" in the definition to clarify that Zonal Resource Credit means a MW unit of Planning Resource which has been converted from a MW of Seasonal Accredited Capacity to a credit in the MECT, which is eligible to be offered by a Market Participant into the PRA, to be sold bilaterally, and/or to be submitted through a FRAP.

27. ZRC Near-Shortage Conditions

MISO proposes adding the definition of ZRC Near-Shortage Conditions to specify that ZRC Near-Shortage Conditions means any Season in a Planning Resource Auction in which there is sufficient volume of ZRC Offers in the LRZ, group of LRZs, or SRRZ to cover PRMR and locational requirements minus the PRMR associated with the Capacity Deficiency Charge for the LRZ, group of LRZs, or SRRZ, but the Season's ACP is greater than the daily CONE value (i.e. 1/365 times CONE).

28. ZRC Offer Revenue Sufficiency Credit

MISO proposes adding the definition of ZRC Offer Revenue Sufficiency Credit to specify that ZRC Offer Revenue Sufficiency Credit means a Resource credit guaranteed by the Transmission Provider ensuring the minimum recovery of the actual costs a Planning Resource

that has been cleared for one or more Seasons in the Planning Resource Auction needed to be incurred by the Planning Resource to be available for the cleared Season(s).

29. ZRC Shortage Conditions

MISO proposes adding the definition of ZRC Shortage Conditions to specify that ZRC Shortage Conditions means any Season in a Planning Resource Auction in which there is an insufficient volume of ZRC Offers to cover LCR or the total PRMR for the LRZ, group of LRZs, or SRRZ minus the amount of PRMR associated with the Capacity Deficiency Charge for an LRZ, group of LRZs, or SRRZ, or the total PRMR for the SRRZ minus the SRIC minus the amount of PRMR associated with the Capacity Deficiency Charge for a SRRZ.

30. Transitional Planning Resource Auction (TPRA) and Module E-2 References

MISO proposes deleting the definition of Transitional Planning Resource Auction ("TPRA") as well as all references to the TPRA and to Module E-2 (which establishes the TPRA) throughout the Tariff. Such references are no longer needed because new transitional auction provisions will need to be developed in order to accommodate the proposed seasonal Resource Adequacy construct. For example, any new Market Participant proposing to integrate Schedule 53 type Resources into MISO mid-Planning Year will not have available data necessary for MISO to establish appropriate accreditation. In this regard, MISO notes that, upon acceptance of this filing by the Commission, MISO proposes to submit a separate Section 205 filing to cancel Module E-2 and remove it from the Tariff. In addition, MISO expects to establish and file with the Commission new transitional seasonal PRA provisions, as may be necessary.

B. Module A - Section 7.11 - Billing Procedure for Capacity Deficiency Charge and Capacity Replacement Non-Compliance Charge

MISO proposes adding Tariff language to Section 7.11 of the Tariff to clarify that the billing procedure for Capacity Deficiency Charges set forth in Section 7.11 of the Tariff will also apply to Capacity Replacement Non-Compliance Charges. Specifically, the language will require that five business days after the assessment of the Capacity Deficiency Charge or Capacity Replacement Non-Compliance Charge; or as soon as practical thereafter the Transmission Provider shall submit an invoice to Market Participants for charges owed that are associated with capacity deficiencies or the Capacity Replacement Non-Compliance Charge pursuant to the Tariff.

C. Module A - Section 7.13 - Default and Past Due Capacity Deficiency Charge, Capacity Replacement Non-Compliance Charge and ICAP Deferral Non-Compliance Charges

MISO proposes adding Tariff language to Section 7.13 of the Tariff to clarify that the rights and remedies for default and past due Capacity Deficiency Charges set forth in Section 7.13 of the Tariff will also apply to Capacity Replacement Non-Compliance Charges.

D. Attachment L – Credit Policy

MISO proposes modifying Attachment L of the Tariff by inserting language to clarify that Capacity Replacement Non-Compliance Charges will also be excluded from the Resource Adequacy Requirements Estimated Exposure calculation as they are settled all at once rather than daily.

E. Attachment UU – Energy Efficiency Resources Measurement & Verification Procedures

MISO proposes modifying Attachment UU of the Tariff by replacing coincident peak load with "Coincident Peak Demand" throughout the attachment and adding language related to "Season(s) in the" Planning Year, "Season", "in any Season", "applicable Season(s)", and "each Season in the Planning Year which the EE Resource expects to qualify" throughout the attachment.

MISO proposes inserting language into Attachment UU specifying that the hours in the Season for which the coincident peak is likely to occur "currently include the hours 15:00, 16:00, and 17:00 Eastern Prevailing Time (EPT) for the Spring, Summer, and Fall Seasons and hours 08:00, 09:00, 19:00, and 20:00 EPT for the Winter Season."

F. Module C - Energy and Operating Reserve Markets

1. Section 38.2.5 - Market Participant Obligations

MISO proposes modifying Sections 38.2.5 of the Tariff by adding language to Section 38.2.5.g.vii of the Tariff to clarify that if a Market Participant refuses to reschedule a Proposed Generator Planned Outage as requested by the Transmission Provider, then during the next Planning Year, the Transmission Provider shall determine the Seasonal Accredited Capacity value for such Generation Resource under RAR by treating the outage as a Forced Outage. MISO proposes inserting Section 38.2.5.g.viii specifying that "[a] Resource may be eligible for accreditation adjustments for purposes of RAR pursuant to Schedule 53 based on the advance notification requirements set forth in Sections 38.2.5.g.ix and 38.2.5.g.x." MISO proposes removing language from Section 38.2.5.g.ix-xi regarding the forced outage rate adjustment.

2. Section 39.2.5A - Demand Response Resource-Type 1 Offer Rules

MISO proposes modifying Section 39.2.5A.b.ix of the Tariff by replacing "Unforced Capacity" with "Seasonal Accredited Capacity".

3. Section 40.2.5 - Generation Offer, DRR-II Offer, or SER-II Offer

MISO proposes modifying Section 40.2.5.b.xv of the Tariff by replacing "Unforced Capacity" with "Seasonal Accredited Capacity".

G. Module D - Market Monitoring and Mitigation Measures

1. Section 53.1 – Conditions, Functions or Actions Monitored

MISO proposes modifying Section 53.1 of the Tariff by removing the phrase "other than ZRCs" from Section 53.1.b regarding the IMM's analysis of conditions, functions, or actions.

2. Section 53.1A – Auditing Physical Withholding

MISO proposes modifying Section 53.1A of the Tariff by inserting the phrase "Stored Energy Resources," "Electric Storage Resources," and "Generator Planned Outages" to clarify that "[i]n order to prevent and/or discern the exercise of market power by Stored Energy Resources, Electric Storage Resources, and certain Generation Resources, including Stored Energy Resources – Type II through Physical Withholding, the IMM shall audit Generator Forced Outages, Generator Planned Outages, and Generator deratings" and other changes.

3. Section 64.1.1 - Thresholds for Identifying Physical Withholding

MISO proposes modifying Section 64.1.1 of the Tariff by removing Section 64.1.1.g.ix regarding the 2015-2016 Planning Year, inserting the phrase "Season of the applicable" Planning Year into Sections 64.1.1.g.i-iii, and modifying renumbered Section 64.1.1.g.xi to clarify that "Market Participants with capacity expected to be on outage for greater than thirty-one (31) Days in a Season of the Planning Year may submit documentation of such circumstances to the IMM, and the IMM shall provide a written explanation upon request of its determination to the Market Participant regarding whether that capacity can forego participation without being deemed to have engaged in Physical Withholding. The portion of a Resource that the IMM has determined can forego participation based on full or partial outage expected to exceed thirty-one (31) Days in a Season of the Planning Year can still offer the excluded portion of the Resource in the relevant Season, if it so chooses, up to the annual CONE value divided by the number of days in the Season without needing to request a facility-specific Reference Level and will not be investigated for economic withholding in that Season."

4. Section 64.1.2 - Thresholds for Identifying Economic Withholding

MISO proposes modifying Section 64.1.1 of the Tariff by inserting the phrase "a threshold equal to the sum of 10% of the applicable CONE value divided by the number of days in the Planning Year for the Local Resource Zone where the Zonal Resource Credit is located and the applicable Reference Level for the Zonal Resource Credit" into section 64.1.2.d and by clarifying that "[i]f the Zonal Resource Credit Offer is associated with a Planning Resource that has a facility-specific Reference Level pursuant to Section 64.1.4.f, for which the IMM shall instead use a threshold of $0/MW-day above the facility-specific Reference Level."

5. Section 64.1.4 - Reference Levels

MISO proposes modifying Section 64.1.4 of the Tariff by replacing "Unforced Capacity" with "Seasonal Accredited Capacity" in Section 64.1.4.f.ii and by inserting language throughout Section 64.1.4 clarifying that Reference Levels shall be calculated based on Seasons and seasonal costs and inserting language regarding seasonal operations and seasonal shutdowns.

MISO proposes modifying Section 61.1.4.f.iii.c.2.ii-iii specifying with respect to forecasts for the Planning Resource to be in service that "[a]fter the applicable Season, the remainder of the 24 months should reflect the anticipated operations of the Planning Resource in the absence of capacity revenues. Typically, the Operating Forecast would show the costs of proceeding with retiring or suspending the Resource as applicable at the conclusion of the Season but it may show suspensions for just select Seasons of the year" and with respect to a forecast of the cost to retire, suspend, or keep a Planning Resource in suspension that "[a]fter the applicable Season, the remainder of the 24 months should reflect the anticipated operations of the Planning Resource in the absence of capacity revenues. Typically, the Operating Forecast would show the costs of proceeding with retiring or suspending the Resource as applicable at the conclusion of the Season but it may show suspensions for just select Seasons of the year."

6. Section 64.2.1 - Market Impact Thresholds

MISO proposes modifying Section 64.2.1 of the Tariff by inserting the phrase "divided by the number of days in the Planning Year" into Section 64.2.1.e to clarify that "[t]he threshold to determine a substantial effect on Auction Clearing Prices for Planning Resources shall be an

increase in the Auction Clearing Price equal to ten (10) percent of the CONE value divided by the number of days in the Planning Year."

7. Section 65.3.2 - Base Penalty Amount

MISO proposes modifying Section 65.3.2 of the Tariff by inserting language regarding the "Season of the" Planning Year into Section 65.3.2.c to clarify that the Penalty Period will be based on the Season of the Planning Year in which capacity was deemed to be withheld by a Market Participant from the auction and the phrase "applicable Season of the" Planning Year into Section 65.3.2.d to clarify that the Penalty Price for conduct affecting the outcomes of a PRA will be based on the Auction Clearing Price for the applicable Season of the Planning Year.

H. Module E-1 – Resource Adequacy

1. 68A – Introduction

MISO proposes modifying the Introduction to Module E-1 to clarify that "Module E-1 includes provisions for establishing Local Resource Zones and associated limits (*i.e.*, Capacity Import Limits (CIL) and Capacity Export Limits (CEL)); establishing Local Reliability Requirements (LRR); establishing Local Clearing Requirements (LCR); establishing External Resource Zones and associated limits (i.e. Capacity Export Limits (CEL)); determining the Planning Reserve Margin, Coincident Peak Demand forecasting; Local Resource Zone Peak Demand forecasting; qualifying and quantifying Planning Resources; participation of Demand and Planning Resources in the Planning Resource Auction process; settlement provisions; and Planning Resource performance requirements for each Season."

2. Section 68A.1 – Establishment of Planning Reserve Margins

MISO proposes modifying Section 68A.1 of the Tariff by inserting the phrases "in terms of Unforced Capacity for each Season" and "regulatory authority" into the Establishment of Planning Reserves Margins section to clarify that the PRM will be determined for each Season and that if a state regulatory authority establishes a PRM that is higher or lower than the PRM determined by the Transmission Provider, then the state regulatory authority-established PRM will apply to the Coincident Peak Demand of LSEs under that state's jurisdiction.

3. Section 68A.2 – Planning Reserve Margin Analysis

MISO proposes modifying Section 68A.2 of the Tariff by inserting the phrase "for each Season" to clarify that the Transmission Provider shall perform a technical analysis on an annual basis to establish the PRM for each Season for the Transmission Provider Region and by removing the word "resource" from the phrase specific Planning Resource reserve requirements.

4. Section 68A.2.1 – Loss of Loss Expectation Analysis

MISO proposes modifying Section 68A.2.1 of the Tariff by inserting the phrase "Season in the" Planning Year to clarify that the Transmission Provider shall coordinate with Market Participants to determine the appropriate PRM for the applicable Season in the Planning Year based upon the probabilistic analysis of being able to reliably serve the Transmission Provider Region's Demand for the applicable Season in the Planning Year.

MISO proposes modifying Section 68A.2.1 of the Tariff by inserting language into Section 68A.2.1 to clarify that "[t]he following process will be utilized to determine the minimum PRM

requirement for each Season in the Planning Year using the LOLE analysis. First, an LOLE analysis for the Planning Year will be conducted such that the LOLE for the Planning Year is one (1) day in ten (10) years, or 0.1 day per year, by either adding or removing capacity."

MISO proposes inserting additional language into Section 68A.2.1 to clarify that "[i]f the LOLE for the Planning Year is less than 0.1 day per year, a perfect negative unit with zero forced outage rate will be added until the LOLE reaches 0.1 day per year. If the LOLE for the Planning Year is greater than 0.1 day per year, proxy units based on a unit of typical size and forced outage rate will be added to the model until the LOLE reaches 0.1 day per year."

MISO proposes inserting additional language into Section 68A.2.1 to clarify that "[i]f the LOLE for a Season is equal to or greater than 0.01 day per year, the minimum PRM requirement for that Season will be calculated based on this LOLE analysis. If the LOLE for any Season is less than 0.01 day per year, an additional LOLE analysis will be performed to determine a minimum PRM requirement for that Season by adding a perfect negative unit with zero forced outage rate to that Season until the LOLE in that Season reaches 0.01."

MISO proposes inserting additional language into Section 68A.2.1 clarifying that the PRM will first be established as an Unforced Capacity requirement based upon the weighted average forced outage rate of all Planning Resources in the Transmission Provider Region.

5. Section 68A.3.1 – Establishment of SRRZs, SRECs, and SRICs

MISO proposes modifying Section 68A.3.1 of the Tariff by inserting language to clarify that the provisions regarding establishing SRRZs, SRECs, and SRICs apply to each "Season" and that the Transmission Provider's feasibility analysis is to review operation events from "each Coincident Peak Demand hour during the previous Planning Year."

6. Section 68A.4 – Establishment of CIL and CEL Limits

MISO proposes modifying Section 68A.4 of the Tariff by inserting language to clarify that the provisions regarding establishing CIL and CEL Limits apply to each "Season."

7. Section 68A.5 – Establishment of Local Reliability Requirements

MISO proposes modifying Section 68A.5 of the Tariff by inserting language to clarify that the LRR metric for each LRZ relates to "each Season", the forecasted Local Resource Zone Peak Demand relates to "each Season", and that "[f]irst, the LOLE analysis for the Planning Year will be conducted," that "[i]f the LOLE for the Planning Year is less than 0.1 day per year, a perfect negative unit with zero forced outage rate will be added until the LOLE reaches 0.1 day per year. If the LOLE for the Planning Year is greater than 0.1 day per year, proxy units based on a unit of typical size and forced outage rate will be added to the model until the LOLE reaches 0.1 day per year," and that "[i]f the LOLE for a Season is equal or greater than 0.01 day per year for the LRZ, the LRR for that Season will be calculated based on this LOLE analysis. If the LOLE for any Season is less than 0.01 day per year for the LRZ, an additional LOLE analysis will be performed to determine the LRR for that Season by adding a perfect negative unit with zero forced outage rate to that Season until the LOLE in that Season reaches 0.01 day per year for the LRZ."

8. Section 68A.6 – Establishment of Local Clearing Requirements

MISO proposes modifying Section 68A.6 of the Tariff by inserting language to clarify that "[t]he Local Clearing Requirement for each LRZ for each Season will be determined by subtracting Zonal Import Ability and controllable exports from the LRR, as set forth in the Resource Adequacy Business Practices Manual. Controllable exports are exports from MISO resources that have firm capacity commitments to non-MISO load and that may be committed and dispatched by the Transmission Provider during a declared Energy Emergency."

9. Section 68A.7 – Establishing Planning Reserve Margin Requirements

MISO proposes modifying Section 68A.7.a of the Tariff by inserting language to clarify that the PRMR relates to "each Season" and to insert the language that the PRMR "will be determined by multiplying the LSE's forecasted Coincident Peak Demand for each Season, including transmission losses, by (1 + Transmission Provider Region PRM)."

MISO proposes modifying Section 68A.7.b of the Tariff by inserting language to clarify that when an alternative PRM is established by a state "regulatory authority" the Transmission Provider will use the alternate PRM that a state regulatory "authority" has created for the geographic area in which the state has jurisdiction, and the Transmission Provider will convert any state "regulatory authority" provided PRM for a comparable Unforced Capacity basis.

10. Section 68A.8 – Calculation of Transmission Losses

MISO proposes modifying Section 68A.8.a of the Tariff by inserting the phrases "Coincident Peak Demand" and "for each Season" to clarify that the Transmission Provider shall calculate the LBA transmission loss percentages for each Season and that the total transmission loss value (MW) for each LBA will based on Coincident Peak Demand instead of system peak.

11. Section 69A – RAR Process

MISO proposes modifying Section 69A of the Tariff by inserting language to clarify that LSEs and EDCs shall provide forecasted Coincident Peak Demand and Local Resource Zone Peak Demand data "for the Planning Year", the Transmission Provider will calculate each LSE's PRMR "for each Season", and an ACP will be determined through the PRA process for each LRZ and ERZ "for each Season" and the ACP will be used to credit ZRCs and debit LSEs.

12. Section 69A.1 – Load Serving Entities Responsibilities

MISO proposes modifying Section 69A.1 of the Tariff by inserting language into Section 69A.1.b to clarify that the Transmission Provider will use Coincident Peak Demand, Local Resource Zone Peak Demand, and Energy forecasts "for each Season", by removing Section 69A.1.c regarding what happens when the EDC does not provide a procedure for assigning LSE obligations as described in Section 69A.1.b, and by inserting language into the renumbered Section 69A.1.c to clarify that all LSEs shall report to the Transmission Provider whether such LSE will meet their PRMR for each LRZ "for each Season" in which the LSE serves Load.

13. Section 69A.1.1 – Forecasted Demand Identification

MISO proposes modifying Section 69A.1.1 of the Tariff by removing the phrase "annual" throughout and inserting the word a/any/each "Season" throughout.

MISO proposes modifying Section 69A.1.1.b of the Tariff by inserting the phrase "including Demand from any retail demand side management programs" into that section to clarify that "[t]he supplied Coincident Peak Demand and Local Resource Zone Peak Demand forecasts shall include the Demand expected for the forecast time period (*e.g.* the Coincident Peak Demand hour) augmented to include the normal Demand from forecasted demand resources, whether registered or not registered with the Transmission Provider, including Demand from any retail demand side management programs."

MISO proposes modifying Section 69A.1.1.d of the Tariff by removing the phrase "(e.g., annually for Coincident Peak Demand and Local Resource Zone Peak Demand, and monthly for non-coincident peak Demand" from that section to clarify that "[a]ll Coincident Peak Demand and Local Resource Zone Peak Demand forecasts shall reflect a 50% probability that the Demand will not exceed the forecasted Demand for the relevant period.

MISO proposes modifying Section 69A.1.1.e of the Tariff by inserting the clarifying language that "[c]onsistent" with Section 69A.1.2.1, the EDC must provide both the Transmission Provider and the respective LSEs with each retail customer's peak load contribution (PLC) "in each Season", including transmission losses and PRM as determined by the Transmission Provider, in the EDC's service territory by December 15th and by removing the phrase "[i]f an EDC uses the daily peak load default methodology in Section 69A.1.2.1, then the EDC must provide both the Transmission Provider and each of the respective LSEs with the LSE's historic share of the EDC's Coincident Peak Demand, by December 15th."

14. Section 69A.1.1.1 – Accounting for total Demand Forecasts Given Wholesale and Retail Load Switching

MISO proposes modifying Section 69A.1.1.1 of the Tariff by replacing the phrase "June 1 of the next Planning Year" with "the 1st day of each Season in the next Planning Year" in Section 69A.1.1.1.a, replacing the phrase "June 1 of the next Planning Year" with "the 1st day of any Season in the next Planning Year" in Section 69A.1.1.1.b, adding the phrase "for such Season" in Section 69A.1.1.1.b, and adding the phrase "each Season in the" in Section 69A.1.1.1.b.

15. Section 69A.1.2 – Daily Assignment of Coincident Peak Demand Obligations

MISO proposes modifying Section 69A.1.2 of the Tariff by removing Section 69A.1.2.c regarding states that permit retail load switching and satisfy other criteria, removing language from Section 69.A.1.2.b stating "and where the EDC has adopted the preferred default method in Section 69A.1.2.1", and inserting language into Section 69A.1.2.b specifying that that in a state that permits retail load switching the Transmission Provider shall allocate Resource capacity on a daily basis to LSEs through an outlined formula "consistent with Section 69A.1.2.1."

16. Section 69A.1.2.1 – Default Methods

MISO proposes modifying Section 69A.1.2.1 of the Tariff by inserting clarifying language into Section 69A.1.2.1.b that "EDC will assign a Peak Load Contribution ("PLC") value to each retail customer, based on the most recent PLC values derived for each Season from each retail customer's Demand at the time of the Transmission Provider's peak Demand (*i.e.*, the Prior Seasonal Retail Customer Coincident Peak ("PSRCCP"))" and by inserting the phrase "for each Season" to clarify that the PLCs determined by the EDC must equal the PRMR that is calculated

from the forecast Coincident Peak Demand provided by the EDC "for each Season" and that this equality is achieved by multiplying each retail customer's demand at the time of the Transmission Provider's peak Demand during "each Season" prior to the Planning Year by the same adjustment factor. MISO proposes further modifying Section 69A.1.2.1 by replacing "Prior Summer Retail Customer Coincident Peak" with "PRSCCP" throughout the section, by deleting the phrase "[t]he specific methods used by the EDC to compute each retail customer's PLC must be submitted to the Transmission Provider by December 1, and requires approval by, the Transmission Provider" from Section 69A.1.2.1.b, and by deleting Section 69A.1.2.1.c in its entirety because this method is no longer supported by MISO.

17. Section 69A.1.3 – Load Switching

MISO proposes modifying Section 69A.1.3 of the Tariff by removing Section 69A.1.3.b and replacing the phrase "[b]eginning June 1 of each Planning Year" in Section 69A.1.3.a with the phrase "[b]eginning the first Calendar Day of each Season in the Planning Year." and by deleting Section 69A.1.3.b in its entirety because this method is no longer supported by MISO.

18. Section 69A.3 – Planning Resource Requirements

MISO proposes modifying Section 69A.3 of the Tariff by removing language regarding resources with full or partial outages expected to last for ninety days or more of the first one-hundred and twenty days in the Planning Year being precluded from a FRAP or the PRA.

19. Section 69A.3.1 – Capacity Resources

MISO proposes modifying Section 69A.3.1 of the Tariff by inserting the phrase "any applicable Season in the" upcoming Planning Year into the sentence in Section 69A.3.1 "[t]he Transmission Provider will qualify a Capacity Resource for any applicable Season in the upcoming Planning Year, in accordance with processes specified in the BPM for Resource Adequacy" and by replacing the phrase "Capacity Resources cannot be Stored Energy Resources" with the phrase "Stored Energy Resources cannot be Capacity Resources."

20. Section 69A.3.1.a – Generation Resources that are not Dispatchable Intermittent Resources

MISO proposes modifying Section 69A.3.1.a of the Tariff by inserting the phrase "Season in the" into Section 69A.3.1.a.1.b to clarify that it relates to each Season in the Planning Year.

21. Section 69A.3.1.b – Demand Response Resources

MISO proposes modifying Section 69A.3.1.b of the Tariff by inserting language into Sections 69A.3.1.b.1 and 69A.3.1.b.3 to clarify that those sections relate to the applicable "Season" in the Planning Year rather than the Planning Year as a whole.

22. Section 69A.3.1.c – External Resources

MISO proposes modifying Section 69A.3.1.c.1 of the Tariff by inserting the phrases each "Season that the resource will be registered in" and "for each Season that the resource is to be registered in" into Section 69A.3.1.c to clarify that demonstrating GVTC capability relates to each Season and not the Planning Year on an annual basis.

MISO proposes modifying Section 69A.3.1.c.3 of the Tariff by inserting the phrase "applicable Season in the" upcoming Planning Year into Section 69A.3.1.c.3 to clarify that the section relates to the applicable Season and not the upcoming Planning Year.

MISO proposes adding Section 69A.3.1.c.6 of the Tariff stating "Existing Resources that modify their registration, scheduling and market participation in the Energy and Operating Reserves Markets and become pseudo-tied External Resources after September 1, 2022 will be accredited at the lesser of class average SAC in Schedule 53 or the accreditation provisions governing External Resources in section 69A.4.1.b."

23. Section 69A.3.1.d – Use Limited Resources

MISO proposes modifying Section 69A.3.1.d of the Tariff by inserting the phrase "each applicable Season" to clarify that the request that "[a] Use Limited Resource must be able to operate for a minimum set of four (4) consecutive operating Hours across the Transmission Provider's coincident peak for each day in each applicable Season in order to qualify as a Capacity Resource" relates to each Season and not to the Planning Year as a whole.

24. Section 69A.3.1.h – Retirement, Suspension and Replacement of Planning Resources

MISO proposes modifying Section 69A.3.1.h by replacing "Unforced Capacity" with "Seasonal Accredited Capacity" throughout, by removing "or TPRA" throughout, and by inserting language throughout regarding the relevant "Season" of or during the Planning Year. MISO proposes inserting language into Section 69A.3.1.h.a clarifying that "[i]f a Planning Resource for which a Market Participant converts Seasonal Accredited Capacity into ZRCs is Retired or Suspended prior to the end of the Season during the Planning Year in which the ZRCs cleared, such Market Participant must replace the cleared ZRCs with uncleared ZRCs." MISO proposes inserting language into Section 69A.3.1.h.a clarifying that "[i]f a Market Participant does not replace such ZRCs associated with a Retired or Suspended Planning Resource, a Capacity Replacement Non-Compliance Charge will be assessed as determined below in this Section."

MISO proposes modifying Section 69A.3.1.h by inserting language into Section 69A.3.1.h.a clarifying that "[i]f a Planning Resource for which a Market Participant converts Seasonal Accredited Capacity into ZRCs is unable to meet the applicable performance requirements for the cleared ZRCs as described in Section 69A.5 for greater than thirty-one (31) Days in total due to full or partial Generator Planned Outage during the Season of the Planning Year in which the ZRCs cleared, or for Capacity Resources that are the subject to Diversity Contracts for greater than one (1) Month during any Season of the Planning Year in which the ZRCs cleared, such Market Participant must replace the cleared ZRCs with uncleared ZRCs to transfer the performance requirements applicable to the Planning Resource."

MISO further proposes inserting language into Section 69A.3.1.h.a clarifying that "[a]ny combination of cleared or replaced ZRCs that are on full or partial Generator Planned Outage for greater than thirty-one (31) Days in total during a Season, or for any other reason including full or partial Generation Outages that were not planned but were known or could have been reasonably anticipated at the time of the PRA, as set forth in the Market Monitoring and Mitigation Business Practices Manual, or unavailable because subject to a Diversity Contract that is not available for greater than one (1) Month during a Season, will be assessed a Capacity Replacement Non-

Compliance Charge. If a Planning Resource for which a Market Participant converts Seasonal Accredited Capacity into ZRCs is unable to meet the applicable performance requirements for the cleared ZRCs as described in Sections 69A.3.3.1 and 69A.5 due to a Catastrophic Generator Outage any time during the Season of the Planning Year in which the ZRCs cleared such Market Participant may replace the cleared ZRCs with uncleared ZRCs to transfer the performance requirements applicable to the Planning Resource. A Planning Resource may not transfer its performance requirements by replacing the cleared ZRCs with uncleared ZRCs other than in the case of suspension, retirement, Catastrophic Generator Outage or full or partial Generator Planned Outages that may exceed thirty-one (31) Days in the Season as discussed immediately above."

MISO proposes modifying Section 69A.3.1.h by inserting language into Section 69A.3.1.h.a clarifying that "ZRC replacement shall have no impact on settlements from the PRA and FRAPs, including any assessed Capacity Replacement Non-Compliance Charges." MISO proposes further modifying Section 69A.3.1.h by creating Section 69A.3.1.h.b with language specifying that Capacity Replacement Non-Compliance Charges will be assessed for the number of days the Market Participant had an obligation to replace and failed to do so and calculated based on the amount of ZRCs that failed to be replaced multiplied by the sum of the ACP and the daily CONE Value which will be based on the LRZ where the Planning Resource cleared those ZRCs and that revenues from such charges received by the Transmission Provider will be distributed to LSEs that have met their PRMR during the applicable Season of the Planning Year on a *pro rata* basis based upon the LSEs share of total PRMR for the Transmission Provider Region.

25. Section 69A.3.2 – Energy Efficiency Resources (EE Resource)

MISO proposes modifying Section 69A.3.2 of the Tariff by replacing "annually" with "for each Season" to clarify that "[a]n EE Resource can qualify as a Planning Resource for ZRCs for each Season for up to four (4) Planning Years immediately following the EE Resource's initial qualification provided that the energy efficiency measures are fully implemented prior to each Planning Year."

26. Section 69A.3.3 – Load Modifying Resource

MISO proposes modifying Section 69A.3.3 of the Tariff by removing "TPRA", inserting the phrase "for a Season" to describe that all LMRs that are cleared in the PRA or were submitted in a FRAP for a Season needing to be available for use in the event of an Emergency as declared by the Transmission Provider, inserting the phrase "the applicable Season in" in the sentence "[i]n accordance with the BPM for Resource Adequacy, the Transmission Provider will qualify an LMR for the applicable Season in the upcoming Planning Year", and replacing the phrase coincident peak with "Coincident Peak Demand."

27. Section 69A.3.3.1 – Deployment Procedures for LMR

MISO proposes modifying Section 69A.3.3.1 of the Tariff by inserting the language "minimum" and "for the applicable Season" into the sentence "[a] Market Participant that acknowledge Scheduling Instructions for its LMR(s) as required by the BPM for Resource Adequacy will receive credit for one (1) of the minimum deployments or interruptions required for the LMR for the applicable Season whether or not an emergency is declared" and by inserting the language that an LMR which does not perform consistent with the Market Participant's

response to its Scheduling Instructions will not receive credit "as one (1) of the minimum deployments or interruptions required for such resource for the applicable Season."

28. Section 69A.3.4 – Demand Resources (DR)

MISO proposes modifying Section 69A.3.4 of the Tariff by inserting the word "authority" into the phrase "applicable state regulatory authority" and by inserting the phrase "each Season in" into the sentence "[i]n accordance with the BPM for Resource Adequacy, the Transmission Provider will qualify a DR for each Season in the upcoming Planning Year."

29. Section 69A.3.5 – Demand Resource Eligibility

MISO proposes modifying Section 69A.3.5 by inserting language into Section 69A.3.5.a clarifying that a grouping of smaller resources aggregated together than can reduce an LSE's Coincident Peak Demand "for the applicable Season" may qualify in meeting the requirement that a Demand Resource must be equal to or greater than 100 kW.

MISO proposes modifying Section 69A.3.5 by inserting language into Section 69A.3.5.b clarifying that beginning in the 2023/2024 Planning Year, a Demand Resource must have a notification time requirement "less than or equal to six (6) hours to receive credit as a Planning Resource in the applicable Seasons."

MISO proposes modifying Section 69A.3.5 by inserting language into Section 69A.3.5.e clarifying that the prior requirements of that section will apply to the 2022/2023 Planning Year but that for the 2023/2024 Planning Year a Demand Resource must have a notification time equal to or less than "six (6) hours and be capable of being interrupted for: (i) at least the first five (5) times requested in the Summer Season; and, at least the first five (5) times in the Winter Season; and, (iii) for at least the first three (3) times requested in the Spring Season; and (iv) for at least the first three (3) times in the Fall Season, based on their physical availability when called upon by the Transmission Provider for an Emergency during any applicable Season in the Planning Year for which the Demand Resource receives credit as a Planning Resource." MISO proposes modifying Section 69A.3.5.e by removing the provisions related to limitations due to contractual obligations and the requirement that the Demand Resource's availability must include the entire Summer Season.

MISO proposes modifying Section 69A.3.5 by inserting language into Section 69A.3.5.j that a Demand Resource for which a real power test is conducted will receive credit as one (1) of the "minimum" deployments or interruptions required for such Resource for the "applicable Season of the" Planning Year in which such a test occurs.

30. Section 69A.3.6 – Behind the Meter Generation Eligibility

MISO proposes modifying Section 69A.3.6 by inserting language into Section 69A.3.6.1 clarifying that the Transmission Provider will qualify as BTMG for the "applicable Season in the" upcoming Planning Year.

MISO proposes modifying Section 69A.3.6 by inserting language into Section 69A.3.6.1.b clarifying that a BTMG can request accreditation for such BTMG - in part - by demonstrating GVTC capability for "applicable Season in" each Planning Year on an annual basis.

MISO proposes modifying Section 69A.3.6 by removing language in Section 69A.3.6.1.d regarding limitations due to contractual obligations that are more restrictive than the physical limitations of the BTMG in place as of December 21, 2018.

MISO proposes modifying Section 69A.3.6 by inserting language into Section 69A.3.6.1.f clarifying that a BTMG can request accreditation for such BTMG - in part – by demonstrating that the BTMG is capable of being deployed at the accredited MW level for: (i) at least the first five (5) times requested in the Summer Season; and, (ii) at least the first five times requested in the Winter Season; and (iii) at least the first three (3) times requested in the Spring Season; and (iv) at least the first three (3) times requested in the Fall Season", by removing language in Section 69A.3.6.1.f that "[t]his availability must include at least the entire Summer Season", and by removing language in Section 69A.3.6.1.f regarding limitations due to contractual obligations that are more restrictive than the physical limitations of the BTMG in place as of December 21, 2018.

31. Section 69A.4 – Planning Resource Capacity Values

MISO proposes modifying Section 69A.4 of the Tariff by inserting language clarifying that Capacity Resources will be given "a capacity value for each applicable Season based on the Seasonal Accredited Capacity calculation applicable to its Resource type."

32. Section 69A.4.1 – Seasonal Accredited Capacity of Capacity Resources

MISO proposes modifying Section 69A.4.1 of the Tariff by replacing "Unforced Capacity" with "Seasonal Accredited Capacity" throughout the section.

MISO proposes modifying Section 69A.4.1.a of the Tariff by inserting clarifying language that "[t]he Seasonal Accredited Capacity for a Capacity Resource that is a Generation Resource, but not a Dispatchable Intermittent Resource, Intermittent Generation, Electric Storage Resource, External Resource or Use Limited Resource, is based on an evaluation of the type and volume of the interconnection service, GVTC value, and Real-Time offered availability of such Generation Resource for each Season as set forth in Schedule 53" and by removing language regarding resources that are not required to report generator availability.

MISO proposes modifying Section 69A.4.1.b of the Tariff by inserting clarifying language that "[t]he Seasonal Accredited Capacity for a Capacity Resource that is an External Resource, but not a Dispatchable Intermittent Resource, Intermittent Generation or Use Limited Resource, is based on the GVTC value and $XEFOR_d$ values of such External Resource for each Season."

MISO proposes modifying Section 69A.4.1.c of the Tariff by inserting clarifying language that "[t]he Transmission Provider will determine the appropriate capacity value for DRR that qualifies as a Capacity Resource and that interrupts or controls Load, based upon historical performance and availability, for each Season, as set forth in Schedule 53" and by removing language regarding resources that are not required to report generator availability.

MISO proposes modifying Section 69A.4.1.d of the Tariff by inserting clarifying language that "[t]he Transmission Provider will determine the Seasonal Accredited Capacity for each DRR that qualifies as a Capacity Resource and that is a behind the meter generation facility based on an evaluation of the GVTC value and Real-Time offered availability for such behind the meter generation facility for each Season as set forth in Schedule 53."

MISO proposes modifying Section 69A.1.e of the Tariff by inserting the phrase "or Use Limited Resource" into that section.

MISO proposes adding Section 69A.1.h of the Tariff stating that "[t]he Seasonal Accredited Capacity for a Capacity Resource that is a Use Limited Resource will be determined by the Transmission Provider based on the type and volume of interconnection service, the GVTC and $XEFOR_d$ values of such Use Limited Resource in accordance with the BPM for Resource Adequacy."

33. Section 69A.4.2 – Seasonal Accredited Capacity of Demand Resources

MISO proposes modifying Section 69A.4.2 of the Tariff by replacing "Unforced Capacity" with "Seasonal Accredited Capacity."

34. Section 69A.4.3 – Seasonal Accredited Capacity of Behind the Meter Generation

MISO proposes modifying Section 69A.4.3 of the Tariff by replacing "Unforced Capacity" with "Seasonal Accredited Capacity" when stating that "[t]he Transmission Provider will determine the Seasonal Accredited Capacity for each BTMG that qualifies as an LMR as set forth in the Resource Adequacy Business Practices Manual" and when stating that "[i]f such BTMG is interconnected to the Transmission System, the Transmission Provider will consider the type and volume of interconnection service when determining Seasonal Accredited Capacity." MISO proposes modifying Section 69A.4.3 of the Tariff by removing the phrase that the Transmission Provider will determine capacity for each BTMG that qualifies as an LMR "based on an evaluation of the GVTC value and $XEFOR_d$ values of such BTMG."

35. Section 69A.4.4 – EE Resources

MISO proposes modifying Section 69A.4.4 of the Tariff by replacing "Unforced Capacity" with "Seasonal Accredited Capacity" when describing how capacity will be determined for a qualified EE Resource by the Transmission Provider.

36. Section 69A.4.5 – Attributes of ZRCs

MISO proposes modifying Section 69A.4.5 of the Tariff by replacing "Unforced Capacity" with "Seasonal Accredited Capacity" throughout that section and by removing language related to the calculation of the convertible Unforced Capacity. MISO proposes further modifying Section 69A.4.5 of the Tariff to include language in Section 69A.4.5.A regarding the allocation of Seasonal Accredited Capacity and the calculation of Seasonal Accredited Capacity value.

37. Section 69A.5 – Capacity Resource Must Offer and Performance Requirements

MISO proposes modifying Section 69A.5 of the Tariff by replacing the phrase "Unforced Capacity" with "Seasonal Accredited Capacity" throughout the section, removing the word "TPRA" from the section, inserting language regarding a/any/each "Season" into the section to clarify that the Capacity Resource Must Offer and Performance Requirements relate to each Season in the Planning Year and not to the Planning Year as a whole.

MISO proposes further modifying Section 69A.5 of the Tariff by inserting language into Section 69A.5.a clarifying that Market Participants that convert Seasonal Accredited Capacity

from Capacity Resources into ZRCs that clear in a Season in the PRA or are used in a FRAP (and that do not replace such ZRCs in accordance with Section 69A.3.1.h), "including Capacity Resources that are the subject of Diversity Contracts," must submit Self-Schedules or Offers for Energy, and Contingency Reserve if qualified, and offers for Short-Term Reserve if qualify, for the Installed Capacity value of the Capacity Resources converted to ZRCS "and clear in a Season in the PRA or used in a FRAP" for each Hour of each Day during the applicable Season in the Planning Year, in the Day-Ahead Energy Market and all pre Day-Ahead and the first post Day-Ahead Reliability Assessment Commitment process."

MISO proposes modifying Section 69A.5.a by adding the sentence "[a]ny such Capacity Resource with full or partial Generator Planned Outages that exceeds thirty-one (31) Days during any Season will be deemed not to have met its performance requirement for any days greater than thirty-one (31) days and must replace ZRCs in accordance with Section 69A.3.1.h, provided that Capacity Resources subject to Diversity Contracts that are unavailable for greater than one Month during any Season will be deemed not to have met its performance requirement and will be subject to the ZRC replacement provisions set forth in Section 69A.3.1.h."

MISO proposes modifying Section 69A.5.b by inserting language clarifying that "[i]f a Capacity Resource that has ZRCs cleared in the PRA during any Season or is used in a FRAP during any Season is capable of performing but fails to perform when called upon by the Transmission Provider for an Emergency, the Transmission Provider shall assess the owner of such Capacity Resource the costs that were otherwise incurred to replace the energy from the deficient Capacity Resource at the time that the Capacity Resource is called upon by the Transmission Provider and does not respond in full or in part, for each day of non-performance of such Capacity Resource, provided that the planned or forced outage of the Capacity Resource is not properly reported in the Transmission Provider's Outage Scheduler, as set forth in the Business Practices Manual for Outage Operations."

38. Section 69A.6.3 – Facilitation of a Bilateral Capacity Bulletin Board

MISO proposes modifying Section 69A.6.3 of the Tariff by replacing "Unforced Capacity" with "Seasonal Accredited Capacity" with respect to the Transmission Provider's electronic bulletin board platform that may be used by Market Participants.

39. Section 69A.7 – Planning Resource Auction

MISO proposes modifying Section 69A.7 of the Tariff by replacing "ten (10)" with "twenty (20)" with respect to the number of Business Days after the last Business Day in March when the Transmission Provider will conduct a RA to determine the ACP in each LRZ and ERZ.

40. Section 69A.7.1 – PRA Procedures

MISO proposes modifying Section 69A.7.1 of the Tariff by replacing "Unforced Capacity" with "Seasonal Accredited Capacity" throughout the section, removing "TPRA", clarifying that "[t]he price associated with these ZRC Offers cannot exceed the annual CONE value divided by the number of days in the Season for the LRZ where the ZRC is represented", inserting the sentence in Section 69A.7.1.x that "[t]he maximum Auction Clearing Price will be based on the annual CONE and the number of Seasons deficient in the Planning Resource Auction", replacing "tenth" Business Day in Section 69A.7.1.xi with "twentieth" Business Day, specifying in Section 69A.7.1.c.i that "[a]fter a maximum of two (2) successive iterations per Season to address network

violations, the auction clearing iteration with the fewest megawatts of network violations will be deemed as the final auction result", and adding language regarding "each Season" throughout.

MISO proposes modifying Section 69A.7.1.c.x by inserting language clarifying that "[t]he final Auction Clearing Price (ACP) for a LRZ, group of LRZs, or SRRZ with Seasons in ZRC Shortage Conditions will be set as the amount obtained by dividing the applicable LRZ's annual CONE value by the number of days in Seasons which the LRZ, group of LRZs, or a SRRZ were in ZRC Shortage Conditions and Near ZRC Shortage Conditions in the Planning Resource Auction. The final Auction Clearing Price (ACP) for a LRZ, group of LRZs, or SRRZ with Seasons in Near ZRC Shortage Conditions will be set as the minimum of: (a) the original ACP as determined in section 69A.7.1.c.(v) or section 69A.7.1.c.(vi) as applicable; or (b) the amount obtained by dividing the applicable LRZ's annual CONE value by the number of days in Seasons which the LRZ, group of LRZs, or SRRZ were in ZRC Shortage Conditions and Near ZRC Shortage Conditions in the Planning Resource Auction."

41. Section 69A.7.3 – Uncleared ZRCs

MISO proposes modifying Section 69A.7.3 of the Tariff by replacing "Unforced Capacity" with "Seasonal Accredited Capacity" and removing "TPRA."

42. Section 69A.7.6 – PRA Settlement

MISO proposes modifying Section 69A.7.6 of the Tariff by inserting language into Section 69A.7.6.a to clarify that "[t]he reduced compensation will be based on the total number of days the capacity from the Diversity Contract is dedicated to demand in the Transmission Provider Region in each Season divided by the total number of days in the Season."

MISO proposes adding Section 69A.7.6.d specifying that "[f]or instances where a LRZ, group of LRZs, or SRRZ clears under ZRC Shortage Conditions or ZRC Near-Shortage Conditions in more than one Season in a Planning Resource Auction and final ACPs are adjusted per Section 69A.7.1.c.(x), certain cleared ZRC Offers may exceed the final ACPS" and clarifying the circumstances under which certain ZRCs may be eligible for a ZRC Offer Revenue Sufficiency Credit and how that credit would be calculated and allocated.

MISO proposes adding Section 69A.7.6.e specifying that ZRC Offer Revenue Sufficiency Charges "will be assessed as the sum of all ZRC Offer Revenue Sufficiency Credits for a Season distributed to Market Participants representing LSEs in an LRZ, group of LRZs, or SRRZ clearing under ZRC Shortage Conditions or Near ZRC Shortage Conditions on a *pro rata* basis, based upon their respective LSE's share of total PRMR in the appropriate LRZ, group of LRZs, or SRRZ."

43. Section 69A.7.9 – Installed Capacity (ICAP) Deferral Requirements and Charges

MISO proposes modifying Section 69A.7.9 by inserting language to clarify that the ICAP Deferral Notice, ICAP Deferral Non-Compliance Charges, and Distribution of ICAP Deferral Non-Compliance Charges are based on the "Season" and not the "Planning Year."

44. Section 69A.9 – Opting out of the Planning Resource Auction

MISO proposes modifying Sections 69A.9.a of the Tariff by inserting language clarifying that an LSE electing to opt out of the PRA "for any Season" can continue to use its existing

resource planning processes to meet their PRMR by providing the Transmission Provider with a FRAP for each LRZ which must include the forecasted Coincident Peak Demand for "each Season" and must also identify its load ratio share for "each Season." MISO proposes modifying Sections 69A.9.b of the Tariff by inserting language clarifying and that an LSE that submits a FRAP for a LRZ will be able to opt out of the PRA for such "Season" for such LRZ to the extent that the LSE's ZRC's satisfy the LSE's PRMR "for the applicable Season(s)." MISO proposes to clarify the provisions relating to the Capacity Deficiency Charge by modifying Section 69A.9.c of the Tariff by removing the phrase "[a]n LSE that is capacity deficient will be assessed a Capacity Deficiency Charge in accordance with Section 69A.10."

45. Section 69A.10 – Capacity Deficiency Charge

MISO proposes modifying Section 69A.10 of the Tariff by inserting language clarifying that the Transmission Provider will impose a Capacity Deficiency Charge on an LSE that has "provided notification prior to the Planning Resource Auction that they will meet their PRMR in part or in whole for the Planning Year by paying the Capacity Deficiency Charge." MISO proposes modifying further language clarifying that "[t]he CONE value for the LRZ(s) where the LSE has provided notice it will be meeting its PRMR by paying the Capacity Deficiency Charge for the Planning Year will be multiplied by 2.748 times the PRMR volume indicated by the LSE for Planning Year."

MISO proposes modifying Section 69A.10.b to clarify that the distribution of Capacity Deficiency Charge revenues will not be distributed to any Market Participant representing an LSE that has provided notice it will be meeting its PRMR by paying the Capacity Deficiency Charge, and specifying details of the distribution calculation.

I. Schedule 53 – Seasonal Accredited Capacity Calculation

1. Section I – General

MISO proposes creating Schedule 53 Section I of the Tariff by inserting language specifying that "Seasonal Accredited Capacity (SAC) for a Capacity Resource that is a DRR or Generation Resource but not a Dispatchable Intermittent Resource, Intermittent Generation Electric Storage Resource, or Use Limited Resource will be determined pursuant to this Schedule 53." MISO proposes inserting language into Section I clarifying that "[a] two-tiered weighting structure is used to calculate Seasonal Accredited Capacity for such Resource".

2. Section II – Tier 1 and Tier 2 Planned Outage Exemptions Requirements

MISO proposes creating Schedule 53 Section II of the Tariff by adding Section II.A-B to specify the requirements for Tier I and Tier 2 outage exemptions for Generator Planned Outages after September 1, 2022. The language in Section II.A specifies the Tier 2 Planned Outage exemption requirements. The language in Section II.B specifies the Tier 1 Planned Outage exemption requirements. MISO further proposes that "Generator Planned Outages scheduled to begin before September 1, 2022 will be granted a Tier 2 exemption based on Section 38.2.5.g.ix., and as set forth in the Business Practices Manual for Resource Adequacy."

Section II.C will contain language specifying that under the No Harm Test "[o]utages submitted between 14 to 30 days of start date will be evaluated for final approval and exemption status together. The No Harm Test includes, but is not limited to, outage approval, compliance

with all applicable operation guides, review of possible conflicting outages or system conditions, and system capacity (Maintenance Margin, Multiday Operational Margin, 30-day margin). It also includes the criteria outlined in the Business Practices Manual for Generator Outage."

3. Section III – Resource Adequacy Hours

MISO proposes creating Schedule 53 Section III of the Tariff by inserting language specifying that "Resource Adequacy (RA) Hours represent the periods of highest risk and greatest need during a Season and throughout the year. They include hours during Maximum Generation Emergency declarations and the hours when the operating margin, a measure of available supply capacity above demand and reserve requirements, is at its lowest." "Resource Adequacy Hours will be identified based on an evaluation of the three (3) most recent completed years using the period September 1st and ending August 31st which will be used to determine Resource Adequacy Hours for each Season (Seasonal RA Hours) and for each annual period (Annual RA Hours)."

MISO proposes inserting language into Section III.A describing how Seasonal RA Hours will be determined, inserting language into Section III.B describing how Annual RA Hours will be determined, and inserting language into Section III.C describing how Seasonal Non-RA Hours will be determined. MISO proposes inserting language into Section III.D specifying that Tier 1 exemptions apply only to Non-RA Hours whereas Tier 2 exemptions apply to any Hours referenced in Schedule 53 and that Tier 1 and Tier 2 outage exemption requirements are set forth in Section II of Schedule 53.

4. Section IV – Operating Margin Calculation

MISO proposes creating Schedule 53 Section IV of the Tariff by inserting language specifying that "[t]he Operating Margin is determined using historical information to identify Seasonal RA Hours and Annual RA Hours within the three (3) most recent periods beginning September 1st and ending August 31st." MISO proposes inserting language into Section IV defining the equation used to calculate Operating Margin.

5. Section V –Seasonal Accredited Capacity Calculation

MISO proposes creating Schedule 53 Section V of the Tariff by inserting language into Section V.A-C specifying that Annual Average Offered Capacity, Tier 1 Intermediate SAC (ISAC), and Tier 2 ISAC will all be calculated in part utilizing either the Hourly Emergency Maximum Limit or the Targeted Demand Reduction Level for DRR-1. The proposed language specifies that for any Annual RA Hour or Seasonal RA Hour where a Resource is offline and the sum of the Start-Up Time and Start-Up Notification Time Offers exceeds 24 hours, the Resource "will have its Hourly Emergency Maximum Limit, or Targeted Demand Reduction Level for DRR-1, set to zero (0)."

MISO proposes inserting language into Section V.D specifying that "the Hourly Emergency Maximum Limit, or Targeted Demand Reduction Level for DDR-1, will be capped at the currently effective GVTC value of the Resource and whether or not a Resource was only committed for a portion of its ICAP due to partial clearing will not impact the offers considered in the accreditation calculations.

MISO proposes inserting language into Section V.E specifying that "the historical values for Hourly Emergency Maximum Limit, or Targeted Demand Reduction Level for DDR-1, will

be increased for those hours prior to the upgrade going into effect to account for the upgrade as set forth in the Business Practices Manual for Resource Adequacy."

MISO proposes inserting language into Section V.F specifying that "RA Hours will receive a greater weight than non-RA hours", inserting language into Section V.G defining the equation used to calculate ISAC, inserting language into Section V.H defining the equation used to calculate "[a] system-wide conversion ratio", and inserting language into Section V.I defining the equation used to calculate SAC.

6. Section VI – New Resources or Resources with Insufficient Performance Data

MISO proposes creating Schedule 53 Section VI of the Tariff by inserting language into specifying that "New Resources or existing Resources that do not have at least 60 days of Real-Time offered availability when designated for RAR over the last three (3) years for each Season (Summer, Fall, Winter, Spring) will have a SAC based on the Class Average SAC to ICAP Ratio for its Resource type." MISO proposes inserting language specifying that "Resources on a Catastrophic Generator Outage during a Season they are designated for RAR may elect to use a SAC based on the Class Average SAC or ICAP Ratio for its Resource type the next time it is accredited for that Season provided all of its committed ZRCs were replaced with uncleared ZRCs and that it has successfully returned from the Catastrophic Generator Outage."

VII. RESPONSE TO KEY STAKEHOLDER ISSUES

As described above, MISO has engaged in substantial stakeholder discussions relating to the development of the Resource Adequacy enhancements proposed in this filing. As part of those discussions, stakeholders have raised various issues that have been documented, vetted and, as appropriate, incorporated in this filing. MISO also has determined that a number of stakeholder suggested modifications are either outside the scope of this filing and/or should be addressed through alternative means. Following is a list of key issues raised by stakeholders and MISO's responses. It should be noted that this list is not exhaustive, but MISO believes represents the major issues presented.

- *Implementation of seasonal reforms only* – Stakeholders have requested that MISO implement only the proposed PRA seasonal reforms separate from the proposed accreditation reforms. Moreover, stakeholders have requested that MISO delay filing and implementation of any accreditation changes to allow the opportunity for additional discussions.

As discussed with stakeholders during the RASC presentation on June 9, 2020, in order to meet future reliability risks, there needs to be an alignment between Resource Adequacy Requirements and Resource accreditation. To adjust requirements on a seasonal basis without making corresponding adjustments to a resource's seasonal accreditation could potentially create more risk for the MISO system. As further described in the Testimony of Mr. Wright, by transitioning to a seasonal construct only, requirements may decrease and true availability of resources may be overstated and adversely impact system reliability.[124] Since 2016, over 60% of

[124] Wright at 2-3.

MaxGen events have occurred outside of the Summer. Creating a scenario where requirements are lower when considered on a seasonal basis and resource accreditation continues to be based on the current method with only muted and weak linkages to actual resource availability during times of highest need could exacerbate the risk of capacity shortfalls. Further, the proposed seasonal construct facilitates stakeholder preferences for increased seasonal outages, possibly lowering excess reserve margins. In light of this, MISO must have higher confidence in the availability of the resources that do clear for any given Season, as accomplished through the proposed improvements to accreditation and outage coordination processes.

Furthermore, as detailed in the Testimonies of Messrs. Wright, McFarlane, and Smith, the proposed seasonal and accreditation changes are urgently required at this time in response the Reliability Imperative. MISO cannot afford to wait any longer to implement this integrated package of changes needed to enhance its Resource Adequacy construct and to help ensure reliability in the MISO Region.

- *Determination of Resource Adequacy Hours* – Stakeholders have argued that MISO has not adequately justified the proposed use of 65 RA Hours per Season (which, as described above, is based upon 3% of the hours during each Season). In addition, stakeholders have objected to the manner in which MISO proposes to "backfill" seasonal RA Hours with AAOC hours.

As described above, RA Hours represent the periods of highest risk and greatest need during a Season and throughout the year. They include emergency declaration periods and the hours when the operating margin, a measure of available supply capacity above demand and reserve requirements, is at its lowest. MISO's analysis indicates that the tightest 3 percent of hours align with emergency event occurrence is reasonable. Further, MISO examined the operating margins during the times of highest risk, which also informed the selection of 3 percent.

As proposed, RA Hours will be determined seasonally, based on emergency events, the tightest 3 percent of operating margin hours, and a maximum operating margin threshold established at 25 percent. RA Hours will be used to determine each resource availability for calculating its seasonal accreditation. To ensure that MISO includes all appropriate RA Hours, the total number of RA Hours in a Season can exceed the minimum target (*i.e.,* 65 hours) when a higher number of hours during declared system or sub-regional emergencies occurs. Moreover, in some Seasons (or for resources with Tier 2 planned outage exemptions for seasonal RA Hours) there may not be 65 hours during the Season to use for the Schedule 53 calculations. The proposal strikes a balance between identifying RA Hours that represent the times of high risk and having sufficient RA Hour sample sizes to avoid undue volatility. MISO's proposal supplements the seasonal RA Hours for a resource with the average offers over the tightest operating conditions during the same Planning Year where it was not on an exempt outage.

For any Season that a resource lacks sufficient hours, set at 65 hours minimum, the accreditation will augment the deficient number of hours less than 65 for that Resource with its AAOC, which is determined over the tightest 3 percent of hours during the year, or 263 hours. Certain stakeholders have expressed concern that the availability of a resource in one Season may not accurately represent the availability of that resource during a different Season. MISO believes

that the use of RA Hour availability during the other tight margin hours in the Planning Year is a reasonable substitute in the determination of accreditation as it reflects actual resource availability during tight conditions throughout the year. Some stakeholders suggested using all-hours availability during the Season to "backfill" RA Hours would be more appropriate. However, MISO believes this approach would inappropriately dilute assessments of a Resource's availability during tight conditions because it effectively substitutes the resource's availability during non-tight conditions.

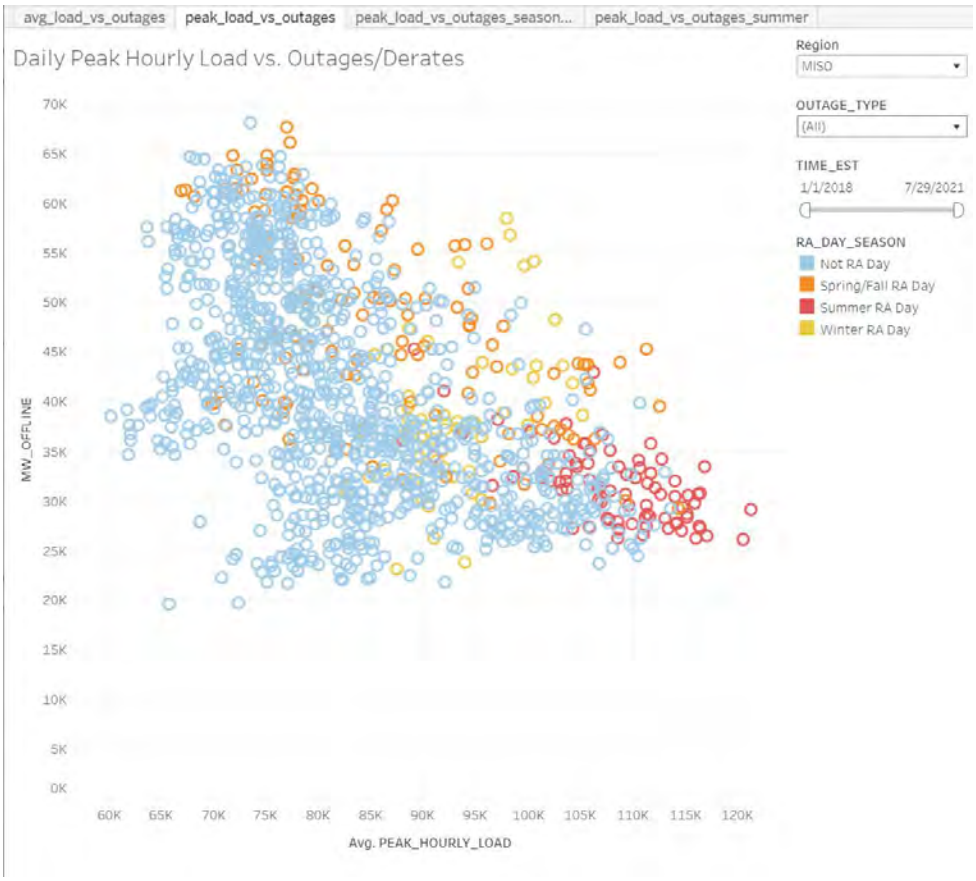
- *Schedule 53 Tier weighting and volatility of requirements* – Stakeholders have asked for further support regarding the basis for the proposed 20/80 weighting of Tier 1 vs. Tier 2 hours in Schedule 53. Stakeholders also requested that MISO phase in the proposed Tier 1 vs. Tier 2 weighting over a period of time in order to provide stakeholders the opportunity to adjust their planning and operations. In addition, stakeholders have raised concerns about the potential volatility of the proposed changes as they may impact Resource accreditation year over year.

The initial Resource accreditation proposal shared with Stakeholders in January of 2021 essentially weighted RA Hours (*i.e.,* Tier 2 hours) at 100% towards a Resource's offered availability. This solely emphasized the importance of resource availability during the tightest operating conditions. In a recent State of the Market Report, MISO's IMM recommended a similar approach to align a resource's auction value with its true contribution to reliability.[125] Seasonal requirements also necessitate accreditation align with actual expectations during times of highest risk during each Season. In response to the initial proposal, stakeholders requested a method that also recognized a resource's reliability contribution during non-RA Hours, basing some portion of accreditation on general availability.

MISO recognizes the value of general availability, however, as the IMM's analysis of the current UCAP method illustrates, it does not adequately reflect availability during times of highest risk and the true reliability value. As a result, MISO responded by developing the two-tier accreditation proposal, which sets the Tier 1 (*i.e,* non-RA Hours) weighting to 20%, acknowledging a Resource's general availability and its contribution to avoiding capacity emergency events. Importantly, however, MISO sets the Tier 2 (RA Hour) weighting at 80% to emphasize Resource reliability contribution during times of greatest reliability needs. The data plot below illustrates how RA Hours occur on days with high peak load, high outage rates or a combination of both, and supports the rationale for the heavier weighting of Tier 2 hours in resource accreditation.

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125 *See* fn. 40 *supra*.



To address stakeholder requests to phase in the proposed Schedule 53-tiered weighting, MISO has adopted a three-year phased in approach proposed by stakeholders. Beginning in PY 2023/2024, the Tier 1/Tier 2 weighting will be 40/60, increasing to 30/70 in PY 2024/2025, and ending up with the full adoption of the 20/80 weighting in PY 2025/2026. Adopting this transition will generally lessen the impact of these accreditation changes in the near-term while providing more time for stakeholders to adjust planning and operations before the entire weighting takes effect.

With respect to stakeholder concerns regarding volatility, analysis of Market Participant level, zonal and MISO-wide results indicate reasonably low levels of volatility and appropriate relative accreditation based on resource performance during times of need.[126] The key principle of the proposed accreditation is to determine the relative accredited values among different resources to align with their actual performance during times of needs while maintaining the overall supply and demand balance at the footprint level. By design, more resource level volatility with the proposed accreditation methodology would be expected, but in aggregate the proposal leads to very little volatility at the MISO Region-wide level from year to year, especially over time. As

126 *See* Resource Adequacy Reforms, MISO RASC (September 2021) at 6.

presented at the September RASC meeting, the proposal leads to, less than 2% volatility at MISO Region-wide level, in part as a result of the application of the UCAP to SAC ratio.[127]

- *Generator Planned Outage exemptions* – Stakeholders have argued that MISO's proposal does not offer sufficient flexibility to permit Generator Planned Outages without exposing them to potential accreditation impacts.

In its initial proposal, MISO was outage agnostic, choosing to base availability solely on availability during RA Hours with no exemption for effective coordination regarding Generator Planned Outages. This also aligned with IMM State of the Market recommendations regarding availability-based accreditation, discussed above. Stakeholders requested that MISO consider enhancements to the RAN Phase 1 outage exemption process for incorporation in the proposal, as those processes involved significant stakeholder engagement in the past and have provided reliability benefits. MISO agreed with the stakeholder suggestion, noting improved outage coordination was one of the goals of these reforms. However, MISO also cautioned that any exemptions must be strongly aligned with effective coordination processes to ensure reliable outcomes and incent coordination. If all planned outages receive exemptions, resources will not be deterred from scheduling outages during the tightest operating conditions.

Ultimately, in response to stakeholder feedback, MISO built upon the RAN Phase 1 outage process when developing its proposal to exempt certain outages under the revised accreditation proposal. As set forth in Schedule 53, the exemption rules specifically consider whether an outage is submitted 120 days or more in advance, whether there is a positive Maintenance Margin for the duration of the outage, and whether the outage is scheduled to start less than 120 days from the end of a previous outage. MISO believes the proposed exemption rules reasonably accommodate the needs of stakeholders to take appropriate planned outages with the need for MISO to ensure that resources will be available during times of greatest risk. Moreover, the proposed rules appropriately reflect a resource's unavailability in its accredited value, whether such unavailability is a result of planned, forced or maintenance outages that put the system at increased risk.

- *Capacity replacement requirement* – Stakeholders have suggested that the capacity replacement requirement, and associated Capacity Replacement Non-Compliance Charge, impose unfair obligations. Some stakeholders specifically object to the requirement that they replace resources that are unavailable for more than 31 days, and that MISO is imposing a charge for failure to replace.

MISO believes the proposed replacement requirements are reasonable to ensure that resources that clear for a Season will be available to contribute to reliability when committed. As MISO shifts from an annual to a seasonal construct, it is reasonable to require replacement of resources that are unavailable more than 31 days out of an approximately 91-day Season as a result of Generator Planned Outages. The proposed replacement requirement also is consistent with the existing Tariff requirement that resources that are not available for 90 out of the 120 days preceding the PRA are not eligible to participate in the PRA for that Planning Year.

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127 *Id.*

Moreover, a resource contemplating a Generator Planned Outage in excess of 31 days can request approval from the IMM prior to the PRA for exclusion from physical withholding market mitigation measures, and if approved, not offer the resource into the PRA. If such a request is approved, the IMM has indicated a resource could still offer at its discretion and would be able to offer the excluded portion of the resource at any price up to the offer cap without the need to obtain a facility specific Reference Level. MISO has added the IMM's recommended provisions in section 64.1.1.g.xi of Module D.

The Capacity Replacement Non-Compliance Charge ensures that Market Participants whose resources clear the PRA for a Season are sufficiently available for a majority of the Season to contribute to reliability. Currently, there is no specified financial non-compliance provisions for failure to replace a resource that clears the PRA and subsequently retires or suspends. Increased flexibility for Market Participants to choose whether to participate in a Season requires financial consequences for the failure to replace unavailable units. The proposed Capacity Replacement Non-Compliance Charge reasonably addresses this need. In addition, the proposal generally indicates lower requirements for non-Summer Seasons compared to today's construct. Accordingly, it is reasonable to impose a financial non-compliance charge to incent availability of sufficient resources to meet the lower requirements. As noted above, MISO is also adding provisions allowing the replacement of resources that have experienced catastrophic outages, enabling such resources to maintain class average accreditation upon return to service.

- *Need for additional analysis* – Stakeholders have argued that MISO has not provided sufficiently detailed analysis for them to determine the impact of the proposed changes on their specific resources.

Contrary to some stakeholder assertions, MISO has provided stakeholders many elements of required analysis, including: seasonal SAC values and requirements at the portfolio level (highlighting the changes relative to their current requirements); unit-level SAC values on a seasonal basis; and, extensive and detailed data for at least one individual resource, for each stakeholder requesting such data, including all the inputs and calculations necessary to allow stakeholders to independently validate how MISO derived the SAC values for that resource. This information was provided more than once for those stakeholders requesting this data over the course of the conceptual design.

MISO also provided preliminary and revised impact analysis results at the system-wide and zonal levels at multiple RASC stakeholder meetings over the course of the RA construct conceptual design. In addition, MISO:

- Provided preliminary and revised historical RA Hours including MaxGen hours, and hourly operating margins for the past four Planning Years at multiple RASC stakeholder meetings; and

- Posted and walked through a step-by-step resource accreditation calculation example worksheet at a RAN workshop and provided a revised example calculation worksheet to reflect the refined proposal; and

- Provided preliminary and revised Resource accreditation SAC values for all resources within each Market Participant portfolio, Market Participant level surplus/shortfall, and at least one CP node with detailed raw information for SAC calculation to illustrate how SAC is calculated; and

- Engaged in one-on-one meetings with Market Participants, upon request, to walk through detailed SAC calculations of their fleet and address any discrepancies or questions.

MISO appreciates that replicating MISO's calculation is important to stakeholders to gain a better understanding of the potential impacts of the proposed changes. To this end, MISO will continue engaging with stakeholders prior to implementation of the proposed changes to provide additional transparency on new accreditation values. For example, MISO has already provided a workshop for stakeholders to solicit their ideas for Module E Capacity Tracking Tool improvements. MISO will have additional workshops in 2022 to further help prepare stakeholders.

- *Transition periods and deferral of reforms* – Stakeholders have requested that MISO phase in various aspects of its proposal to allow more time to adjust to the changes. In addition, stakeholders have requested that MISO delay implementation of the proposal overall for at least another year, and in some cases, significantly longer.

As MISO responds to the Reliability Imperative, the need to transition to a new Resource Adequacy construct requires adoption sooner rather than later. This need has been detailed extensively in the Testimonies of Messrs. Wright, McFarlane, and Smith.

With respect to a transition period, MISO has proposed a number of changes in response to stakeholder requests. First, MISO has adopted the Schedule 53 tiered weighting transition described above. In addition, MISO has proposed a transition period with respect to the implementation of the planned outage provisions established in Schedule 53. Specifically, this transition recognizes planned outages coordinated through the existing processes, with the new proposal being phased over three years.

- *Number of changes* – A number of stakeholders have expressed concern about the number of changes MISO has made to its proposal since extending stakeholders discussions over the last few months.

MISO acknowledges that it has made refinements to its proposal during this period of time. These changes have largely been in response to stakeholder feedback, IMM collaboration, and other improvements identified by MISO to ensure the completeness of the proposal.

VIII. DOCUMENTS SUBMITTED WITH THIS FILING

In addition to this Transmittal Letter, this submission includes:

- Tab A – Redline Tariff[128]
- Tab B – Clean Tariff
- Tab C – Testimony of Shawn McFarlane
- Tab D – Testimony of Jameson Smith
- Tab E – Testimony of Scott Wright

IX. PROPOSED EFFECTIVE DATE

MISO requests an effective date of September 1, 2022 for the Tariff revisions submitted herein. MISO recognizes that this date is beyond 120-days from the date of this filing and therefore requests waiver of Section 35.3(a) of the Commission's regulations to permit this effective date.

As discussed above, MISO also requests that FERC issue an order accepting the proposed Tariff revisions within 120 days from the date of this filing. MISO's request for Commission action on this filing within 120 days from the date of filing is intended to provide regulatory certainty to both stakeholders and MISO with respect to the Tariff provisions applicable to the 2023 / 2024 Planning Year well in advance of the Planning Resource Auction that will be held in the Spring of 2023. Prior to the 2023 / 2024 Planning Year auction, MISO will be working to both enhance the software used in administering the Resource Adequacy Requirements and PRA as well as training stakeholders on how they will demonstrate and monitor their compliance through the tool enhancements.

MISO commits to making a subsequent Section 205 filing with the Commission to update the Tariff sheets to reflect the most up-to-date versions of the then-current Tariff provisions. The update filing will be submitted at least 60 days prior to the proposed effective date of the Tariff provisions as discussed above.

In addition, MISO requests waiver of any requirements of 18 C.F.R. Part 35 the Commission deems applicable to this filing to the extent that the specific requirement is not addressed herein.

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[128] MISO has revised metadata of several sections to change the Tariff Record Titles. MISO's eTariff software does not redline changes to the metadata associated with its Tariff Records, thus no redlines will be shown in the Tariff Record Title.

X. COMMUNICATIONS

MISO respectfully requests waiver of Rule 203(b)(3) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.203(b)(3) (2019), to the extent necessary to permit the designation of more than two persons for service on behalf of MISO in this proceeding and requests all communications related to this filing be directed to:

Michael Kessler
Managing Assistant General Counsel
Midcontinent Independent
System Operator, Inc.
720 City Center Drive
Carmel, Indiana 46032
Telephone: (317) 249-5400
mkessler@misoenergy.org

James C. Holsclaw
Matthew B. Barbara
Nicholas A. Bonaminio
Calfee, Halter & Griswold LLP
115 West Washington Street
Suite 1585
Indianapolis, Indiana 46204
Telephone: (317) 308-7970
jholsclaw@calfee.com

XI. NOTICE AND SERVICE

MISO has served a copy of this filing electronically, including attachments, upon all Tariff Customers, MISO Members, Member representatives of Transmission Owners and Non-Transmission Owners, as well as all state commissions within the region. The filing has been posted electronically on MISO's website currently at https://www.misoenergy.org/legal/ferc-filings/ for other parties interested in this matter.

XII. CONCLUSION

For all of the foregoing reasons, MISO respectfully requests that the Commission accept these proposed revisions for filing, grant the proposed effective date, and grant waiver of any Commission regulation the Commission deems applicable to this filing in order for the Commission to accept it as proposed.

Respectfully submitted,

/s/ Michael Kessler

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Attorneys for the Midcontinent Independent System Operator, Inc.

Attachments

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

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

Exhibit 78
NiSource 2024 Annual Report



MAKING STRIDES. CARRYING MOMENTUM.

NISOURCE 2024 ANNUAL REPORT

NiSource®



WHAT'S INSIDE

MESSAGE FROM OUR PRESIDENT & CHIEF EXECUTIVE OFFICER	1
MESSAGE FROM OUR CHAIR	4
BOARD OF DIRECTORS AND SENIOR MANAGEMENT TEAM	7
STOCKHOLDER INFORMATION	INSIDE BACK COVER
COMPANY INFORMATION	BACK COVER

A MESSAGE FROM OUR PRESIDENT & CHIEF EXECUTIVE OFFICER

LLOYD YATES



TO OUR SHAREHOLDERS,

2024 was an exceptional year for NiSource. We continued making strides toward our vision of being a premier, innovative and trusted energy partner. With a clear and focused strategy, the NiSource team prioritized operational excellence and safety, delivered strong financial results, provided outstanding customer service and executed on sustainability goals – contributing to the short and long-term success of our company.

Notable 2024 highlights reflect the impact of the NiSource team and our commitment to delivering safe and reliable energy at an affordable value:

OPERATIONAL EXCELLENCE AND SAFETY

- For three consecutive years, we delivered better and safer performance by continuing on our path to top decile for Days Away, Restricted or Transferred (DART) and Preventable Vehicle Collisions (PVCs).
- Continued to maintain our certification to the American Petroleum Institute Recommended Practice 1173, which serves as the guiding practice for our Safety Management System (SMS), in addition to being recognized with the ISO 55001 certification from LRQA, one of the world's leading providers of professional engineering and technology services. This accomplishment makes us only one of a few utilities in the world to hold both certifications.
- Progressed our customer service strategy using advanced technology with an upgraded work and asset management system. This system leverages AI-driven data and analytics to boost productivity and efficiency in our dispatch operations.



FINANCIAL

- Reported full year adjusted earnings per share (“EPS”) of $1.75, which exceeded our 2024 guidance range.
- Delivered one-year total shareholder return (TSR) of 43% (94th percentile of our relative TSR group), and three-year TSR of 47.9% (91st percentile of our relative TSR group).
- Achieved a 14.6% FFO/Debt ratio, and 9.4% growth in adjusted EPS over 2023, showcasing our strong cash flow generation and financial discipline.
- Continued to differentiate ourselves from our peers by building a constructive regulatory foundation, and our balance sheet flexibility allows us to both optimize cost of capital for customers and ultimate return on capital for our shareholders.

CUSTOMER SATISFACTION

- Exceeded top level customer satisfaction survey goal, which includes measures of our customers’ satisfaction of interactions with customer service representatives, field service employees, interactive voice response, online survey interaction with the MyAccount website or mobile app and project work/site restoration.
- NIPSCO, Columbia Gas of Ohio, Columbia Gas of Kentucky and Columbia Gas of Virginia were named among the most trusted utility brands by Escalent, following its 2024 Cogent Syndicated Utility Trusted Brand & Customer Engagement: Residential study.
- NIPSCO and Columbia Gas' websites were ranked by E Source among the top utility websites in the U.S. and Canada, with NIPSCO ranked first overall out of ninety-three utilities surveyed.
- Received Chartwell, Inc.'s Silver Award for Excellence in Billing and Payment Programs, recognizing NiSource's data-driven customer engagement strategy that leverages proactive outreach via customers' preferred communications channel.

PEOPLE & CULTURE

- Ranked on Forbes List of America's Best Employers for Women 2024. This is the third year NiSource has ranked in the top ten among utilities.
- Selected as a 2024 Campus Forward Award Winner for the company's commitment to seeking out and hiring early career talent and investments in nurturing and retaining the next generation of diverse talent.

SUSTAINABILITY

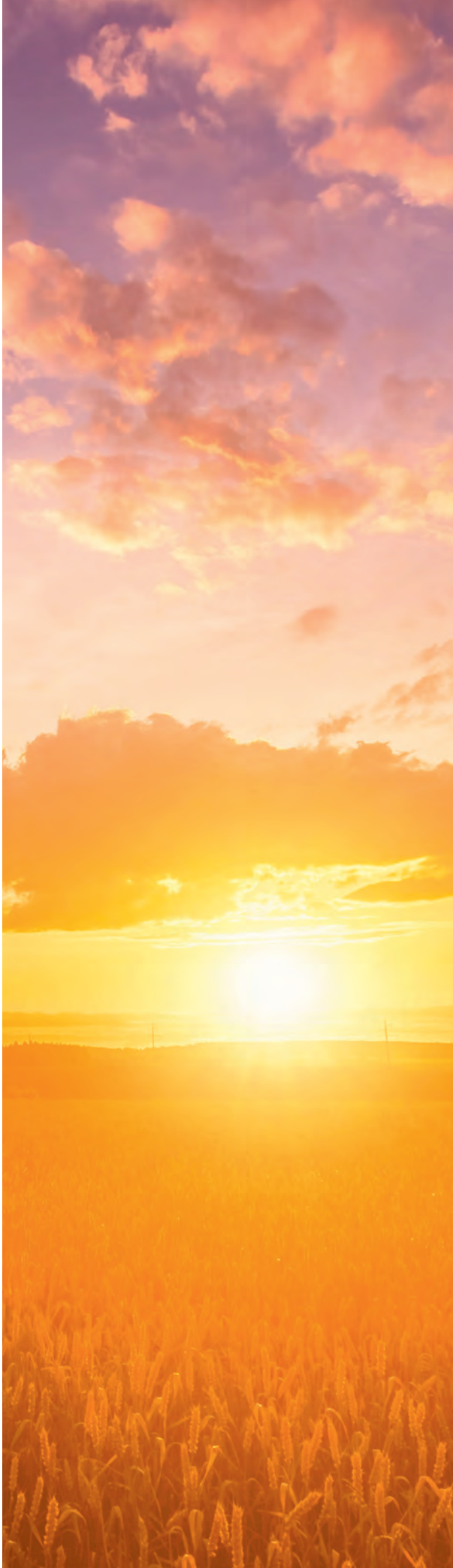
- Continued progress towards our goal of achieving net zero greenhouse gas emissions (GHG) from our operations by 2040 – also referred to as Scope 1 and Scope 2 emissions.
- Remain on track to retire our coal assets and have made substantial progress related to our generation investments that will benefit all stakeholders, as confirmed by our 2024 Integrated Resource Plan (IRP).
- Named to the 2024 Dow Jones Sustainability Indices (DJSI), marking the 11th consecutive year the company has earned the recognition.

These tremendous accomplishments were made possible by the tireless commitment of our approximately 7,700 employees to our customers and communities every day. I am incredibly proud of the NiSource team. Thank you for your continued confidence and for being part of this journey with us. I look forward to another year of strong execution, growth and value in 2025.

Sincerely,



THIS LETTER INCLUDES NON-GAAP MEASURES. RECONCILIATIONS TO THE MOST DIRECTLY COMPARABLE GAAP MEASURES ARE FOUND IMMEDIATELY FOLLOWING THIS LETTER IN SCHEDULE 1.





A MESSAGE FROM OUR CHAIRMAN

KEVIN KABAT

A YEAR MARKED BY NUMEROUS ACHIEVEMENTS

NiSource experienced one of the most successful years in the company's history in 2024. We served our customers exceptionally well by delivering safe and reliable energy at an affordable value. We continued to provide excellent value to our stakeholders through our regulated utility operations across six supportive jurisdictions, ensuring diversification across both fuel types and regulatory environments. Our year was marked by numerous achievements, highlighting our commitment to safety, operational excellence, customer satisfaction, sustainability, financial stewardship and innovation.

A COMMITMENT TO SAFETY AND OPERATIONAL EXCELLENCE

Our commitment to safely serving nearly four million natural gas and electric customers across our six-state footprint under our Columbia Gas and NIPSCO brands is unwavering. Safety is at the heart of everything we do. In 2024, our dedication to ensuring the wellbeing of our employees, contractors, customers and communities was evident in our top decile safety results. This achievement is a testament to our relentless pursuit of excellence and accountability.

One of the standout milestones of the year was equipping our drivers with safety technology through our field mobility and telematics program. By upgrading to state-of-the-art technologies, we've significantly enhanced the way we manage our fleet, ensuring our front-line team members are supported

with the tools they need to put safety above all else.

Our journey towards operational excellence involves continuously improving our processes.

In 2024, we made considerable progress on our Advanced Metering Infrastructure (AMI) system project to upgrade the way the company reads electric and natural gas meters throughout our NIPSCO service area. This project represents our commitment to leveraging advanced technology to enhance our services and provide greater efficiency to our customers.

We have also continued advancing our strategy of using technology to serve our customers more efficiently by implementing an upgraded work and asset management system. This system uses data and analytics through artificial intelligence to raise productivity and efficiency across the dispatch of our operations team, enabling us to better meet our customers' needs.

A TRUSTED CUSTOMER EXPERIENCE

At NiSource, our passion for serving our customers drives us every day. We work every day to listen and anticipate their needs, earn their trust and deliver safe and reliable energy at a cost they value. In 2024, our dedication to customer satisfaction was recognized in the J.D. Power Gas Residential Customer Satisfaction Survey, where all NiSource operating companies outperformed the industry average and scored above their respective segment averages in terms of overall satisfaction. Columbia Gas of Virginia earned the top spot in the South Midsize segment and in the nation. This accolade reflects our team's unwavering commitment to excellence and customer care. We are also incredibly proud of NIPSCO, which received the highest ranking in electric utility business customer satisfaction among mid-sized utilities in the Midwest in J.D. Power's 2024 Electric Utility Business Customer Satisfaction Study. This recognition underscores our ongoing efforts to provide exceptional service and meet the needs of our valued customers.

A SUSTAINABLE FUTURE

We are committed to the outstanding execution of the essential work we do today for our customers, employees, the communities we serve, and our shareholders. We envision a future where we will be a premier, innovative and trusted energy partner, adapting to the evolving needs and preferences of our industry and customers.

With a clear goal in sight, we remain on track to retire coal assets and replace them primarily with renewables. We also received approval of the NIPSCO natural gas peaking resources, which will support system reliability, acting as a bridge for the generation gaps of more intermittent energy sources like wind and solar. And it has the added flexibility to convert from operating on natural gas to operating on zero carbon fuels in the future, such as hydrogen.

Our commitment to a sustainable future remains strong, as all our renewable wind and solar projects remain on target. In 2024, we announced the completion of Cavalry Solar, the third solar project in NIPSCO's generating mix, a crucial step in advancing our energy generation transition plan to provide sustainable, cost-effective and reliable energy now and into the future. We also received regulatory approval for full ownership of both our Gibson and Fairbanks Solar, converting four NIPSCO projects to full ownership, which will materially lower costs to customers.

A FAIR FINANCIAL RETURN

In 2024, we made significant strides in advancing our key priorities of building a constructive regulatory foundation, highly executable financial commitments, upside and incremental investment opportunities, among numerous other achievements.

Additionally, we delivered full-year earnings that exceeded our 2024 guidance range and



extended our financial plan through 2029, with non-GAAP adjusted earnings per share growth expected to be 6-8% annually. The plan is driven by $19.4 billion in expenditures and 8-10% annual rate base growth through 2029, showcasing our commitment to long-term growth and stability.

Our CEO, Lloyd Yates, and his exceptional leadership team continues to serve together to directly support our mission of delivering safe, reliable energy to our customers and driving shareholder value. These leaders, along with their teams, enhance employee experiences, uphold an ethical workplace, meet our legal obligations and help ensure we advance our strategic and operational objectives.

Furthermore, our experienced board of directors has provided invaluable strategic insights and governance. Their unwavering commitment to upholding the highest standards of corporate governance and their collective wisdom have been instrumental in guiding NiSource towards its key priorities and continued success.

On behalf of the Board of Directors, I would like to express our gratitude for your continued interest and support. Thanks to our dedicated team, NiSource delivered remarkable results in 2024, and we are well positioned to carry this momentum into 2025 and beyond.

BOARD OF DIRECTORS

Kevin T. Kabat
Chair of the Board, NiSource Inc., and Retired Vice Chair and CEO, Fifth Third Bancorp

Peter A. Altabef
Chair and CEO, Unisys Corporation*

Sondra L. Barbour
Retired Executive Vice President, Information Systems & Global Solutions, Lockheed Martin Corporation

Theodore H. Bunting, Jr.
Retired Group President, Utility Operations, Entergy Corporation

Eric L. Butler
President and CEO, Aswani-Butler Investment Associates, and Retired Executive Vice President, Union Pacific Corporation

Deborah A. Henretta
Partner, Council Advisors and Retired Group President, Procter & Gamble Co.

Deborah A. P. Hersman
Retired Chair, National Transportation Safety Board

Michael E. Jesanis
Co-founder and Former Managing Director, HotZero, LLC, and Retired President and CEO, National Grid USA

William D. Johnson
Retired President and CEO, Pacific Gas and Electric

Cassandra S. Lee
Senior Vice President and Chief Financial Officer, AT&T Inc. Mobility and Consumer Wireline Segments

John McAvoy
Retired Chair, President and CEO, Consolidated Edison Inc., and Retired Chair and CEO, Consolidated Edison of New York, Inc.

Lloyd M. Yates
President and CEO, NiSource Inc.

BOARD OF DIRECTORS DEMOGRAPHICS

12 Total
67% Men, 33% Women
33% Race/Ethnicity

SENIOR MANAGEMENT TEAM

Lloyd M. Yates
President and Chief Executive Officer

Shawn Anderson
Executive Vice President and Chief Financial Officer

Melanie Berman
Executive Vice President, Administration and Chief Human Resources Officer

Melody Birmingham
Executive Vice President and Group President, Utilities

Kimberly S. Cuccia
Executive Vice President, General Counsel and Corporate Secretary

William (Bill) Jefferson
Executive Vice President, Chief Operating and Safety Officer

Michael Luhrs
Executive Vice President, Technology, Customer and Chief Commercial Officer

SENIOR MANAGEMENT TEAM DEMOGRAPHICS

7 Total
57% Men, 43% Women
43% Race/Ethnicity

ALL INFORMATION ON THIS PAGE IS AS OF MARCH 31, 2025
* EFFECTIVE APRIL 1, 2025, MR. ALTABEF WILL CEASE BEING THE CEO, BUT WILL REMAIN THE CHAIR.

SCHEDULE 1

Reconciliation of Consolidated Net Income Available to Common Shareholders to Adjusted Net Income Available to Common Shareholders (Non-GAAP) (Unaudited)

	Twelve Months Ended December 31,	
(in millions, except per share amounts)	**2024**	2023
GAAP Net Income Available to Common Shareholders	**$ 739.7**	$ 661.7
Adjustments to Operating Income:		
Operating Revenues:		
Weather - compared to normal[1]	**60.4**	60.6
Total adjustments to operating income	**60.4**	60.6
Other Income (Deductions):		
Income Taxes:		
Tax effect of above items[2]	**(15.5)**	(15.8)
Preferred Dividends:		
Preferred dividends redemption premium[3]	**14.0**	9.8
Total adjustments to net income	**58.9**	54.6
Adjusted Net Income Available to Common Shareholders	**$ 798.6**	$ 716.3
Diluted Average Common Shares	**456.0**	447.9
GAAP Diluted Earnings Per Share[4]	**$ 1.62**	$ 1.48
% Growth in Diluted Earnings Per Share from Prior Year[5]	**9.5%**	
Adjustments to diluted earnings per share	**0.13**	0.12
Adjusted Earnings Per Share	**$ 1.75**	$ 1.60
% Growth in Adjusted Earnings Per Share from Prior Year[6]	**9.4%**	

[1] Represents the variance between actual and normal weather. Beginning in 2024, the adjustment for NIPSCO Operations excludes the impact of non-controlling interest.
[2] Represents income tax expense calculated using the statutory tax rates for legal entity.
[3] Represents the difference between the carrying value on the redemption date of the Series B Preferred Stock and the total amount of consideration paid to redeem, net of the fair value of common shares issued during 2024.
[4] GAAP Diluted Earnings Per Share includes the effects of income allocated to participating securities and adds back the dilutive effect of Equity Units in the prior year. Please refer to Note 5, "Earnings Per Share," within the Company's Annual Report on Form 10-K for the period ended December 31, 2024.
[5] % growth taken from change in diluted earnings per share over prior year divided by prior year diluted earnings per share.
[6] % growth taken from change in adjusted earnings per share over prior year divided by prior year adjusted earnings per share.

Reconciliation of Net Cash Flows from Operating Activities to FFO to Debt (Adjusted) (Non-GAAP) (Unaudited)

ANNUAL FFO/DEBT RECONCILIATION ($ IN MILLIONS)

($ in millions)

	2024
Net Cash Flows from Operating Activities	1,782
- Accounts receivable	(102)
- Gas storage and other inventories	102
- Accounts payable	72
- Exchange gas receivable/payable	(134)
- Other accruals	10
- Prepayments and other current assets	(76)
- Other adjustments	(34)
Funds from Operations (Adjusted)	**1,944**
Long-term debt	12,075
+ Current portion of long-term debt	1,281
+ Short-term borrowings	605
+ Other adjustments	(657)
Total Adjusted Debt	**13,304**
FFO to Debt (Adjusted)	**14.6%**

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

FORM 10-K

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d)**

OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2024

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 number 001-16189

NiSource Inc.

(Exact name of registrant as specified in its charter)

DE	35-2108964
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
801 East 86th Avenue Merrillville, IN	46410
(Address of principal executive offices)	(Zip Code)

(877) 647-5990
(Registrant's telephone number, including area code)

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

Title of Each Class	Trading Symbol(s)	Name of Each Exchange on Which Registered
Common Stock, par value $0.01 per share	NI	NYSE

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☑ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Act. Yes ☐ No ☑

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.
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).
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 definition of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12-b-2 of the Exchange Act.

Large accelerated filer ☑ Accelerated Filer ☐ Emerging Growth Company ☐ Non-accelerated Filer ☐ Smaller Reporting 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. ☐

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☑

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrants included in the filing reflect the correction of an error to previously issued financial statements. ☐

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240. 10D-1(b).☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☑

The aggregate market value of the registrant's common stock, par value $0.01 per share (the "Common Stock") held by non-affiliates was approximately $13,022,151,904 based upon the June 30, 2024, closing price of $28.81 on the New York Stock Exchange.
There were 469,939,639 shares of Common Stock outstanding as of February 5, 2025.

Documents Incorporated by Reference

Part III of this report incorporates by reference specific portions of the Registrant's Notice of Annual Meeting and Proxy Statement relating to the Annual Meeting of Stockholders to be held on May 12, 2025.

CONTENTS

			Page No.
	Defined Terms		3
Part I			
	Item 1.	Business	7
	Item 1A.	Risk Factors	17
	Item 1B.	Unresolved Staff Comments	31
	Item 1C.	Cybersecurity	31
	Item 2.	Properties	32
	Item 3.	Legal Proceedings	32
	Item 4	Mine Safety Disclosures	32
Part II			
	Item 5.	Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities	33
	Item 6.	Reserved	34
	Item 7.	Management's Discussion and Analysis of Financial Condition and Results of Operations	35
	Item 7A.	Quantitative and Qualitative Disclosures About Market Risk	56
	Item 8.	Financial Statements and Supplementary Data	57
	Item 9.	Changes in and Disagreements With Accountants on Accounting and Financial Disclosure	122
	Item 9A.	Controls and Procedures	122
	Item 9B.	Other Information	124
	Item 9C.	Disclosure Regarding Foreign Jurisdictions that Prevent Inspections	124
Part III			
	Item 10.	Directors, Executive Officers and Corporate Governance	125
	Item 11.	Executive Compensation	125
	Item 12.	Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters	125
	Item 13.	Certain Relationships and Related Transactions, and Director Independence	125
	Item 14.	Principal Accounting Fees and Services	125
Part IV			
	Item 15.	Exhibits, Financial Statement Schedules	126
	Item 16.	Form 10-K Summary	132
	Signatures		133

DEFINED TERMS

The following is a list of frequently used abbreviations or acronyms that are found in this report:

NiSource Subsidiaries and Affiliates (not exhaustive)

Columbia of Kentucky	Columbia Gas of Kentucky, Inc.
Columbia of Maryland	Columbia Gas of Maryland, Inc.
Columbia of Ohio	Columbia Gas of Ohio, Inc.
Columbia of Pennsylvania	Columbia Gas of Pennsylvania, Inc.
Columbia of Virginia	Columbia Gas of Virginia, Inc.
NIPSCO	Northern Indiana Public Service Company LLC
NIPSCO Holdings I	NIPSCO Holdings I LLC
NIPSCO Holdings II	NIPSCO Holdings II LLC
NIPSCO Generation	NIPSCO Generation LLC
NiSource ("we," "us" or "our")	NiSource Inc.
Rosewater	Rosewater Wind Generation LLC and its wholly owned subsidiary, Rosewater Wind Farm LLC
Indiana Crossroads Solar	Indiana Crossroads Solar Generation LLC and its wholly owned subsidiary, Meadow Lake Solar Park LLC
Indiana Crossroads Wind	Indiana Crossroads Wind Generation LLC and its wholly owned subsidiary, Indiana Crossroads Wind Farm LLC
Dunns Bridge I	Dunns Bridge I Solar Generation LLC and its wholly owned subsidiary, Dunns Bridge Solar Center LLC
Dunns Bridge II	Dunns Bridge II Solar Generation LLC
Gibson	Gibson Solar Generation LLC
Fairbanks	Fairbanks Solar Generation LLC
Cavalry	Cavalry Solar Generation LLC

Abbreviations and Other

AFUDC	Allowance for funds used during construction
AOCI	Accumulated Other Comprehensive Income (Loss)
ASC	Accounting Standards Codification
ASU	Accounting Standards Update
ATM	At-the-market
BIP	BIP Blue Buyer L.L.C
BIP Blue Buyer VCOC L.L.C	BIP Blue Buyer VCOC L.L.C., a Delaware limited liability company and also an affiliate of Blackstone
Blackstone	Blackstone Infrastructure Partners L.P.
BTA	Build-transfer agreement
CCGT	Combined Cycle Gas Turbine
CCRs	Coal Combustion Residuals
CEO	Chief Executive Officer
CEP	Capital Expenditure Program
CERCLA	Comprehensive Environmental Response Compensation and Liability Act (also known as Superfund)
CFO	Chief Financial Officer
CISA	Certified Information Systems Auditor
CISO	Chief Information Security Officer
CISSP	Certified Information Systems Security Professional
CODM	Chief Operating Decision Maker

DEFINED TERMS

Columbia Operations	Reportable segment comprised of the results of NiSource Gas Distribution company, including all of its Columbia Gas distribution companies and related subsidiaries
Corporate Units	Series A Corporate Units
CPCN	Certificate of Public Convenience and Necessity
CRISC	Certified in Risk and Information Systems Control
DSIC	Distribution System Improvement Charge
DSM	Demand Side Management
EPA	United States Environmental Protection Agency
EPS	Earnings per share
Equity Units	Series A Equity Units
FAC	Fuel adjustment clause
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FMCA	Federally Mandated Cost Adjustment
GAAP	Generally Accepted Accounting Principles
GCA	Gas cost adjustment
GCT	Generation Cost Tracker
GHG	Greenhouse gases
GWh	Gigawatt hours
HLBV	Hypothetical Liquidation at Book Value
IIJA	Infrastructure Investment and Jobs Act
IRA	Inflation Reduction Act
IRP	Infrastructure Replacement Program
IRS	Internal Revenue Service
IURC	Indiana Utility Regulatory Commission
JV	Joint Venture
LDCs	Local distribution companies
LIFO	Last-in, first-out
LIHEAP	Low Income Heating Energy Assistance Programs
Massachusetts Business	All of the assets sold to, and liabilities assumed by, Eversource pursuant to the Asset Purchase Agreement
MGP	Manufactured Gas Plant
MISO	Midcontinent Independent System Operator
MMDth	Million dekatherms
MW	Megawatts
MWh	Megawatt hours
NERC CIP	North American Electric Reliability Corporation Critical Infrastructure Protection
NIPSCO Electric	The electric generation and transmission activities of the NIPSCO Operations reportable segment
NIPSCO Gas	The gas distribution activities of the NIPSCO Operations reportable segment
NIPSCO Minority Interest Transaction	A transaction between NiSource, NIPSCO Holdings II (sole owner of NIPSCO) and an affiliate of Blackstone pursuant to a purchase and sale agreement entered into on June 17, 2023, that offered equity interests in NIPSCO Holdings II in exchange for capital contributions by the parties.

DEFINED TERMS

NIPSCO Operations	Reportable segment comprised of the results of NIPSCO Holdings I, NIPSCO Holdings II, and NIPSCO and all related subsidiaries
NYMEX	The New York Mercantile Exchange
OPEB	Other Postretirement and Postemployment Benefits
OT	Operational Technology
PCB	Polychlorinated biphenyls
PHMSA	Pipeline and Hazardous Materials Safety Administration
PPA	Power Purchase Agreement
PSC	Public Service Commission
PUCO	Public Utilities Commission of Ohio
ROE	Return on Equity
RNG	Renewable Natural Gas
ROU	Right of Use
SAVE	Steps to Advance Virginia's Energy Plan
Scope 1 GHG Emissions	Direct emissions from sources owned or controlled by us (e.g., emissions from our combustion of fuel, vehicles, and process emissions and fugitive emissions)
Scope 2 GHG Emissions	Indirect emissions from sources owned or controlled by us
SEC	Securities and Exchange Commission
SMRP	Safety Modification and Replacement Program
SMS	Safety Management System
STRIDE	Strategic Infrastructure Development and Enhancement
TCJA	An Act to provide for reconciliation pursuant to titles II and V of the concurrent resolution on the budget for fiscal year 2018 (commonly known as the Tax Cuts and Jobs Act of 2017)
TDSIC	Transmission, Distribution and Storage System Improvement Charge
TSA	Transportation Security Administration
VIE	Variable Interest Entity
WAM	Work and Asset Management enterprise resourcing system

Note regarding forward-looking statements

This Annual Report on Form 10-K contains "forward-looking statements," within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). Investors and prospective investors should understand that many factors govern whether any forward-looking statement contained herein will be or can be realized. Any one of those factors could cause actual results to differ materially from those projected. These forward-looking statements include, but are not limited to, statements concerning our plans, strategies, objectives, expected performance, expenditures, recovery of expenditures through rates, stated on either a consolidated or segment basis, and any and all underlying assumptions and other statements that are other than statements of historical fact. Expressions of future goals and expectations and similar expressions, including "may," "will," "should," "could," "would," "aims," "seeks," "expects," "plans," "anticipates," "intends," "believes," "estimates," "predicts," "potential," "targets," "forecast," and "continue," reflecting something other than historical fact are intended to identify forward-looking statements. All forward-looking statements are based on assumptions that management believes to be reasonable; however, there can be no assurance that actual results will not differ materially.

Factors that could cause actual results to differ materially from the projections, forecasts, estimates and expectations discussed in this Annual Report on Form 10-K include, among other things:

- our ability to execute our business plan or growth strategy, including utility infrastructure investments, or business opportunities, such as data center development and related generation sources and transmission capabilities to meet potential load growth;
- our ability to manage data center growth in our service territories;

- potential incidents and other operating risks associated with our business;
- our ability to work successfully with our third-party investors;
- our ability to adapt to, and manage costs related to, advances in technology, including alternative energy sources and changes in laws and regulations;
- our increased dependency on technology;
- impacts related to our aging infrastructure;
- our ability to obtain sufficient insurance coverage and whether such coverage will protect us against significant losses;
- the success of our electric generation strategy;
- construction risks and supply risks;
- fluctuations in demand from residential and commercial customers;
- fluctuations in the price of energy commodities and related transportation costs or an inability to obtain an adequate, reliable and cost-effective fuel supply to meet customer demand;
- our ability to attract, retain or re-skill a qualified, diverse workforce and maintain good labor relations;
- our ability to manage new initiatives and organizational changes;
- the performance and quality of third-party suppliers and service providers;
- our ability to manage the financial and operational risks related to achieving our carbon emission reduction goals, including our Net Zero Goal (as defined below), including any future associated impact from business opportunities such as data center development as those opportunities evolve;
- potential cybersecurity attacks or security breaches;
- increased requirements and costs related to cybersecurity;
- the actions of activist stockholders;
- any damage to our reputation;
- the impacts of natural disasters, potential terrorist attacks or other catastrophic events;
- the physical impacts of climate change and the transition to a lower carbon future;
- our debt obligations;
- any changes to our credit rating or the credit rating of certain of our subsidiaries;
- adverse economic and capital market conditions, including increases in inflation or interest rates, recession, or changes in investor sentiment;
- economic regulation and the impact of regulatory rate reviews;
- our ability to obtain expected financial or regulatory outcomes;
- economic conditions in certain industries;
- the reliability of customers and suppliers to fulfill their payment and contractual obligations;
- the ability of our subsidiaries to generate cash;
- pension funding obligations;
- potential impairments of goodwill;
- the outcome of legal and regulatory proceedings, investigations, incidents, claims and litigation;
- compliance with changes in, or new interpretations of applicable laws, regulations and tariffs;
- the cost of compliance with environmental laws and regulations and the costs of associated liabilities;
- changes in tax laws or the interpretation thereof;
- and other matters set forth in Item 1, "Business," Item 1A, "Risk Factors" and Part II, Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations," of this report, some of which risks are beyond our control.

In addition, the relative contributions to profitability by each business segment, and the assumptions underlying the forward-looking statements relating thereto, may change over time.

All forward-looking statements are expressly qualified in their entirety by the foregoing cautionary statements. We undertake no obligation to, and expressly disclaim any such obligation to, update or revise any forward-looking statements to reflect changed assumptions, the occurrence of anticipated or unanticipated events or changes to the future results over time or otherwise, except as required by law.

PART I

ITEM 1. BUSINESS

NISOURCE INC.

Business

NiSource Inc. is an energy holding company under the Public Utility Holding Company Act of 2005 whose primary subsidiaries are fully regulated natural gas and electric utility companies, serving approximately 3.8 million customers in six states. NiSource is the successor to an Indiana corporation organized in 1987 under the name of NIPSCO Industries, Inc., which changed its name to NiSource Inc. on April 14, 1999.

NiSource's principal subsidiaries include NiSource Gas Distribution Group, Inc. (a holding company that owns Columbia of Kentucky, Columbia of Maryland, Columbia of Ohio, Columbia of Pennsylvania, and Columbia of Virginia), and NIPSCO Holdings I (a holding company that owns a controlling interest in NIPSCO, a gas and electric utility). NiSource derives substantially all of its revenues and earnings from the operating results of these rate-regulated businesses.

Business Strategy

Our business strategy focuses on providing safe and reliable service through our core, rate-regulated, asset-based utilities, with the goal of adding value to all of our stakeholders. Our utilities continue to advance our core safety, infrastructure and environmental investment programs, supported by complementary regulatory and customer initiatives across the six states in which we operate. Our goal is to develop strategies that (i) support long-term infrastructure investment and safety programs to better serve our customers, (ii) align our tariff structures with our cost structure, and (iii) drive value and enable growth in an evolving energy ecosystem. These strategies focus on improving safety and reliability, enhancing customer experience, pursuing regulatory and legislative initiatives to increase accessibility for customers currently not on our gas and electric service, ensuring customer affordability and reducing emissions while generating sustainable returns.

We remain committed to the advancement of our SMS for the safety of our customers, communities and employees. Our SMS is the established operating model within NiSource. NiSource continues to maintain its certification to the American Petroleum Institute Recommended Practice 1173, which serves as the guiding practice for our SMS. In 2024, NiSource was recognized with the ISO 55001 certification from LRQA, one of the world's leading providers of professional engineering and technology services. Achieving this international certification for asset management systems recognizes NiSource's commitment to safety for our people, systems and customers. These certifications are important milestones for our SMS and NiSource's ongoing journey towards operational excellence.

NiSource has two reportable segments: Columbia Operations and NIPSCO Operations. The remainder of our operations, which are not significant enough on a stand-alone basis to warrant treatment as an operating segment, consist of our centralized corporate activities and are primarily comprised of interest expense on holding company debt and unallocated corporate costs and activities. The following is a summary of the business for each reporting segment. Refer to Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Note 21, "Business Segment Information," in the Notes to Consolidated Financial Statements for additional information related to each segment.

Columbia Operations

Columbia Operations provides natural gas to approximately 2.4 million residential, commercial and industrial customers in Ohio, Pennsylvania, Virginia, Kentucky, and Maryland. We operate approximately 37,200 miles of distribution main pipeline plus the associated individual customer service lines and 330 miles of transmission main pipeline located in our service areas described above. Throughout our service areas we also have gate stations and other operations support facilities. See below for information on our owned operating facilities. There were no significant disruptions to our system or facilities during 2024.

Facility Name	Location	Type	Storage Capacity (MCF)
Blackhawk Underground Storage[(1)]	Beaver Falls, PA	Natural Gas	1,700,000
Eagle Cove Propane	Petersburgh, VA	Propane Gas	863
South Wales Propane	Jeffersonton, VA	Propane Gas	863
Portsmouth Propane-Air	Portsmouth, VA	Propane-Air Gas	17,300
Total Capacity			1,719,026

[(1)]NiSource has entered into an agreement to sell this facility, subject to approval by the Pennsylvania Public Utility Commission.

NiSource Inc.

Competition. Due to open access and the deregulation of natural gas supplies, our LDC customers can purchase gas directly from producers and marketers in an open, competitive market. Certain of our subsidiaries are involved in programs that provide our residential and commercial customers the opportunity to purchase their natural gas requirements from third parties and use our subsidiaries for transportation services. As of December 31, 2024, 33.9% of our residential customers and 41.2% of our commercial customers participated in such programs.

We compete with (i) investor-owned, municipal, and cooperative electric utilities throughout our service areas, (ii) other regulated and unregulated natural gas intra and interstate pipelines and (iii) other alternate fuels, such as propane and fuel oil. We continue to be a well-positioned competitor in the energy markets in which we operate due to customer preference for natural gas.

Additionally, we are subject to seasonal fluctuations in sales. Revenues from our gas distribution operations are more significant during the heating season, which is from October through May. Please refer to Part II, Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations - Results and Discussion of Operations - Columbia Operations," for additional information.

NIPSCO Operations

NIPSCO Gas

NIPSCO Gas distributes natural gas to approximately 0.9 million customers in northern Indiana. We operate approximately 17,900 miles of distribution main pipeline plus the associated individual customer service lines and 690 miles of transmission main pipeline located in our northern Indiana service areas. Throughout northern Indiana, we also have gate stations and other operations support facilities. See below for information on our owned operating facilities. There were no significant disruptions to our system or facilities during 2024.

Facility Name	Location	Type	Storage Capacity (MCF)
Royal Center Underground Storage	Royal Center, IN	Natural Gas	7,240,000
Rolling Prairie LNG	Rolling Prairie, IN	Liquified Natural Gas	4,000,000
Total Capacities			11,240,000

Competition. Similar to the Columbia Operations segment, NIPSCO Gas also operates in an open and competitive market which allows retail customers to purchase gas directly from producers and marketers. As of December 31, 2024, 6.7% of our residential customers and 17.6% of our commercial customers participated in such programs.

We compete with (i) investor-owned, municipal, and cooperative electric utilities throughout our northern Indiana service area, (ii) other regulated and unregulated natural gas intra and interstate pipelines and (iii) other alternate fuels, such as propane and fuel oil.

Additionally, we are subject to seasonal fluctuations in sales. Revenues from our gas distribution operations are more significant during the heating season, which is from October through May. Please refer to Part II, Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations - Results and Discussion of Operations - NIPSCO Operations," for additional information.

ITEM 1. BUSINESS

NiSource Inc.

NIPSCO Electric

We generate, transmit and distribute electricity to approximately 0.5 million customers in 20 counties in the northern part of Indiana and also engage in wholesale electric and transmission transactions. Our transmission system, has voltages from 69,000 to 765,000 volts, and consists of approximately 3,000 circuit miles. We are interconnected with eight neighboring electric utilities. We operate 66 transmission and 250 distribution substations, and own approximately 311,300 poles. We own and operate generation assets as well as source power through PPAs. We continue to transition our generation portfolio from coal-fired generation to lower-emission sources. We currently have six owned renewable generation facilities in service: Rosewater, Indiana Crossroads Wind, Indiana Crossroads Solar, Dunns Bridge I Solar, Cavalry Solar and Storage and Dunns Bridge II Solar and Storage. Cavalry Solar and Storage went into service May 2024 and Dunns Bridge II Solar and Storage went into service in January 2025. As of December 31, 2024, we have multiple PPAs that provide 600 MW of capacity, with contracts expiring between 2038 and 2040. We also operate two hydro electric generation facilities, a CCGT, and two coal generation facilities. The R.M. Schahfer coal facility is scheduled to be retired by the end of 2025 and the Michigan City coal facility is scheduled to be retired by the end of 2028. Our generating facilities had no material unplanned interruptions during 2024. See below for information on our owned generating facilities:

Facility Name	Location	Fuel Type	Generating Capacity (MW)[1]
R.M. Schahfer	Wheatfield, IN	Steam - Coal	722
Michigan City	Michigan City, IN	Steam - Coal	455
Sugar Creek[2]	West Terre Haute, IN	CCGT	578
R.M. Schahfer	Wheatfield, IN	Natural Gas	155
Oakdale	Carroll County, IN	Hydro	9
Norway	White County, IN	Hydro	7
Rosewater[3]	White County, IN	Wind	102
Indiana Crossroads Wind[3]	White County, IN	Wind	302
Dunns Bridge I[3]	Jasper County, IN	Solar	265
Indiana Crossroads Solar[3]	White County, IN	Solar	200
Cavalry Solar and Storage[4]	White County, IN	Solar and Storage	200
Dunns Bridge II[4]	Jasper County, IN	Solar and Storage	435
Total MW Capacity			3,430

[1]Represents current net generating capability of each fossil fuel and hydro generating facility. Nameplate capacity is listed for wind and solar generating facilities.

[2]Represents capacity as of December 31, 2024. Sugar Creek is expected to further increase capacity pending MISO approval in 2025.

[3]NIPSCO is the managing partner of these JVs. Refer to Note 4, "Noncontrolling Interests," in the Notes to Consolidated Financial Statements for more information.

[4]Cavalry Solar and Storage has installed battery storage capacity of 45MW over a four-hour duration. Dunns Bridge has installed battery storage capacity of 56MW over a four-hour duration.

NIPSCO's 2024 Integrated Resource Plan ("2024 Plan") was submitted to the IURC in December 2024. The 2024 Plan informs future generation investments required to ensure reliability for NIPSCO's customers and incorporated factors such as anticipated load growth from data centers and other economic development opportunities, new EPA emissions rules, and evolving MISO resource accreditation rules. The 2024 Plan maintains the retirement decisions and capacity additions identified in the 2018 and 2021 Integrated Resource Plans and calls for additional generation resources through 2029 to support capacity requirements. In addition, if significant new data center load is contracted, the 2024 Plan calls for additional gas-fired resources to support that additional capacity. Refer to Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations" for further discussion of these plans.

NiSource Inc.

NIPSCO participates in the MISO transmission service and wholesale energy market. MISO is a nonprofit organization created in compliance with FERC regulations to improve the flow of electricity in the regional marketplace and to enhance electric reliability. Additionally, MISO is responsible for managing energy markets, transmission constraints and the day-ahead, real-time, Financial Transmission Rights and ancillary markets. NIPSCO has transferred functional control of its electric transmission assets to MISO, and transmission service for NIPSCO occurs under the MISO Open Access Transmission Tariff. NIPSCO generating units are dispatched by MISO which takes into account economics, reliability of the MISO system and unit availability. During the year ended December 31, 2024, NIPSCO generating units, inclusive of its owned renewable generation facilities, were dispatched to meet 55.4% of its overall system load, and the remainder of the overall system load was procured through PPAs and the MISO market.

Competition. Our NIPSCO Electric utility generally has exclusive service areas under Indiana regulations and retail electric customers in Indiana do not have the ability to choose their electric supplier. NIPSCO faces non-utility competition from other energy sources, such as self-generation by large industrial customers and other distributed energy sources.

Our NIPSCO Operations are subject to seasonal fluctuations in sales. Revenues from electric operations are more significant during the cooling season, which is primarily from June through September. Please refer to Part II, Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations - Results and Discussion of Operations - NIPSCO Operations," for additional information.

Regulatory

The regulatory landscape, at both the state and federal levels, continues to evolve, impacting the operations and financial results of our operating companies. Management continually seeks new ways to be more competitive and efficient in this environment, while keeping service and affordability for customers at the forefront. We believe we are, in all material respects, in compliance with such laws and regulations and do not expect future compliance requirements to have a material impact on our capital expenditures, earnings, or competitive position. While we continue to monitor existing and pending laws and regulations, the impact of regulatory changes cannot be predicted with certainty.

Rate Case Actions. The following table describes current rate case actions as applicable in each of our jurisdictions. See "Cost Recovery and Trackers" below for further detail on trackers.

(in millions)

Company	Approved ROE	Requested Incremental Revenue	Approved Incremental Revenue	Filing Date	Rates Effective
Approved Rates Cases					
Columbia of Pennsylvania[(1)]	None specified	$ 124.1	$ 74.0	March 15, 2024	December 2024
Columbia of Maryland[(1)]	None specified	$ 6.5	$ 3.9	May 12, 2023	December 2023
Columbia of Kentucky	9.75 %	$ 23.8	$ 14.3	May 16, 2024	January 2025
Columbia of Virginia[(2)]	None specified	$ 40.5	$ 25.8	April 29, 2022	October 2022
Columbia of Ohio	9.60 %	$ 221.4	$ 68.3	June 30, 2021	March 2023
NIPSCO - Gas[(3)]	9.75 %	$ 161.9	$ 120.9	October 25, 2023	August 2024
NIPSCO - Electric[(4)]	9.80 %	$ 291.8	$ 261.9	September 19, 2022	August 2023
Pending Rate Cases					
NIPSCO - Electric[(5)]	In process	$ 368.7	In process	September 12, 2024	September 2025
Columbia of Virginia[(6)]	In process	$ 37.2	In process	April 29, 2024	October 2024
Columbia of Maryland	In process	$ 10.7	In process	September 24, 2024	April 2025

[(1)] No approved ROE is identified for this matter since the approved revenue increase is the result of a black box settlement under which parties agree upon the amount of increase.

[(2)]The approved rate case resulted in a black box settlement, representing a settlement to a specific revenue increase but not a specified ROE. The settlement provides use of a 9.70% ROE for future SAVE filings.

[(3)]New rates were implemented in 2 steps, with implementation of Step 1 rates effective in August 2024 and Step 2 rates to be effective no later than March 2025.

[(4)]New rates were implemented in 2 steps, with implementation of Step 1 rates in August 2023 and Step 2 rates effective in March 2024.

[(5)]On February 7, 2025, NIPSCO and certain intervening parties filed a Joint Stipulation and Settlement Agreement with the IURC reflecting an annual revenue increase of $257.0 million. New rates proposed to be implemented in 2 steps, with implementation of Step 1 rates effective no later than September 2025 and Step 2 rates to be effective no later than March 2026.

[(6)]Rates are effective on an as filed basis and subject to refund. Columbia of Virginia and certain intervening parties, filed a Joint Stipulation and Proposed Recommendation for settlement on December 5, 2024, for an annual revenue increase of $28.2 million, net of SAVE.

ITEM 1. BUSINESS

NiSource Inc.

FERC. Our service company and operating companies are subject to varying degrees of regulation by the FERC. NiSource Corporate Services files a FERC Form 60 annual report with its financial information as a FERC jurisdictional centralized service company. NiSource also files an annual FERC Form 61 which contains a narrative description of the service company's functions during the prior calendar year.

As natural gas LDCs, Columbia of Maryland, Columbia of Ohio, Columbia of Pennsylvania, Columbia of Virginia, Columbia of Kentucky and NIPSCO have limited jurisdictional certificates to transport gas in their respective service territories and into interstate commerce.

As an electric company, NIPSCO has Market Based Rate authority and is a Transmission Owner subject to FERC jurisdiction. NIPSCO files the following reports annually:

- FERC Form 1, which is a comprehensive financial and operating report,
- FERC Form 566, which is a list of its 20 largest purchases of electricity over the past three years,
- FERC Form 715, which is its Annual Transmission Planning and Evaluation Report and the base case power flow data from the Eastern Interconnection Reliability Assessment Group Multiregional Modeling Working Group, which was used by NIPSCO for transmission planning and,
- FERC Form 730, which is NIPSCO's Report of Transmission Investment Activity.

As a Transmission Owner subject to the MISO Transmission Owners Agreement and Tariff, NIPSCO has various FERC jurisdictional obligations such as maintaining its Attachment O formula rates and corresponding protocols. NIPSCO also has FERC approvals to make affiliate transactions between itself and various JVs. NIPSCO's officers, on the electric side, are also subject to FERC's interlocking directorate rules and reporting requirements.

Regulatory Framework. The gas distribution activities of our Columbia and NIPSCO Operations have pursued non-traditional revenue sources within the evolving natural gas marketplace. These efforts include (i) gas supply cost incentive mechanisms for service to their core markets, and (ii) the sale of on-system services in the companies' service territories. The on-system services are offered by us to customers and include products such as the transportation and balancing of gas on the gas distribution operations utility's system. The incentive mechanisms give the gas distribution operations utilities an opportunity to share in the savings created from such situations as gas purchases made below an agreed upon benchmark price and the remarketing of unused pipeline capacity to reduce overall pipeline costs.

We recognize that energy efficiency reduces emissions, conserves natural resources and saves our customers money. Our gas distribution companies offer programs such as energy efficiency upgrades, home checkups and weatherization services. The increased efficiency of natural gas appliances and improvements in home building codes and standards contribute to a long-term trend of declining average use per customer. While we are looking to expand offerings so the energy efficiency programs can benefit as many customers as possible, our gas distribution operations utilities have pursued changes in rate design to more effectively match recoveries with costs incurred. Columbia of Ohio has adopted a straight fixed variable rate design for residential and small commercial customers that closely links the recovery of fixed costs with fixed charges. Columbia of Maryland and Columbia of Virginia have regulatory approval for weather and revenue normalization adjustments for certain customer classes, which adjust monthly revenues that exceed or fall short of approved levels. Columbia of Pennsylvania continues to operate its pilot residential weather normalization adjustment and also has a fixed customer charge. This weather normalization adjustment only adjusts revenues when actual weather compared to normal varies by more than 3%. Columbia of Kentucky incorporates a weather normalization adjustment for certain customer classes and also has a fixed customer charge. NIPSCO Gas and Electric include a fixed customer charge for residential and small commercial and industrial customer classes. NIPSCO Gas has also received approval and implemented a weather normalization adjustment for certain of its customer classes.

While increased efficiency of electric appliances and improvements in home building codes and standards have similarly impacted the average use per electric customer in recent years, NIPSCO expects future growth in per customer usage as a result of increasing electric applications, such as electric vehicles. These ongoing changes in use of electricity will likely lead to development of innovative rate designs, and NIPSCO will continue efforts to design rates that increase the certainty of recovery of fixed costs.

ITEM 1. BUSINESS

NiSource Inc.

Cost Recovery and Trackers. Comparability of our operating results is impacted by regulatory trackers that allow for the recovery in rates of certain costs. Certain approved regulatory tracker mechanisms allow for abbreviated regulatory proceedings in order for the operating companies to quickly implement revised rates and recover associated costs.

A portion of the NIPSCO Operations' and Columbia Operations' gas distribution revenue is related to the recovery of gas costs through GCA's, the review of which occurs through standard regulatory proceedings. All states in our operating area require periodic review of actual gas procurement activity to determine prudence and confirm the recovery of prudently incurred energy commodity costs supplied to customers.

A portion of the NIPSCO Operations' revenue is related to the recovery of fuel costs to generate power and the fuel costs related to purchased power. These costs are recovered through a FAC, which is updated quarterly to reflect actual costs incurred to supply electricity to customers.

Political Action

The NiSource Political Action Committee ("NiPAC") provides our employees a voice in the political process. NiPAC is a voluntary, employee driven and funded political action committee, and NiPAC makes bipartisan political contributions to local, state and federal candidates where permitted and in accordance with established guidelines. Consistent with our commitments and our approach to engagement, the NiPAC leadership committee members evaluate candidates for support on issues important to our business.

Environmental and Safety Matters

PHMSA Legislation and Regulations

To fulfill our vision of being a trusted energy provider, we follow safety practices required by regulations and we implement our Safety Management System ("SMS"). SMS serves as the framework to identify and reduce risks and ensure consistent safety processes, procedures and operations across the organization.

As directed by law in the Protecting Our Infrastructure of Pipelines and Enhancing Safety (PIPES) Act of 2020, PHMSA has revised, and continues to revise, the pipeline safety regulations focused on public safety and environmental hazard mitigation. Specific areas of focus for upcoming rulemaking include leak detection and repair criteria (the "LDAR" rule) and regulations that require operators to upgrade their existing low-pressure regulating stations with enhanced safeguards and update distribution integrity management plans, emergency response plans, and operation and maintenance plans (the Safety of Gas Distribution Pipelines, or "SGDP" rule).

In May 2023, PHMSA proposed regulatory revisions under the PIPES Act of 2020 to minimize methane emissions and improve public safety. Under the proposed revisions, our subsidiaries would be required to detect and repair an increased number of gas leaks, reduce the time to repair leaks, increase leak survey, and expand our existing advanced leak detection program. In January 2025, PHMSA submitted a final LDAR rule to the Federal Register and is currently suspended.

In September 2023, PHMSA proposed additional regulatory revisions under the PIPES Act of 2020 to enhance distribution system safety through equipment and procedural expectations in the form of the SGDP rule. Operators will be required to incorporate additional protections for low pressure distribution systems that prevent over-pressurization, amend construction procedures designed to minimize the risk of incidents caused by system over-pressurization, and update distribution integrity management programs to cover and prepare for over-pressurization incidents. PHMSA did not progress the SGDP rulemaking in 2024.

We continue to evaluate and monitor PHMSA legislation and regulations but cannot predict the impact of changing pipeline safety regulations on our business at this time.

Climate Change Issues

Physical Climate Risks. Increased frequency of severe and extreme weather events associated with climate change could materially impact our facilities, energy sales, and results of operations. We are unable to predict these events. However, we perform assessments of physical risk, including physical climate risk, to our business. More extreme and volatile temperatures, increased storm intensity and flooding, and more volatile precipitation leading to changes in lake and river levels are among the weather events that are most likely to impact our business. Efforts to mitigate these physical risks continue to be implemented.

ITEM 1. BUSINESS

NiSource Inc.

Transition Climate Risks and Opportunities. We actively engage with and monitor the impact that proposed legislative and regulatory programs related to GHG emissions would have on our business. Refer to Item 1A. Risk Factors, "Operational Risks," of this Annual Report on Form 10-K for further detail.

Regarding federal policies, we continue to monitor the status of climate change-related legislation and regulation, including the IIJA, IRA, and EPA's Waste Emissions Charge for Petroleum and Natural Gas systems. We have identified and pursued potential opportunities associated with the IIJA and the IRA that align with our strategy. These opportunities include tax incentives for renewable generation and storage projects, tax credit transferability and grant funding for grid resiliency, hydrogen hubs and leak detection. The new federal administration has signaled through executive actions a desire to roll-back several climate-related policies including funding for IIJA and IRA programs. We continue to evaluate and monitor how these changes will impact our business.

In May 2024, the EPA published final greenhouse gas standards and guidelines for fossil fuel-fired power plants. The rules are not expected to impact NIPSCO's existing electric generation, but, depending on the outcome of ongoing litigation and potential future changes to the rules, may impose certain operational limitations on other existing and new electric generation. Through the 2024 NIPSCO IRP process, we assessed that cost to electric customers would be approximately $675 million greater due to these rules.

We also continue to monitor evolving state policies related to GHG emissions. The Climate Solutions Now Act of 2022 requires Maryland to reduce GHG emissions by 60% by 2031 (from 2006 levels), and it requires the state to reach net zero emissions by 2045. The Maryland Department of the Environment ("MDE") adopted a plan to achieve its 2031 goal and is required to adopt a plan for their 2045 net zero goal by 2030. The Act also enacts a state policy to move to broader electrification of both existing buildings and new construction. In December 2024, the Maryland Department of the Environment issued updated final Building Energy Performance Standards, which would require net zero direct greenhouse gas emissions from large buildings by 2040 with interim targets, or payments of an alternative compliance fee. Columbia of Maryland is advocating for compliance pathways that use RNG, hydrogen, new technologies and emissions offsets. Under an executive order, Maryland is also developing a Clean Heat Standard and a Zero-Emission Heating Equipment Standard that are intended to transition gas appliances to electric heat pumps. Separately, the PSC has also initiated a proceeding related to Near-Term, Priority Actions and Comprehensive, Long-Term Planning for Maryland's Gas Companies. Columbia of Maryland cannot predict the final impact of these policies on our business at this time.

Net Zero Goal. In November 2022, we announced a goal of net zero greenhouse gas emissions by 2040, covering both Scope 1 and Scope 2 GHG emissions ("Net Zero Goal"). Our Net Zero Goal builds on greenhouse gas emission reductions achieved to-date. We plan to achieve our Net Zero Goal primarily through the continuation and enhancement of existing programs, such as retiring and replacing coal-fired electric generation with low- or zero-emission electric generation, ongoing pipe replacement and modernization programs, and deployment of advanced leak-detection technologies. In addition, we plan to advance other low- or zero-emission energy resources and technologies, which may include hydrogen, renewable natural gas, long-duration storage, and/or deployment of carbon capture and utilization technologies, if and when these become technologically and economically feasible. Carbon offsets and renewable energy credits may also be used to support achievement of our Net Zero Goal. As of the end of 2023, we had reduced Scope 1 GHG emissions by approximately 72% from 2005 levels.

Our greenhouse gas emissions projections, including achieving a Net Zero Goal, are subject to various assumptions that involve risks and uncertainties, and did not include any assumptions related to data center development and associated load growth. We remain committed to our Net Zero Goal, however, certain of our interim goals may evolve as we assess and respond to business opportunities such as data centers. Achievement of our Net Zero Goal by 2040 will require supportive regulatory and legislative policies, favorable stakeholder environments and advancement of technologies that are not currently economically or technologically feasible to deploy at scale, as well as execution of our business plan. Otherwise, our actual results or ability to achieve our Net Zero Goal, including by 2040, may differ materially.

As discussed in Management's Discussion within "Results and Discussion of Operations - NIPSCO Operations," NIPSCO continues to execute its electric generation transition consistent with the preferred pathways identified in its 2018, 2021 and 2024 Integrated Resource Plans. Additionally, as discussed in Management's Discussion within "Executive Summary - Energy Transition" and "Liquidity and Capital Resources - Regulatory Capital Programs," our natural gas distribution companies are lowering methane emissions by replacing aging infrastructure, which also increases safety and reliability for customers and communities.

ITEM 1. BUSINESS

NiSource Inc.

Human Capital

Human Capital Management Governance and Organizational Practices. The Compensation and Human Capital Committee ("C&HC Committee") of our Board of Directors (the "Board") is primarily responsible for assisting the Board in overseeing our human capital management practices. The C&HC Committee reviews our human capital management function and programs. The review of related procedures, programs, policies and practices allows the committee to make recommendations to management with respect to equal employment opportunity, employee engagement, organizational health, and talent management.

Human Capital Goals and Objectives. We have aligned our human capital goals to achieve overall company strategic and operational objectives by driving an enhanced talent strategy, elevating support for front-line leaders, fostering a culture of rigor and accountability, and strengthening our human resource function. We aspire to be an employer of choice, in part, through embedding inclusion throughout the enterprise and creating an enviable employee experience.

Workforce Composition. As of December 31, 2024, we had 7,687 full-time and 59 part-time active employees (i.e., not interns, not on leave or disability). Of our total workforce, 32% were subject to collective bargaining agreements with various labor unions. These collective bargaining agreements were renegotiated in 2021 and 2023 and expire in 2026 and 2027, respectively.

We foster an enviable work environment where all employees are energized. In efforts to become an employer of choice, we have developed sourcing strategies to attract and retain the most qualified talent. Our executive leadership team is characterized by a diverse composition, with 75% representation from both people of color ("POC") and females. We have increased our overall population of females and POC in 2024.

In 2024, our Diversity of Slate process supported our talent acquisition team filling 1,565 roles with 831 external candidates. These external hires included 34% being filled with POC and 40% being filled with female candidates. These sourcing efforts led our organization across all businesses to make progress toward a workforce composition that embraces different perspectives.

Our employee resource groups (ERGs) serve to create a culture of inclusion through their engagement of all employees throughout the year. We continue to develop ERG leaders to equip employees with the necessary tools to further support our efforts for advancement and strengthen our inclusive workplace. A key area for us has been our implementation and development of programs to drive higher retention and engagement of our employees, focusing on inclusive leadership training for Directors and Managers in the organization. Our commitment is grounded in the core belief that our purpose extends far beyond our primary role as a utility company.

We are committed to providing equal employment opportunities in each of our companies to all employees and applicants without regard to race, color, religion, national origin or ancestry, veteran status, disability, gender, age, marital status, sexual orientation, gender identity, genetic information, or any protected group status as defined by law. The input provided by our increasingly diverse workforce will continue to strengthen our corporate culture as well as drive constructive changes within our company to improve our operational strategies, enhance the quality of the services we provide, and increase revenue.

Talent Attraction. To recruit and hire individuals with a variety of skills, talents, backgrounds and experiences, we value and cultivate relationships with community and diversity outreach partners. We also target job fairs, including those focused on people of color, veteran, and female candidates while also partnering with local colleges and universities to identify and recruit qualified applicants.

Similar to other companies, we have focused on creating a flexible, agile model for roles that can be performed in a more remote setting. Our hybrid model recognizes differing ways of working; onsite, hybrid and remote. Most of our workforce is onsite and our hybrid and remote roles provide different avenues of working and seeking talent across our footprint. Hybrid employees work in a NiSource facility at least twice a week. This in-office presence supports colleague connection, development, in-person mentoring, and broader team building.

Talent Development and Retention. We offer leadership development programs to enhance the behaviors and skills of our existing and future leaders. In 2024, we had participation from employees of all levels. We also offer extensive technical and non-technical employee development training programs.

NiSource Inc.

We strive to provide promotion and advancement opportunities for employees. In 2024, for all leadership positions at the supervisor and above level posted externally, we filled 64% with internal employees. We also develop and implement targeted development action plans to increase succession candidate readiness for leadership roles. Additionally, we monitor the risk and potential impact of talent loss and take action to increase retention of top talent. Retention in 2024 was 93%. We calculate retention as 100 minus the total number of separations divided by the average headcount for the annual period. These separations break down into involuntary separations (2%), resignations (3%), and retirements (2%).

Succession Planning. We perform succession planning annually for officer level positions to ensure that we develop and sustain a strong bench of talent capable of performing at the highest levels. Talent is identified, and potential paths of development are discussed, to ensure that employees have an opportunity to build their skills to be well-prepared for future roles. We maintain formal succession plans for our CEO and key officers. The succession plan for our CEO is reviewed by the Environmental, Social, Nominating and Governance Committee and the succession plans for key officers (other than the CEO) and critical roles are reviewed by the Compensation and Human Capital Committee annually or more frequently as needed.

Employee and Workplace Health and Safety. We have several programs to support employees, and their families' well-being. These programs include competitive medical, dental, vision, life and long-term disability programs, including employee health savings account company contributions, telemedicine services, Employee Assistance Program, Integrated Health Management navigation services, and paid time off including wellness, sick/disability, parental leave, and illness in family days.

We also have a robust program to support employees, contractors and public safety, which is led by our Chief Safety Officer and is under the oversight of the Safety, Operations, Regulatory and Policy Committee of our Board.

Culture and Engagement. Our culture is another important aspect of our ability to advance our strategic and operational objectives. In addition to recruiting, development and retention programs described above, we also invest in internal communications programs, including in-person and virtual learning and networking opportunities, as well as regular town hall communications to employees. We measure and monitor organizational health and employee engagement through various channels including employee lifecycle, pulse, and census surveys.

To instill and reinforce our values and culture, we require our employees to participate in regular training on ethics and compliance topics each year, including raising concerns, treating others with respect, preventing discrimination in the workplace, anti-bribery and corruption, data protection, unconscious biases, harassment, conflicts of interest, and how to use the anonymous ethics and compliance hotline. All employees receive training on our Code of Business Conduct annually or more frequently if there is a material change in content. Because of this training and other programs, we have learned from our most recent employee survey that our employees know what ethical violations look like and how to report them. Our Code of Business Conduct is designed to ensure that our employees adhere to legal and regulatory requirements, mitigate risks, and promote ethical behavior. Our ethics program is led by leadership tone at the top, policies and procedures, regular training and communication, monitoring and auditing, and a system for reporting and addressing violations. Our business ethics program, including the employee training program, is reviewed annually by our executive leadership team and the Audit Committee of our Board of Directors.

Our Compensation and Human Capital Committee reviews reports from our Chief Human Resources Officer on employee engagement and corporate culture. Our Board reviews results and action plans related to our enterprise-wide comprehensive employee engagement survey. Our executive leadership team, including our CEO, communicates directly and regularly with all employees on timely ethics topics through electronic messages, coffee chats, and all-employee town hall meetings. These communications emphasize the importance of our values and culture in the workplace.

INFORMATION ABOUT OUR EXECUTIVE OFFICERS

NISOURCE INC.

The following is a list of our Executive Officers, including their names, ages, offices held and other recent business experience.

Name	Age	Office(s) Held in Past 5 Years
Lloyd M. Yates	64	President and Chief Executive Officer of NiSource since February 2022 and Director since March 2020
		Executive Vice President, Customer and Delivery Operations, and President, Carolinas Region, of Duke Energy Corporation from 2014 to 2019
Shawn Anderson	43	Executive Vice President and Chief Financial Officer of NiSource since March 2023
		Senior Vice President and Chief Strategy and Risk Officer from June 2020 to March 2023
		Vice President, Strategy and Chief Risk Officer from January 2019 to May 2020
Melody Birmingham	53	Executive Vice President, and President, NiSource Utilities of NiSource since March 2023
		Executive Vice President, Chief Innovation Officer of NiSource from July 2022 to March 2023
		Senior Vice President and Chief Administrator Officer of Duke Energy Corporation from May 2021 to June 2022
		Senior Vice President, Supply Chain and Chief Procurement Officer of Duke Energy Indiana from 2018 to April 2021
William Jefferson, Jr	63	Executive Vice President, Chief Operating and Safety Officer of NiSource since May 2024
		Executive Vice President, Operations and Chief Safety Officer of NiSource from July 2022 to May 2024
		Station Director at STPNOC, Wadsworth, Texas, from 2020 to May 2022 and Vice President in 2022
Michael S. Luhrs	52	Executive Vice President, Strategy and Risk and Chief Commercial Officer of NiSource since March 2023
		Senior Vice President at Alliant Energy from 2022 to March 2023
		Vice President at Duke Energy Corporation from 2013 to 2022
Kimberly S. Cuccia	41	Senior Vice President, General Counsel and Corporate Secretary of NiSource since April 2022
		Vice President, Interim General Counsel and Corporate Secretary of NiSource from December 2021 to April 2022
		Vice President and Deputy General Counsel, Regulatory, of NiSource Corporate Services Company, from January 2021 to December 2021
		Vice President and General Counsel of Columbia Gas of Massachusetts and of NiSource Corporate Services Company, from 2019 to 2020
Melanie B. Berman	54	Chief Human Resources Officer and Senior Vice President, Administration of NiSource since May 2024
		Senior Vice President and Chief Human Resources Officer of NiSource from June 2021 to May 2024
		Executive Vice President and Chief Human Resources Officer of The Michaels Companies, Inc. from 2020 to 2021
Gunnar J. Gode	50	Vice President, Chief Accounting Officer and Controller of NiSource since July 2020
		Vice President and Controller of Washington Gas from March 2019 to 2020

ITEM 1A. RISK FACTORS

NiSource Inc.

Our operations and financial results are subject to various risks and uncertainties, including those described below, that could adversely affect our business, financial condition, results of operations, cash flows, and the market price of our common stock.

OPERATIONAL RISKS

We may not be able to execute our business plan or growth strategy, including utility infrastructure investments, or business opportunities, such as data center development and related generation sources and transmission capabilities to meet potential load growth.

Operational, financial or regulatory conditions may result in our inability to execute our business plan or growth strategy, including investments related to natural gas and electric distribution and transmission infrastructure investments and our electric generation projects. Additionally, operational, financial or regulatory conditions may result in our inability to manage the development and implementation connected to the complex business opportunity associated with growing interest in data centers from existing and potential customers.

Our enterprise-wide transformation roadmap initiatives identify and enable long-term sustainable capability enhancements, cost optimization improvements, technology investments and work process optimization, and these initiatives have increased the volume and pace of change and may not be effective as it continues. Our customer and regulatory initiatives may not achieve planned results. Utility infrastructure investments may not materialize, may cease to be achievable or economically viable and may not be successfully completed. Furthermore, we are evaluating the potential for data center development in our service territories, including ways to effectively manage the potential power demand, generation sources, and transmission capabilities to meet potential load growth from any data center customer, while at the same time focusing on our environmental goals. We expect that management of load growth would require new generation and transmission capabilities. Natural gas may cease to be viewed as an economically and environmentally attractive fuel. Certain environmental activist groups, investors and governmental entities continue to oppose natural gas delivery and infrastructure investments because of perceived environmental impacts associated with the natural gas supply chain and end use. Energy conservation, energy efficiency, distributed generation, energy storage, policies favoring electric heat over gas heat and other factors may reduce demand for natural gas and electricity. In addition, we consider acquisitions or dispositions of assets or businesses, JVs, and mergers from time to time as we execute on our business plan and growth strategy. As data center opportunities evolve and develop, we may also enter into arrangements and agreements with customers and potential customers that require us to invest capital related to the data center development and related generation sources and transmission capabilities before we receive any potential return. Any of these circumstances could adversely affect our business, results of operations and growth prospects. Even if our business plan, growth strategy, and/or business opportunities are executed, there is still risk of, among other things, human error in maintenance, installation or operations, shortages or delays in obtaining equipment, including as a result of transportation delays and availability, labor availability and performance below expected levels (in addition to the other risks discussed in this section). We are currently experiencing, and expect to continue to experience, supply chain challenges, including labor availability issues, impacting our ability to obtain materials for our gas and electric projects, as well as our ability to ensure timely completion.

Data center growth in our service territories, including a focus on northern Indiana, while providing growth opportunities that enhance our business strategy, provide significant financial, operational, and regulatory risks that must be effectively managed.

As we evaluate business opportunities presented by the data center development in our territories, including a focus on northern Indiana, we face a variety of challenges including accurately predicting future power needs of data centers due to rapidly changing technology and market dynamics, managing the potential power demand, generation sources, and transmission capabilities to meet potential load growth from any data center customer, financing the capital investment needed to build and maintain the necessary infrastructure to support data center development, managing the possible environmental impact of the potential increased power demand while remaining focused on our Net Zero Goal, and evaluating and complying with evolving regulations related to data center development. As we evaluate the potential for data center development in our service territories, we must effectively manage these financial, operational and regulatory risks.

Our distribution, transmission and generation activities involve a variety of inherent hazards and operating risks, including potential public safety risks.

Our gas distribution and transmission, electric generation, transmission and distribution activities, involve a variety of inherent hazards and operating risks, including, but not limited to, gas leaks and over-pressurization, downed power lines, stray electrical voltage, excavation or vehicular damage to our infrastructure, outages, environmental spills, mechanical problems, damage from weather events, and other incidents, which could cause substantial financial losses. These hazards and risks have resulted and may result in serious injury or loss of life to employees and/or the general public, significant damage to property,

environmental pollution, impairment of our operations, adverse regulatory rulings and reputational harm, which in turn could lead to substantial business and financial losses. The location of pipeline facilities, including regulator stations, liquefied natural gas and underground storage, or generation, transmission, substation and distribution facilities near populated areas, including residential areas, commercial business centers and industrial sites, could increase the level of damages resulting from such incidents. Hazardous incidents have subjected and may subject us to both civil and criminal litigation or administrative or other legal proceedings from time to time, which could result in substantial monetary judgments, fines, or penalties against us, be resolved on unfavorable terms, and require us to incur significant operational expenses. The occurrence of incidents has in certain instances adversely affected and could in the future adversely affect our reputation, cash flows, financial position and/or results of operations. We maintain insurance against some, but not all, of these risks and losses.

We currently conduct and may conduct in the future certain operations through a JV arrangement involving third-party investors that may result in operational impasses or litigation, including business delays as a result of such arrangements.

We have and may enter into JV arrangements involving third-party investors, including the NIPSCO Minority Interest Transaction. As part of a JV arrangement, third-party investors may hold certain protective rights that may impact our ability to make certain decisions, restricting our operational and corporate flexibility. Any such third-party investors may have interests and objectives which may differ from ours, we may be unable to cause these third parties to take action that we believe would be in the JV's best interest, and, accordingly, disputes may arise that may result in operational impasses or litigation, including business delays.

Failure to adapt to advances in technology, including alternative energy sources, and changes in laws or regulations to support such advances in technology or alternative energy sources, and our ability to manage such related costs could make us less competitive.

A key element of our electric business model includes generating power at central station power plants and transmitting that power to customers to achieve economies of scale and produce power at a competitive cost. We continue to transition our generation portfolio in order to implement new and diverse technologies including renewable energy, distributed generation, energy storage, and implement energy efficiency programs for customers. Advances in technology and potential competition supported by changes in laws or regulations could reduce the cost of electric generation and provide retail alternatives causing power sales to decline and the value of our generating, transmission and distribution facilities to decline.

Our natural gas business model depends on widespread utilization of natural gas for space heating as a core driver of revenues. Alternative energy sources, new technologies or alternatives to natural gas space heating, including cold climate heat pumps and/or efficiency of other products, and potential competition supported by changes in laws or regulations could reduce demand and increase customer attrition, which could impact our ability to recover on our investments in our gas distribution assets.

Our future success will depend, in part, on our ability to anticipate and successfully adapt to technological changes, to offer services that meet customer demands and evolving industry standards, including environmental impacts associated with our products and services, and to recover all, or a significant portion of, remaining investments in retired assets. A failure by us to effectively adapt to changes in technology, successfully implement such changes, and manage the related costs could harm the ability of our products and services to remain competitive in the marketplace and could have a material adverse impact on our business, results of operations and financial condition. Furthermore, if these changes do not provide the anticipated benefits or meet customer demands, such failure could materially adversely affect our business model as well as impact results of operations and financial condition.

Increased dependency on technology may hinder our business operations and adversely affect our financial condition and results of operation if such technology fails.

We use a variety of technological tools and systems including both Company-owned information technology and technological services provided by outside parties. These tools and systems support critical functions including scheduling and dispatching of service technicians, automated meter reading systems, customer care and billing, operational plant logistics, management reporting and external financial reporting. The failure of these or other similarly important technologies, or our inability to have these technologies supported, updated, expanded, recovered (including timely recovered), or integrated into other technologies, could hinder our business operations and adversely impact its financial condition and results of operations. Although the Company has, when possible, developed alternative sources of technology and built redundancy into its computer networks and tools, there can be no assurance that these efforts would protect against all potential issues related to the loss of any such technologies.

Aging infrastructure may lead to disruptions in operations and increased capital expenditures and maintenance costs.
We have risks associated with aging electric and gas infrastructure. These risks can be driven by threats such as, but not limited to, electrical faults, mechanical failure, internal corrosion, external corrosion, ground movement and stress corrosion and/or cracking. The age of these assets may result in a need for replacement, a higher level of maintenance costs or unscheduled outages, despite efforts by us to properly maintain or upgrade these assets through inspection, scheduled maintenance and capital investment. In addition, the nature of the information available on aging infrastructure assets, which in some cases is incomplete, may make the operation of the infrastructure, inspections, maintenance, upgrading and replacement of the assets particularly challenging. Missing or incorrect infrastructure data may lead to (1) difficulty properly locating facilities, which can result in excavator damage and operational or emergency response issues, (2) configuration and control risks associated with the modification of system operating pressures in connection with turning off or turning on service to customers, which can result in unintended outages or operating pressures and (3) other potential risks related to missing or incorrect infrastructure data. Also, additional maintenance and inspections are required in some instances to improve infrastructure information and records and address emerging regulatory or risk management requirements, resulting in increased costs.

Supply chain issues related to shortages of materials, labor and transportation logistics may lead to delays in the maintenance and replacement of aging or damaged infrastructure, which could increase the probability and/or impact of a public safety incident. We lack diversity in suppliers of some gas materials. While we have implemented contractual protections with suppliers and stockpile some materials in inventory for such supply risks, we may not be effective in ensuring that we can obtain adequate emergency supply on a timely basis in each state, that no compromises are being made on quality and that we have alternate suppliers available. The failure to operate our assets as desired could result in interruption of electric service, major component failure at generating facilities and electric substations, gas leaks and other incidents, and an inability to meet firm service and compliance obligations, which could adversely impact revenues, and could also result in increased capital expenditures and maintenance costs, which, if not fully recovered from customers, could negatively impact our financial results.

We may be unable to obtain insurance on acceptable terms or at all, and the insurance coverage we do obtain may not provide protection against all significant losses.
Our ability to obtain insurance, as well as the cost and coverage of such insurance, is impacted by various events and developments affecting our industry and the financial condition and underwriting considerations of insurers. For example, some insurers have discontinued underwriting certain carbon-intensive energy-related businesses such as those in the coal industry or excluded coverage for specific perils such as wildfires or punitive damage risks. Certain perils, such as cyber liability, are now being excluded from some master policies for property and casualty insurance, requiring, where we have the ability, procurement of additional policies to maintain consistent coverage at an additional cost. Specific natural catastrophe events, such as hail and tornado, may not be covered with the same limits as other perils in certain property policies, as full coverage for these events is unavailable in the marketplace without costly specialty policies. Insurance coverage may not continue to be available at limits, rates or terms acceptable to us. In addition, our insurance is not sufficient or effective under all circumstances and against all hazards or liabilities to which we are subject. Certain types of damages, expenses or claimed costs, such as fines and penalties, have been and in the future may be excluded under the policies. In addition, insurers providing insurance to us may raise defenses to coverage under the terms and conditions of the respective insurance policies that could result in a denial of coverage or limit the amount of insurance proceeds available to us. Any losses for which we are not fully insured or that are not covered by insurance at all could materially adversely affect our results of operations, cash flows and financial position.

Aspects of the implementation of our electric generation strategy, including the timing of the retirement of our coal generation units or the addition of new generation resources, may be delayed and may not achieve intended results.
We intend to retire the remaining two coal units at R.M. Schahfer Generating Station by the end of 2025, two natural gas-fired peaking units at R.M. Schahfer Generating Station by the end of 2027, and the coal unit at Michigan City Generating Station by the end of 2028. These units are being replaced with a diverse, flexible, and scalable mix of incremental resources, including short-term contracted capacity resources, expanded demand side management programs, wind, solar, battery energy storage, and new natural gas peaking resources. Macro supply chain issues and U.S. federal policy actions could create uncertainty around the availability of key input materials necessary to develop and place our electric generation projects in service.

We expect renewable generation, battery energy storage and natural gas generation to be the primary ways in which we will meet our electric generation capacity and reliability obligations to the MISO market and reliably serve our customers when we retire our coal generation capacity. Any delays in the completion of such projects could create significant risks for us to reliably meet our capacity and energy obligations to MISO and to provide reliable and affordable energy to our customers. Delays to the

completion dates of our projects could also include delays in the financial return of certain investments and impact the overall timing of our electric generation transition.

Our electric generation strategy may require additional investment to meet our MISO obligations and may require significant future capital expenditures, operating costs and charges to earnings that may negatively impact our financial position, financial results and cash flows. An inability to secure and deliver on electric generation projects has negatively impacted, and could in the future negatively impact, our generation transition timeline and could negatively impact our achievement of decarbonization goals and reputation.

Our capital projects and programs subject us to construction and supply risks, and are subject to regulatory oversight, including requirements for permits, approvals and certificates from various governmental agencies.

Our business requires substantial capital expenditures for investments in, among other things, capital improvements to our electric generating facilities, electric and natural gas transmission and distribution infrastructure, natural gas storage and other projects, including projects for environmental compliance. As we undertake these projects and programs, we may be unable to complete them on schedule or at the anticipated costs. Additionally, we may construct or purchase some of these projects and programs to capture anticipated future growth, which may not materialize, and may cause the construction to occur over an extended period of time.

Construction risks include, but are not limited to, changes in the availability or costs of materials, equipment, commodities or labor (including changes to tariffs on materials), delays caused by construction incidents or injuries, work stoppages, poor initial cost estimates, unforeseen engineering issues, and general contractors and subcontractors not performing as required under their contracts.

We are monitoring risks related to increasing delivery lead times for certain construction and other materials, increasing risk associated with the unavailability of materials due to global shortages in raw materials and issues with transportation logistics, and risk of decreased construction labor productivity in the event of disruptions in the availability of materials critical to our gas and electric operations. Our efforts to enhance our resiliency to supply chain shortages may not be effective. We continue to see increasing prices associated with certain materials, equipment and products, which impacts our ability to complete major capital projects at the cost that was planned and approved. To the extent that delays occur, costs increase, costs become unrecoverable or recovery is delayed, or we otherwise become unable to effectively manage our affordability and complete our capital projects, our business operations, results of operations, cash flows, and financial condition may be adversely affected. In addition, to the extent that delays occur on projects that target system integrity, the risk of an operational incident could increase.

Our existing and planned capital projects require numerous permits, approvals and certificates from federal, state, and local governmental agencies, including obtaining necessary rights-of-way, easements and transmissions connections, as well as complying with various environmental statutes, rules and regulations, among other items. If there is a delay in obtaining any required regulatory approvals or if we fail to obtain or maintain any required approvals or to comply with any applicable laws or regulations, we may not be able to construct or operate our facilities, we may be forced to incur additional costs or we may be unable to recover any or all amounts invested in a project. We also may not receive the anticipated increases in revenue and cash flows resulting from such projects and programs until after their completion.

A significant portion of the gas and electricity we sell is used by residential and commercial customers for heating and air conditioning. Accordingly, fluctuations in weather, gas and electricity commodity costs, and economic conditions impact customer demand.

Energy sales are sensitive to variations in weather. Forecasts of energy sales are based on “normal” weather, which represents a long-term historical average. Significant variations from normal weather resulting from climate change or other factors could have, and have had, a material impact on energy sales. Additionally, residential usage, and to some degree commercial usage, is sensitive to fluctuations in commodity costs for gas and electricity (which volatility is described in more detail in the below risk factor), whereby usage declines with increased costs which could affect our financial results. Rising gas costs could heighten regulator and stakeholder sensitivity relative to the impact of base rate increases on customer affordability. Lastly, residential and commercial customers’ usage is sensitive to economic conditions and factors such as recession, inflation, unemployment, demand and consumer confidence. Therefore, prevailing economic conditions affecting the demand of our customers may in turn affect our financial results.

ITEM 1A. RISK FACTORS

NiSource Inc.

Fluctuations in the price of energy commodities or their related transportation costs, or an inability to obtain an adequate, reliable and cost- effective fuel supply may impact our ability to meet customer demand.
Our current electric generating fleet has dependencies on coal and natural gas for fuel, and our gas distribution operations purchase and resell a portion of the natural gas we deliver to our customers. These energy commodities are subject to price fluctuations and fluctuations in associated transportation costs. We use physical hedging through the use of storage assets and use financial products in certain jurisdictions in order to offset fluctuations in commodity supply prices. We rely on regulatory recovery mechanisms in the various jurisdictions in order to fully recover the commodity costs incurred in selling energy to our customers. While we have historically been successful in the recovery of costs related to such commodity prices, there can be no assurance that such costs will be fully recovered through rates in a timely manner.

In addition, we depend on electric transmission lines, natural gas pipelines, and other transportation and storage facilities owned and operated by third parties to deliver the electricity and natural gas we sell to wholesale markets, supply natural gas to our gas storage and electric generation facilities, and provide retail energy services to our customers. If transportation is disrupted, if capacity is inadequate or if supply is interrupted due to issues at the wellhead, we may be unable to sell and deliver our gas and electric services to some or all of our customers. As a result, we may be required to procure additional or alternative electricity and/or natural gas supplies at then-current market rates, which, if recovery of related costs is disallowed, could have a material adverse effect on our businesses, financial condition, cash flows, results of operations and/or prospects.

Failure to attract, retain or re-skill an appropriately qualified workforce, and maintain good labor relations, could adversely impact safety, service reliability, and customer satisfaction.
We face increased competition for talent which may result in longer hire times or increased cost due to the competitive nature of certain positions.

We operate in an industry that requires many of our employees and contractors to possess unique technical skill sets. An aging workforce without appropriate replacements, the mismatch of skill sets to future needs, the unavailability of talent for internal positions and the unavailability of contract resources may lead to operating challenges or increased costs. These operating challenges include lack of resources, loss of knowledge and a lengthy time period associated with skill development. For example, certain skills, such as those related to construction, maintenance and repair of transmission and distribution systems, are in high demand and have a limited supply. Current and prospective employees may determine that they do not wish to work for us due to market, economic, employment or other conditions, including those related to organizational changes as described in the risk factor below.

Further, as part of our strategic plan, which includes enhanced technology, transmission and distribution investments, and a reduction in reliance on coal-fired generation, we will need to attract and retain personnel that are qualified to implement such a strategy and may need to retrain or re-skill certain employees to support our long-term objectives. Additionally, successful implementation of our strategic plan is dependent on our ability to recruit and retain key executive officers to oversee its progress.

A significant portion of our workforce is subject to collective bargaining agreements. Our collective bargaining agreements are generally negotiated on an operating company basis with some companies having multiple bargaining agreements, which may span different geographies. Any failure to reach an agreement on new labor contracts or to renegotiate these labor contracts might result in strikes, boycotts or other labor disruptions. Our workforce continuity plans may not be effective in avoiding work stoppages that may result from labor negotiations or mass resignations. Labor disruptions, strikes or significant negotiated wage and benefit increases, whether due to union activities, employee turnover or otherwise, could have a material adverse effect on our businesses, results of operations and/or cash flows.

Failure to attract, retain, or re-skill qualified employees, including the ability to transfer significant internal historical knowledge and expertise to the new employees, could result in a loss of momentum, loss of high-level employees to our peers and could materially adversely affect our business, results of operations, cash flow and financial condition. If we are unable to successfully attract and retain an appropriately qualified workforce and maintain satisfactory labor relations, safety, service reliability, and customer satisfaction, our results of operations could be adversely affected.

If we cannot effectively manage new initiatives and organizational changes, we will be unable to address the opportunities and challenges presented by our strategy and the business and regulatory environment.
In order to execute on our sustainable growth strategy and enhance our culture of ongoing continuous improvement, we must effectively manage the complexity and frequency of new initiatives and organizational changes. The organizational changes

from our transformation initiatives have put short-term pressure on employees due to the volume and pace of change and, in some cases, the loss of personnel. Front-line workers are being impacted by the variety of process and technology changes that are currently in progress.

If we are unable to make decisions quickly, assess our opportunities and risks, and successfully implement new governance, managerial and organizational processes as needed to execute our strategy in this increasingly dynamic and competitive business and regulatory environment, our financial condition, results of operations and relationships with our business partners, regulators, customers, employees and stockholders may be negatively impacted.

Actions of activist stockholders could negatively affect our business and stock price and cause us to incur significant expenses.

We may be subject to actions or proposals from activist stockholders or others that may not be aligned with our long-term strategy or the interests of our other stockholders. Our response to suggested actions, proposals, director nominations and contests for the election of directors by activist stockholders could disrupt our business and operations, divert the attention of our board of directors, management and employees, and be costly and time-consuming. Potential actions by activist stockholders or others may interfere with our ability to execute our strategic plans; create perceived uncertainties as to the future direction of our business or strategy; cause uncertainty with our regulators; make it more difficult to attract and retain qualified personnel; and adversely affect our relationships with our existing and potential business partners. Any of the foregoing could adversely affect our business, financial condition and results of operations. Also, we may be required to incur significant fees and other expenses related to responding to stockholder activism, including for third-party advisors. Moreover, our stock price could be subject to significant fluctuation or otherwise be adversely affected by the events, risks and uncertainties of any stockholder activism.

We outsource certain business functions to third-party suppliers and service providers, and may be impacted by substandard performance or quality by third parties.

Utilities rely on extensive networks of business partners and suppliers to support critical enterprise capabilities across their organizations. Like other companies in the utilities industry, we outsource certain services to third parties in areas including construction services, information technology, materials, fleet, environmental, operational services, corporate and other areas. We have seen, and may see in the future, slowing deliveries from suppliers and in some cases materials and labor shortages. In addition to delays and unavailability, at times, outsourcing of services to third parties could expose us to inferior service quality or substandard deliverables, which may result in non-compliance (including with applicable legal requirements and industry standards), interruption of service, accidents, or reputational harm, which could negatively impact our business, financial condition and results of operations. The nature of indirect supply chain, including a potential lack of control or certain visibility into sourcing by vendors, may also impact our ability to serve customers in a safe, reliable and cost-effective manner. These risks include the risk of operational failure, reputation damage, disruption due to new supply chain disruptions, exposure to significant commercial losses and fines and poorly positioned and distressed suppliers. If we continue to see delayed deliveries and shortages or if any other difficulties in the operations of these third-party suppliers and service providers, including their systems, were to occur, they could adversely affect our results of operations, or adversely affect our ability to work with regulators, unions, customers, or employees.

A cyber-attack or security breach on any of our or certain third-party technology systems, including but not limited to information systems, infrastructure, software and hardware, upon which we rely may adversely affect our ability to operate, could lead to a loss or misuse of confidential and proprietary information, or potential liability.

We are reliant on technology to run our business, which is dependent upon technology systems to process critical information necessary to conduct various elements of our business, including the generation, transmission and distribution of electricity; operation of our gas pipeline facilities; and the recording and reporting of commercial and financial transactions to regulators, investors and other stakeholders. In addition to general information and cybersecurity risks that all large corporations face (e.g., ransomware, malware, unauthorized access attempts, phishing attacks, malicious intent by insiders, third-party software vulnerabilities and inadvertent disclosure of sensitive information), the utility industry faces evolving and increasingly complex cybersecurity risks associated with protecting electric grid and natural gas infrastructure as well as sensitive and confidential customer and employee information. Deployment of new business technologies, along with maintaining legacy technology, represents a large-scale opportunity for attacks on our information systems and confidential customer and employee information, as well as on the integrity of the electric grid and the natural gas infrastructure. Increasing large-scale corporate cyber-attacks in conjunction with more sophisticated threats continue to challenge utility companies. Additionally, international conflicts, as well as increased surveillance activity from global threat actors, has increased the likelihood of a cyber-attack or security breach on critical infrastructure systems.

Additionally, our information systems experience ongoing, often sophisticated, cyber-attacks or security breaches by a variety of sources, including foreign sources, with the apparent aim to breach our cyber-defenses. While we have implemented and maintain a cybersecurity program designed to protect our information technology, operational technology, and data systems from such cyber-attacks or security breaches, our cybersecurity program does not prevent all breaches, cyber-attack or security breach incidents. We have experienced an increase in the number of attempts by external parties to access our networks or our company data without authorization. We have experienced, and expect to continue to experience, cybersecurity intrusions and attacks or security breaches to our information systems. To our knowledge, none of these intrusions or attacks have resulted in a material cybersecurity intrusion or data breach. The risk of a disruption or breach of our operational technology, or the compromise of the data processed in connection with our operations, through cybersecurity breach or ransomware attack has increased as attempted cyber-attacks or security breaches have advanced in sophistication and number around the world. Technological complexities combined with advanced cyber-attack or security breach techniques, lack of cybersecurity hygiene and human error can result in a cybersecurity incident, such as a ransomware attack. Supplier non-compliance with cybersecurity controls can also result in a cybersecurity incident. We are aware of vendor cybersecurity incidents that have impacted our business, although no such events have had a material impact. Cyber-attacks or security breaches can occur at any point in the supply chain or with any suppliers, and future supplier non-compliance with cybersecurity controls could result in material cybersecurity incidents. In addition, we use unmanned aircraft systems (UAS) or drones in our business operations. UASs are also being used for malicious activities and the cybersecurity risk in connection with operating UASs is increasing.

In addition, we collect and retain personally identifiable information of our customers and employees. Customers and employees expect that we will adequately protect their personal information.

A cybersecurity breach of our information systems or operational technology, or a cybersecurity breach of the information systems of our customers, suppliers or others with whom we do business, could, among other things, (i) adversely impact our ability to safely and reliably deliver electricity and natural gas to our customers through our generation, transmission and distribution systems and potentially negatively impact our compliance with certain mandatory reliability and gas flow standards, (ii) subject us to reputational and other harm or liabilities associated with theft or inappropriate release of certain types of information such as system operating information or information, personal or otherwise, relating to our customers or employees, (iii) impact our ability to manage our businesses, and/or (iv) subject us to legal and regulatory proceedings and claims from third parties, in addition to remediation costs, any of which, in turn, could have a material adverse effect on our businesses, cash flows, financial condition and/or results of operations. Although we do maintain cybersecurity insurance, it is possible that such insurance will not adequately cover any losses or liabilities we may incur as a result of a cybersecurity incident.

Compliance with and changes in cybersecurity requirements have a cost and operational impact on our business, and failure to comply with such laws and regulations could adversely impact our reputation, results of operations, financial condition and/or cash flows.

The legal and regulatory environment surrounding cybersecurity and privacy is increasingly demanding. As cyber-attacks or security breaches are becoming more sophisticated, critical infrastructure assets, including pipelines and electric infrastructure, may be specifically targeted. In 2021, the TSA announced two new cybersecurity directives in response to a ransomware attack on the Colonial Pipeline that occurred earlier in the year. These directives, including updates or amendments to such TSA directives, require critical pipeline owners to comply with mandatory reporting measures, designate a cybersecurity coordinator, provide vulnerability assessments, and ensure compliance with certain cybersecurity requirements. In November 2024, the TSA issued a Notice of Proposed Rulemaking (NPRM) that would mandate cyber risk management and reporting requirements for the pipeline industry. Such directives or additional legal requirements may require expenditure of significant additional resources to respond to cyber-attacks or security breaches, to continue to modify or enhance protective measures, or to assess, investigate and remediate any critical infrastructure security vulnerabilities. Increased costs and the operational impacts of compliance and changes in cybersecurity requirements, including any failure to comply with government regulations or any failure in our cybersecurity protective measures may result in enforcement actions, all of which may have a material adverse effect on our business, results of operations and financial condition. In addition, there is no certainty that costs incurred related to securing against threats will be recovered through rates.

The impacts of natural disasters, acts of terrorism, acts of war, civil unrest, accidents, public health emergencies or other catastrophic events may disrupt operations and reduce the ability to service customers.

A disruption or failure of natural gas distribution systems, or within electric generation, transmission or distribution systems, in the event of a hurricane, tornado, wildfire, flood, or other major weather event, or terrorist attack, acts of war, international

military invasions, including the political and economic disruption and uncertainty related to such terrorist attack, acts of war, or international military invasions, civil unrest, accident, public health emergency (e.g. pandemic), or other catastrophic event could cause delays in completing sales, providing services, or performing other critical functions. We have experienced disruptions in the past from tornadoes, hurricanes and remnants of hurricanes and other events of this nature. Also, companies in our industry face a heightened risk of exposure to and have experienced acts of terrorism and vandalism. Our electric and gas physical infrastructure may be targets of physical security threats or terrorist activities that could disrupt our operations. We have increased security given the current environment and may be required by regulators or by the future threat environment to make investments in security that we cannot currently predict. In addition, the supply chain constraints that we are experiencing could impact our ability to timely restore services. The occurrence of such events could materially adversely affect our business, financial position and results of operations. In accordance with customary industry practice, we maintain insurance against some, but not all, of these risks and losses. As a result, the amount and scope of insurance coverage maintained against losses resulting from any such event may not be sufficient to cover such losses or otherwise adequately compensate for any business disruptions that could result.

We are exposed to significant reputational risks, which make us vulnerable to a loss of cost recovery, increased litigation and negative public perception.

As a utility company, we are subject to adverse publicity focused on the actual or perceived reliability or affordability of our services, the speed with which we are able to respond effectively to electric outages, natural gas leaks or events and related accidents and similar interruptions caused by storm damage, physical or cybersecurity incidents, or other unanticipated events, as well as our own or third parties' actions or failure to act. We are subject to prevailing labor markets and potential high attrition, which may impact the speed of our customer service response. We are also facing supply chain challenges, the impacts of which may adversely impact our reputation in several areas as described elsewhere in these risk factors. We are also subject to adverse publicity related to actual or perceived environmental practices or impacts, including our ability to meet the challenges posed by climate change and achieve our carbon emission reduction goals, as well as negative opinions regarding the appropriateness of such goals. If customers, legislators or regulators have or develop a negative opinion of us, this could result in less favorable legislative and regulatory outcomes or increased regulatory oversight, increased litigation and negative public perception. The foregoing may have adverse effects on our business, results of operations, cash flow and financial condition.

The physical impacts of climate change and the transition to a lower carbon future are impacting our business and could materially adversely affect our results of operations.

Climate change is exacerbating risks to our physical infrastructure by increasing the frequency of extreme weather, including temperature stresses to our electric and gas systems and equipment and storms and floods that damage infrastructure. In addition, climate change is likely to cause lake and river level changes that affect the manner in which services are currently provided and droughts or other limits on water used to supply services, and other extreme weather conditions. We have adapted and will continue to evolve our infrastructure and operations to meet current and future needs of our stakeholders. With higher frequency of these and other possible extreme weather events it may become more costly for us to safely and reliably deliver certain products and services to our customers. Further, as our generation profile increases geographically, it is potentially more vulnerable to certain weather hazards than centralized generation, thereby increasing the frequency of weather impacts to overall electric reliability. Some of these costs may not be recovered. To the extent that we are unable to recover those costs, or if higher rates arising from recovery of such costs result in reduced demand for services, our future financial results may be adversely impacted. Further, as the intensity and frequency of significant weather events increases, insurers may reprice or remove themselves from insuring risks for which the company has historically maintained insurance, resulting in increased cost or risk to us.

Our strategy may be impacted by policy and legal, technology, market and reputational risks and opportunities that are associated with the transition to a lower-carbon economy, as disclosed in other risk factors in this section. As a result of increased awareness regarding climate change, coupled with economic considerations, availability of alternative energy sources, including private solar, microturbines, fuel cells, energy-efficient buildings and energy storage devices, and regulations restricting, or imposing fees on, emissions, some consumers and companies may use less energy, meet their own energy needs through alternative energy sources or avoid expansions of their facilities, including natural gas facilities, which may result in less demand for our services. As these technologies become a more cost-competitive option, whether through cost effectiveness or government incentives and subsidies, certain customers may choose to meet their own energy needs and subsequently decrease usage of our systems and services, which may result in, among other things, our facilities becoming less competitive and economical. Further, evolving investor sentiment related to the use of fossil fuels and initiatives to restrict continued production of fossil fuels could result in a significant impact on our electric generation and natural gas businesses in the future.

ITEM 1A. RISK FACTORS

NiSource Inc.

We are unable to forecast the future of commodity markets. Some of our generation is dependent on natural gas and coal, and we pass through the costs for these energy sources to our customers. In addition, in our gas distribution business, we procure natural gas on behalf of certain customers, and we pass through the actual cost of the gas consumed. Diminished investor interest in funding fossil fuel development could reduce the amount of exploration and production of natural gas or coal, or investment in gas transmission pipelines. Reduced production and transportation of natural gas could, in the long-term, lead to supply shortages leading to baseload generation outages. Given that we pass through commodity costs to customers, this could also create the potential for regulatory questions resulting from increased customer costs, reduced fossil fuel investment, due to evolving investor sentiment, could lead to higher commodity prices and shortages impacting our generation and our reputation with regulators. Conversely, demand for our services may increase as a result of customer changes in response to climate change. For example, as the utilization of electric vehicles increases, demand for electricity may increase, resulting in increased usage of our systems and services.

Any negative views with respect to our environmental practices or our ability to meet the challenges posed by climate change from regulators, customers, investors or legislators could not only harm our reputation, but could adversely affect the perceived value of our products and services. Changes in policy to combat climate change, and technology advancement, each of which can also accelerate the implications of a transition to a lower carbon economy, may materially adversely impact our business, financial position, results of operations, and cash flows. For example, Maryland is considering policies related to the planning, practices, and future operations of natural gas suppliers in its state which could impact our business in the future.

We are subject to operational and financial risks and liabilities associated with the implementation and efforts to achieve our carbon emission reduction goals.

In November 2022, we announced our goal of reaching net zero Scope 1 and 2 greenhouse gas emissions by 2040 (the "Net Zero Goal"). Achieving the Net Zero Goal will require supportive regulatory and legislative policies, favorable stakeholder environments and advancement of technologies that are not currently economically or technologically feasible to deploy at scale, of which, the impacts and costs are not currently fully understood. NIPSCO's electric generation transition, which is outlined in the 2024 Plan, is a key element of the Net Zero Goal. Our analysis and plan for execution requires us to make a number of assumptions. These goals and underlying assumptions involve risks and uncertainties and are not guarantees. Should one or more of our underlying assumptions prove incorrect, our actual results and ability to achieve our emissions goal could differ materially from our expectations. Certain of the assumptions that could impact our ability to meet our emissions goal include, but are not limited to: the accuracy of current emission measurements, the ability to complete and implement generation alternatives to NIPSCO's coal generation and retire NIPSCO's coal facilities; the ability to implement our modernization plans for our natural gas pipelines and facilities, including construction of new pipelines and facilities; customer demand and capacity needs remaining in line with current expectations, including impacts from energy efficiency and technological innovation and adoption of alternative energy sources; the ability to effectively manage business opportunities from data center development; the ability to manage costs and supply chain risks associated with construction of electric and natural gas assets; technological innovation and costs of energy generation technologies such as wind, solar, thermal and energy storage, and of carbon abatement technologies such carbon capture solutions; regulatory approval; impacts of potential future environmental regulations or legislation, including potential GHG pricing regimes such as a carbon tax or methane fee; price, availability and regulation of carbon offsets; and price of natural gas and alternative fuels such as hydrogen. Any negative opinions with respect to these goals or our environmental practices, including our ability to meet the challenges posed by climate change and our ability to achieve our carbon emission reduction goals, or a scaling back of these goals, formed by regulators, customers, investors or legislators could harm our reputation and have an adverse effect on our financial condition.

FINANCIAL, ECONOMIC AND MARKET RISKS

We have substantial indebtedness which could adversely affect our financial condition.

Our business is capital intensive and we rely significantly on long-term debt to fund a portion of our capital expenditures and repay outstanding debt, and on short-term borrowings to fund a portion of day-to-day business operations. We had total consolidated indebtedness of $13,960.3 million outstanding as of December 31, 2024. Our substantial indebtedness could have important consequences. For example, it could:

- limit our ability to borrow additional funds or increase the cost of borrowing additional funds;
- reduce the availability of cash flow from operations to fund working capital, capital expenditures and other general corporate purposes;
- limit our flexibility in planning for, or reacting to, changes in the business and the industries in which we operate;
- lead parties with whom we do business to require additional credit support, such as letters of credit, in order for us to transact such business;
- place us at a competitive disadvantage compared to competitors that are less leveraged;

- increase vulnerability to general adverse economic and industry conditions; and
- limit our ability to execute on our growth strategy, which is dependent upon access to capital to fund our substantial infrastructure investment program.

Some of our debt obligations contain financial covenants related to debt-to-capital ratios and cross-default provisions. Our failure to comply with any of these covenants could result in an event of default, which, if not cured or waived, could result in the acceleration of outstanding debt obligations. Additionally, non-compliance with debt covenants could adversely affect our ability to obtain future borrowings and as a result materially adversely affect our business, financial condition, results of operations, and liquidity.

A drop in our credit ratings could adversely impact our cash flows, results of operation, financial condition and liquidity.

The availability and cost of credit for our businesses may be greatly affected by credit ratings. The credit rating agencies periodically review our ratings, taking into account factors such as our capital structure, earnings profile, liabilities, and overall shifts in the economy or business environment. We are committed to maintaining investment grade credit ratings; however, there is no assurance we will be able to do so in the future. Our credit ratings could be lowered or withdrawn entirely by a rating agency if, in its judgment, the circumstances warrant. Any negative rating action could adversely affect our ability to access capital at rates and on terms that are attractive. A negative rating action could also adversely impact our business relationships with suppliers and operating partners, who may be less willing to extend credit or offer us similarly favorable terms as secured in the past under such circumstances.

Certain of our subsidiaries have agreements that contain “ratings triggers” that require increased collateral in the form of cash, a letter of credit or other forms of security for new and existing transactions if our credit ratings (including the standalone credit ratings of certain of our subsidiaries) are dropped below investment grade. These agreements are primarily for insurance purposes and for the physical purchase or sale of gas or power. As of December 31, 2024, the collateral requirement that would be required in the event of a downgrade below the ratings trigger levels would amount to approximately $115.5 million. In addition to agreements with ratings triggers, there are other agreements that contain “adequate assurance” or “material adverse change” provisions that could necessitate additional credit support such as letters of credit and cash collateral to transact business.

If our or certain of our subsidiaries’ credit ratings were downgraded, especially below investment grade, financing costs and the principal amount of borrowings would likely increase due to the additional risk of our debt and because certain counterparties may require additional credit support as described above. Such amounts may be material and could adversely affect our cash flows, results of operations and financial condition. Losing investment grade credit ratings may also result in more restrictive covenants and reduced flexibility on repayment terms in debt issuances, lower share price and greater stockholder dilution from common equity issuances, in addition to reputational damage within the investment community.

Adverse economic and market conditions, including increases in inflation or interest rates, recession or changes in investor sentiment could materially and adversely affect our business, results of operations, cash flows, financial condition and liquidity.

Deteriorating, sluggish or volatile economic conditions in our operating jurisdictions could adversely impact our ability to maintain or grow our customer base and collect revenues from customers, which could reduce our revenue or growth rate and increase operating costs. A continued economic downturn or recession, or slowing or stalled recovery from such economic downturn or recession, may have a material adverse effect on our business, financial condition, or results of operations.

We rely on access to the capital markets to finance our liquidity and long-term capital requirements, including expenditures for our utility infrastructure and to comply with future regulatory requirements, to the extent not satisfied by the cash flow generated by our operations. We have historically relied on long-term debt and on the issuance of equity securities to fund a portion of our capital expenditures and repay outstanding debt, and on short-term borrowings to fund a portion of day-to-day business operations. There may be external factors such as inflation, monetary policy or other market conditions which could impact our cost of borrowing and could make it more difficult to obtain financing for our operations or investments on favorable terms. Successful implementation of our long-term business strategies, including capital investment, is dependent upon our ability to access the capital and credit markets, including the banking and commercial paper markets, on competitive terms and rates. An economic downturn or uncertainty, market turmoil, changes in interest rates, changes in tax policy, challenges faced by financial institutions, changes in our credit ratings, or a change in investor sentiment toward us or the utilities industry generally could adversely affect our ability to raise additional capital or refinance debt. For example, because

NiSource Inc.

NIPSCO's current generating facilities substantially rely on coal for its operations, certain financial institutions may choose not to participate in our financing arrangements. In addition, investors may choose to sell or choose not to purchase our stock due to environmental, social and governance or sustainability concerns. Reduced access to capital markets, increased borrowing costs, and/or lower equity valuation levels could reduce future earnings per share and cash flows. In addition, any rise in interest rates may lead to higher borrowing costs, which may adversely impact reported earnings, cost of capital and capital holdings.

We may face limits, or the inability, to access credit and capital markets or may experience significant increases in the cost of capital, which could limit our ability to implement or increase the costs of implementing, our business plan, which, in turn, could materially and adversely affect our results of operations, cash flows, financial condition and liquidity.

Most of our revenues are subject to economic regulation and are exposed to the impact of regulatory rate reviews and proceedings.

Most of our revenues are subject to economic regulation at either the federal or state level. As such, the revenues generated by us are subject to regulatory review by the applicable federal or state authority. These rate reviews determine the rates charged to customers and directly impact revenues. Our financial results are dependent on frequent regulatory proceedings in order to ensure timely recovery of costs and investments. As described in more detail in the risk factor below, the outcomes of these proceedings are uncertain, potentially lengthy and could be influenced by many factors, some of which may be outside of our control, including the cost of providing service, the necessity of expenditures, regulatory interpretations, customer intervention, economic conditions, the political environment and customer affordability. Further, the rate orders are subject to appeal, which creates additional uncertainty as to the rates that will ultimately be allowed to be charged for services.

The actions of regulators and legislators could result in outcomes that may adversely affect our earnings and liquidity.

The rates that our electric and natural gas companies charge their customers are determined by their state regulatory commissions and by the FERC. These state regulatory commissions also regulate the companies' accounting, operations, the issuance of certain securities and certain other matters. The FERC also regulates the transmission of electric energy, the sale of electric energy at wholesale, accounting, issuance of certain securities and certain other matters, including reliability standards through the North American Electric Reliability Corporation (NERC).

Under state and federal law, our electric and natural gas companies are entitled to charge rates that are sufficient to allow them an opportunity to recover their prudently incurred operating and capital costs and a reasonable rate of return on invested capital, to attract needed capital and maintain their financial integrity, while also protecting relevant public interests. Our electric and natural gas companies are required to engage in regulatory approval proceedings as a part of the process of establishing the terms and rates for their respective services. Each of these companies prepares and submits periodic rate filings with their respective regulatory commissions for review and approval, which allows for various entities to challenge our current or future rates, structures or mechanisms and could alter or limit the rates we are allowed to charge our customers. These proceedings typically involve multiple parties, including governmental bodies and officials, consumer advocacy groups, and various consumers of energy, who have differing interests. Any change in rates, including changes in allowed rate of return, are subject to regulatory approval proceedings that can be contentious, lengthy, and subject to appeal. This may lead to uncertainty as to the ultimate result of those proceedings. Established rates are also subject to subsequent prudency reviews by state regulators, whereby various portions of rates could be adjusted, subject to refund or disallowed, including cost recovery mechanisms. The ultimate outcome and timing of regulatory rate proceedings could have a significant effect on our ability to recover costs or earn an adequate return. Adverse decisions in our proceedings could adversely affect our financial position, results of operations and cash flows.

There can be no assurance that regulators will approve the recovery of all operating and capital costs incurred by our electric and natural gas companies, including, but not limited to, costs for construction, operation and maintenance, and compliance with current and future changes in environmental, federal pipeline safety, critical infrastructure and cybersecurity laws and regulations. Further, we face regulatory challenges when our electric and gas companies seek regulatory recovery of increases to materials and other costs as a result of inflationary pressures, including accounting for inflationary pricing in plans and assumptions and ensuring there is a regulatory recovery model. There is debate among state regulators and other stakeholders over how to transition to a decarbonized economy and prudency arguments relative to investing in natural gas assets when the depreciable life of the assets may be shortened due to electrification. The inability to recover a significant amount of operating or capital costs could have an adverse effect on a company's financial position, results of operations and cash flows.

NiSource Inc.

Changes to rates may occur at times different from when costs are incurred. Additionally, catastrophic events at other utilities could result in our regulators and legislators imposing additional requirements that may lead to additional costs or operational requirements for the companies.

In addition to the risk of disallowance of incurred costs, regulators may also impose downward adjustments in a company's allowed ROE as well as assess penalties and fines. Regulators may reduce ROE to mitigate potential customer bill increases due to items unrelated to capital investments. These actions would have an adverse effect on our financial position, results of operations and cash flows.

Our electric business is subject to mandatory reliability and critical infrastructure protection standards established by NERC and enforced by the FERC. The critical infrastructure protection standards focus on controlling access to critical physical and cybersecurity assets. Compliance with the mandatory reliability standards could subject our electric utilities to higher operating costs. In addition, compliance with PHMSA regulations, including the expected final ruling around leak detection and repair requirements could subject our gas utilities to higher operating costs and divert business resources from other activities in order to remain compliant. If our businesses are found to be in noncompliance, we could be subject to sanctions, including substantial monetary penalties, or damage to our reputation.

Changes in tax laws, as well as the potential tax effects of business decisions, could negatively impact our business, results of operations (including our expected project returns from our planned renewable energy projects), financial condition and cash flows.

Our business operations are subject to economic conditions in certain industries.

Business operations throughout our service territories have been and may continue to be adversely affected by economic events at the national and local level where our businesses operate. In particular, sales to large industrial customers, such as those in the steel, oil refining, industrial gas and related industries, are impacted by economic downturns and recession; geographic or technological shifts in production or production methods; and consumer demand for environmentally friendly products and practices. The U.S. manufacturing industry continues to adjust to changing market conditions including international competition, inflation and increasing costs, government and societal pressure to decarbonization, and fluctuating demand for its products.

We are exposed to risk that customers will not remit payment for delivered energy or services, and that suppliers or counterparties will not perform under various financial or operating agreements.

Our extension of credit is governed by a Corporate Credit Risk Management Policy, involves judgment by our employees and is based on an evaluation of customer, supplier, or counterparty's financial condition, credit history and other factors. We monitor our credit risk exposure by obtaining credit reports and updated financial information for customers and suppliers, and by evaluating the financial status of our banking partners and other counterparties by reference to market-based metrics such as credit default swap pricing levels, and to traditional credit ratings provided by the major credit rating agencies. Adverse economic conditions impacting these credit risk exposures could result in an increase in defaults by customers, suppliers and counterparties. We are also exposed to the risk that due to adverse economic conditions one or more suppliers or counterparties may fail or delay the performance of their contractual obligations, such risks could negatively impact our business, financial condition and cash flow.

We are a holding company and are dependent on cash generated by our subsidiaries to meet our debt obligations and pay dividends on our stock.

We are a holding company and conduct our operations primarily through our subsidiaries, which are separate and distinct legal entities. Substantially all of our consolidated assets are held by our subsidiaries. Accordingly, our ability to meet our debt obligations or pay dividends on our common stock and preferred stock is largely dependent upon cash generated by these subsidiaries. In the event a major subsidiary is not able to pay dividends or transfer cash flows to us, our ability to service our debt obligations or pay dividends could be negatively affected.

Capital market performance and other factors may decrease the value of benefit plan assets, which then could require significant additional funding and impact earnings.

The performance of the capital markets affects the value of the assets that are held in trust to satisfy future obligations under defined benefit pension and other postretirement benefit plans. We have significant obligations in these areas and hold significant assets in these trusts. These assets are subject to market fluctuations and may yield uncertain returns, which could fall below our projected rates of return. A decline in the market value of assets may increase the funding requirements of the

obligations under the defined benefit pension plans. Additionally, changes in interest rates affect the liabilities under these benefit plans; as interest rates decrease, the liabilities increase, which could potentially increase funding requirements. Further, the funding requirements of the obligations related to these benefits plans may increase due to changes in governmental regulations and participant demographics, including increased numbers of retirements or longer life expectancy assumptions, as well as voluntary early retirements. In addition, lower asset returns result in increased expenses. Ultimately, significant funding requirements and increased pension or other postretirement benefit plan expenses could negatively impact our results of operations and financial position.

We have significant goodwill. Any future impairments of goodwill could result in a significant charge to earnings in a future period and negatively impact our compliance with certain covenants under financing agreements.

In accordance with GAAP, we test goodwill for impairment at least annually and review our definite-lived intangible assets for impairment when events or changes in circumstances indicate its fair value might be below its carrying value. Goodwill is also tested for impairment when factors, examples of which include reduced cash flow estimates, a sustained decline in stock price or market capitalization below book value, indicate that the carrying value may not be recoverable and results in a significant charge to earnings. We cannot predict the timing, magnitude, or duration of such changes. In general, the carrying value of goodwill would not be recoverable, in which case we may record a non-cash impairment charge, which could materially impact our results of operations and financial position.

A significant impairment charge in the future could impact the capitalization ratio covenant under certain financing agreements. We are subject to a financial covenant under our revolving credit facility, which requires us to maintain a debt to capitalization ratio that does not exceed 70%. As of December 31, 2024, the ratio was 52.6%.

LITIGATION, REGULATORY AND LEGISLATIVE RISKS

The outcome of legal and regulatory proceedings, investigations, inquiries, claims and litigation related to our business operations may have a material adverse effect on our results of operations, financial position or liquidity.

We are, or may be, involved in legal and regulatory proceedings, investigations, inquiries, claims and litigation in connection with our business operations, the most significant of which are summarized in, Note 19, "Other Commitments and Contingencies," in the Notes to Consolidated Financial Statements. While we maintain insurance, it may not cover all costs or expenses incurred relating to litigation. Due to the inherent uncertainty of the outcomes of such matters, there can be no assurance that the resolution of any particular claim or proceeding would not have a material adverse effect on our results of operations, financial position or liquidity.

Our businesses are subject to various federal, state and local laws, regulations, tariffs and policies and a failure to comply with changes in, or new or different interpretations of, such laws, regulations, tariffs and policies could have an adverse impact on our business.

Our businesses are subject to various federal, state and local laws, regulations, tariffs and policies, including, but not limited to, those relating to natural gas pipeline safety, employee safety, the environment and our energy infrastructure. In particular, we are subject to significant federal, state and local regulations applicable to utility companies, including regulations by the various utility commissions in the states where we serve customers. These regulations significantly influence our operating environment, may affect our ability to recover costs from utility customers, and cause us to incur substantial compliance and other costs. Existing laws, regulations, tariffs and policies may be revised or become subject to new interpretations, and new laws, regulations, tariffs and policies may be adopted or become applicable to us and our operations. In some cases, compliance with new or different laws, regulations, tariffs and policies increases our costs or risks of liability. Supply chain constraints, both direct and indirect, including but not limited to material or labor shortages, may challenge our ability to remain in compliance with these laws, regulations, tariffs and policies and operate our business in a compliant manner. If we fail to comply with laws, regulations and tariffs applicable to us or with any changes in or new interpretations of such laws, regulations, tariffs or policies, our financial condition, results of operations, regulatory outcomes and cash flows may be materially adversely affected.

Our businesses are regulated under numerous environmental laws and regulations. The cost of compliance with these laws and regulations, and changes to or additions to, or reinterpretations of the laws and regulations, could be significant, and the cost of compliance may not be recoverable. Liability from the failure to comply with existing or changed laws and regulations could have a material adverse effect on our business, results of operations, cash flows and financial condition.

Our businesses are subject to extensive federal, state and local environmental laws and rules that regulate, among other things, air emissions, water usage and discharges, leak detection and repair, GHG and waste products such as CCR. Compliance with

these legal obligations require us to make significant expenditures for installation of pollution control equipment, remediation, environmental monitoring, emissions fees, and permits at many of our facilities. Furthermore, if we fail to comply with environmental laws and regulations or are found to have caused damage to the environment or persons, that failure or harm may result in the assessment of civil or criminal penalties and damages against us, injunctions to remedy the failure or harm, and the inability to operate facilities as designed and intended. Further, failing to comply with such laws and regulations or a determination that we have caused damage to the environment or persons, could result in reputational damage.

Existing environmental laws and regulations may be revised and new laws and regulations may be adopted or become applicable to us, with an increasing focus on the impact of coal and natural gas facilities that may result in significant additional expense and operating restrictions on our facilities, which may not be fully recoverable from customers and could materially affect the continued economic viability of our facilities.

An area of significant uncertainty and risk are potential changes to the laws concerning emission of GHG. While we have set a Net Zero Goal and continue to execute our plan to reduce our GHG emissions by the increased sourcing of renewable energy, priority pipeline replacement, leak detection and repair, and other methods, GHG emissions are anticipated to be associated with energy delivery for many years. Future GHG legislation and/or regulation related to the generation of electricity or the extraction, production, distribution, transmission, storage and end use of natural gas could materially impact our gas supply, financial position, financial results and cash flows.

Another area of significant uncertainty and risk are the regulations concerning CCR. The EPA has issued regulations and may promulgate additional regulations concerning the management, storage, use and disposal of CCRs. NIPSCO is also incurring or will incur costs associated with closing, corrective action, and ongoing monitoring of certain CCR impoundments. Further, a release of CCR to the environment could result in remediation costs, penalties, claims, litigation, increased compliance costs, and reputational damage.

We currently have a pending application with the EPA to continue operation of a CCR impoundment that is tied to operation of R.M. Schahfer Generating Station Units 17 and 18 to the end of 2025, with the CCR impoundment closing by October 2028. In proposed and final EPA actions denying continued operation of CCR impoundments at other utilities, EPA said that CCR impoundments should cease receipt of CCRs within 135 days of final EPA action unless certain conditions are demonstrated, such as potential reliability issues. In the event that approval is not obtained, future operations could be impacted.

The actual future expenditures to achieve environmental compliance depends on many factors, including the nature and extent of impact, the method of improvement, the cost of raw materials, contractor costs, and requirements established by environmental authorities. Changes or increases in costs and the ability to recover under regulatory mechanisms could affect our financial position, financial results and cash flows.

Changes in tax laws or the interpretation thereof and challenges to tax positions could adversely affect our financial results.

We are subject to taxation by the various taxing authorities at the federal, state and local levels where we do business. Legislation or regulation which could affect our tax burden could be enacted or interpreted by any of these governmental authorities. The IRA imposed a 15 percent minimum tax rate on book earnings for corporations with higher than $1 billion of annual income, along with a 1 percent excise tax on corporate stock repurchases while providing tax incentives to promote various clean energy initiatives. Our NIPSCO subsidiary's renewable portfolio is eligible for tax credits associated with the investment in renewable generation assets and production of power from those assets. Statutory changes, a challenge by a taxing authority, changes in taxing authorities' administrative interpretations, decisions, policies and positions, our ability to utilize tax benefits such as carryforwards or tax credits, or a deviation from other tax-related assumptions may cause actual financial results to deviate from previous estimates.

ITEM 1B. UNRESOLVED STAFF COMMENTS

NISOURCE INC.

None.

ITEM 1C. CYBERSECURITY

NiSource has implemented and maintains a comprehensive cybersecurity program that includes a variety of security controls and measures designed to identify, assess, and manage material cybersecurity risks. The program is a part of NiSource's enterprise risk management strategy. The enterprise risk team and the Risk Management Committee review material risks to any NiSource operating company based on perspectives from external experts, peer surveys, and the potential impact to NiSource's enterprise assets and strategic objectives.

Risk events are classified based on both the timing of impact and NiSource's ability to preventatively mitigate the risk. For the cybersecurity risks that can be preventively mitigated, the enterprise risk team gathers quarterly updates on mitigation gap closure from risk owners. The Risk Management Committee reviews any mitigation gaps identified by risk owners and approves or rejects the pace of mitigation activities as a statement of risk tolerance and then directs that mitigation activities be included in budgets and the business plan as appropriate.

The NiSource cybersecurity program includes the following key components:

Risk assessment. NiSource regularly assesses its cybersecurity risks to identify and prioritize the most significant threats. The risk assessment process considers a variety of factors, including those specific to the utility/energy industry, the types of data NiSource collects and stores, and the threats posed by known vulnerabilities. NiSource engages third parties to perform independent assessments of its cybersecurity program, provide intelligence about the threat environment, and to provide operational assistance in managing the program. Annually, a third-party independent assessment is performed to evaluate NiSource cybersecurity maturity against a framework of cybersecurity controls. NiSource also performs bi-annual penetration testing and social engineering assessments performed by a third-party.

Third-party risk management. NiSource performs cyber assessments periodically on third-party vendors and service providers with whom NiSource shares data, relies on for critical business functions, or provides access to the NiSource network or systems. NiSource's Supply Chain function works with the Legal and Cyber functions to periodically update cybersecurity contractual provisions in its vendor agreements, with deviations from such provisions requiring approval from the Legal and Cyber functions. NiSource's Supplier Code of Business Conduct requires, among other things, that suppliers ensure safe and secure use of information assets, comply with applicable law relating to personal information, and adhering to standards relative to the use and protection of Company information, including that of our employees, customers, vendors and other stakeholders. In addition, all vendors and contractors that have access and/or connectivity to the NiSource environment must complete cybersecurity training annually.

Security controls. NiSource has implemented a variety of security controls to mitigate cybersecurity risks. These controls include technical controls, such as firewalls and intrusion detection systems, as well as administrative controls, such as employee training and security awareness programs. To ensure cybersecurity controls, NiSource OT within the electric business adheres to the NERC CIP. Within the natural gas business, cybersecurity controls are managed and monitored based on the TSA Security Directives.

Incident response. NiSource has a comprehensive incident response plan in place to respond to cybersecurity incidents. The plan includes steps for detection, analysis, containment, eradication, and recovery from incidents, as well as steps for notifying affected individuals and regulators.

The NiSource Board of Directors' Audit Committee has responsibility for oversight of the cybersecurity program and risks from cybersecurity threats. The Audit Committee regularly reviews NiSource's cybersecurity posture. The CISO briefs the Audit Committee on cybersecurity risks and risk mitigation initiatives and actions. In addition, the Board of Directors remains informed of key and emerging cybersecurity risks and receives updates by the Audit Committee after each of its regularly scheduled meetings.

At the management level, the CISO leads the cybersecurity program and is responsible for assessing and managing cybersecurity risks. Our CISO has expertise and experience in cybersecurity derived from over 15 years of cyber related work experience and possesses several certifications including CISSP, CRISC, and CISA. The CISO is supported by the NiSource

Enterprise Security team which performs the cybersecurity function and engages directly on the prevention, detection, mitigation, and remediation of cybersecurity incidents.

As of the date of filing this Annual Report on Form 10-K, NiSource is not aware of any material cybersecurity incidents during the past year. NiSource monitors the increasing sophistication of cybersecurity threats and continues to allocate resources to enhance its cybersecurity program to protect its information systems and assets. No cybersecurity program is effective to identify and mitigate all threats and NiSource cannot guarantee that it will be able to prevent all cybersecurity incidents. Such an incident could interrupt our normal operations and require us to incur significant costs to remediate any such incident and could have a material impact on our businesses, operations and financial condition. For more information regarding the risks associated with cybersecurity, refer to “Item 1A. Risk Factors” of this Annual Report on Form 10-K.

ITEM 2. PROPERTIES

Discussed below are the principal properties held by us and our subsidiaries as of December 31, 2024.

Columbia Operations
Refer to Item 1, "Business - Columbia Operations," of this report for further information on Columbia Operations properties.

NIPSCO Operations
Refer to Item 1, "Business - NIPSCO Operations," of this report for further information on NIPSCO Operations properties.

Corporate and Other Operations
We own the Southlake Complex, our 325,000 square foot headquarters building located in Merrillville, Indiana.

Character of Ownership
Our principal properties and our subsidiaries' principal properties are owned free from encumbrances, subject to minor exceptions, none of which are of such a nature as to impair substantially the usefulness of such properties. Many of our subsidiary offices in various communities served are occupied under leases. All properties are subject to routine liens for taxes, assessments and undetermined charges (if any) incidental to construction. It is our practice to regularly pay such amounts, as and when due, unless contested in good faith. In general, the electric lines, gas pipelines and related facilities are located on land not owned by us or our subsidiaries, but are covered by necessary consents of various governmental authorities or by appropriate rights obtained from owners of private property. We do not, however, generally have specific easements from the owners of the property adjacent to public highways over, upon or under which our electric lines and gas distribution pipelines are located. At the time each of the principal properties was purchased, a title search was made. In general, no examination of titles as to rights-of-way for electric lines, gas pipelines or related facilities was made, other than examination, in certain cases, to verify the grantors’ ownership and the lien status thereof.

ITEM 3. LEGAL PROCEEDINGS

For a description of our legal proceedings, see Note 19, "Other Commitments and Contingencies - C. Legal Proceedings," in the Notes to Consolidated Financial Statements.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

NISOURCE INC.

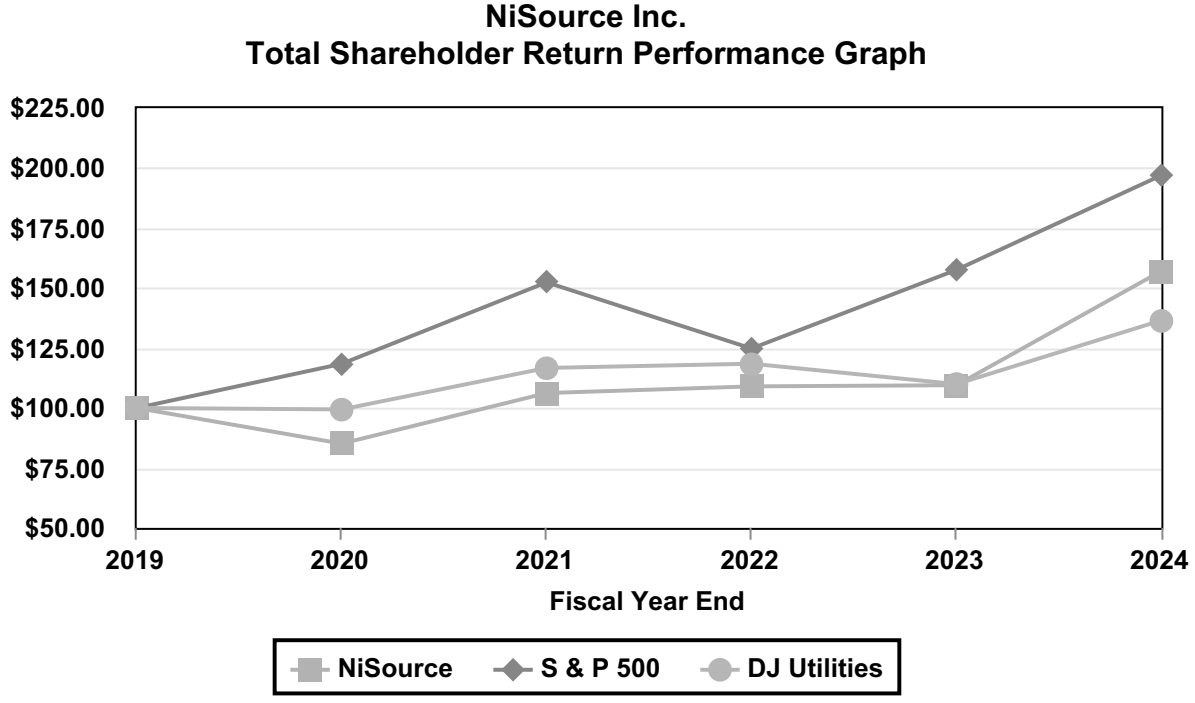
NiSource's common stock is listed and traded on the New York Stock Exchange under the symbol "NI."

Holders of shares of NiSource's common stock are entitled to receive dividends if and when declared by the Board out of funds legally available. There is no preferred stock outstanding as of December 31, 2024. The policy of the Board has been to declare cash dividends on a quarterly basis payable on or about the 20th day of February, May, August, and November. At its January 23, 2025 meeting, the Board declared a quarterly common dividend of $0.280 per share, payable on February 20, 2025 to holders of record on February 3, 2025.

Although the Board currently intends to continue the payment of regular quarterly cash dividends on common shares, the timing and amount of future dividends will depend on the earnings of NiSource's subsidiaries, their financial condition, cash requirements, regulatory restrictions, any restrictions in financing agreements and other factors deemed relevant by the Board. There can be no assurance that NiSource will continue to pay such dividends or the amount of such dividends.

As of February 5, 2025 NiSource had 14,161 common stockholders of record and 469,939,639 shares outstanding.

The graph below compares the cumulative total shareholder return of NiSource's common stock for the period commencing December 31, 2019 and ending December 31, 2024 with the cumulative total return for the same period of the S&P 500 and the Dow Jones Utility indices.



The foregoing performance graph is being furnished as part of this Annual Report on Form 10-K solely in accordance with the requirement under Rule 14a-3(b)(9) to furnish stockholders with such information, and therefore, shall not be deemed to be filed or incorporated by reference into any filings by NiSource under the Securities Act or the Exchange Act.

The total shareholder return for NiSource common stock and the two indices is calculated from an assumed initial investment of $100 and assumes dividend reinvestment.

Purchases of Equity Securities by Issuer and Affiliated Purchasers. For the three months ended December 31, 2024, no equity securities that are registered by NiSource Inc. pursuant to Section 12 of the Securities Exchange Act of 1934 were purchased by or on behalf of us or any of our affiliated purchasers.

ITEM 6. RESERVED

NiSource Inc.
Not applicable.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

NISOURCE INC.

Index	Page
Executive Summary	35
Summary of Consolidated Financial Results	38
Results and Discussion of Operations	39
Columbia Operations	40
NIPSCO Operations	43
Liquidity and Capital Resources	48
Market Risk Disclosures	52
Other Information	53

EXECUTIVE SUMMARY

This Management's Discussion and Analysis of Financial Condition and Results of Operations ("Management's Discussion") includes management's analysis of past financial results and certain potential factors that may affect future results, potential future risks and approaches that may be used to manage those risks. See "Note regarding forward-looking statements" and Item 1A, "Risk Factors" at the beginning of this report for a list of factors that may cause results to differ materially. Refer to the "Business" section under Item 1 of this Annual Report on Form 10-K and Note 21, "Business Segment Information," in the Notes to Consolidated Financial Statements for further discussion of our regulated utility business segments.

This Management's Discussion is designed to provide an understanding of our operations and financial performance and should be read in conjunction with our Consolidated Financial Statements and related Notes to Consolidated Financial Statements in this Annual Report on Form 10-K.

We are an energy holding company under the Public Utility Holding Company Act of 2005 whose subsidiaries are fully regulated natural gas and electric utility companies serving customers in six states. We generate substantially all of our operating income through these rate-regulated businesses, which are summarized for financial reporting purposes into two primary reportable segments: Columbia Operations and NIPSCO Operations.

Our vision is to be a premier, innovative and trusted energy partner. We exist to deliver safe, reliable energy that drives value to our customers. In order to achieve this goal, we seek to develop strategies that benefit all stakeholders as we (i) support long-term infrastructure investment and safety programs to better serve our customers, (ii) align our tariff structures with our cost structure, and (iii) drive value and enable growth in an evolving energy ecosystem. These strategies focus on improving safety and reliability, enhancing customer experience, pursuing regulatory and legislative initiatives to increase accessibility for customers currently not on our gas and electric service, ensuring customer affordability and reducing emissions while generating sustainable returns. The safety of our customers, communities and employees remains our focus. Serving as a guiding practice for our SMS, NiSource is certified in conformance to the American Petroleum Institute Recommended Practice 1173, which is the foundation to our journey towards operational excellence.

2024 Overview: In 2024, we continued to make significant progress on the remaining portfolio of projects that will enable our electric generation transition, including placing one solar and battery project into service and receiving approval of a new gas peaking facility. During the year, we received orders for three rate cases: Columbia of Pennsylvania, Columbia of Kentucky, and NIPSCO Gas. In addition, the Columbia of Virginia, Columbia of Maryland and NIPSCO Electric rate cases filed in 2024 are anticipated to be resolved during 2025 with balanced outcomes supporting all stakeholders. We continued to build and advance our SMS by successfully maintaining our certification of conformance for API 1173 and achieving LRQA's ISO 50001 certification. Between our Columbia and NIPSCO Operating Segments, we added 21,000 customers. We also invested $1.5 billion in infrastructure modernization to enhance safe, reliable service, including replacement of 288 miles of distribution main and service lines, 24 miles of underground cable and 1,240 electric poles. We achieved the first major milestone in our Transformation road map and continue to increase the efficiency of our operating companies.

The following describes in more detail the advancements we have made in our key strategic initiatives.

Energy Transition: We are advancing our energy transition strategy primarily through the continuation and enhancement of existing programs, such as retiring and replacing remaining coal-fired electric generation by 2028 with a balanced mix of low or zero-emission electric generation and battery storage, ongoing pipe replacement and modernization programs, and deployment of advanced leak detection and repair. Our electric generation transition, initiated through our 2018 Integrated Resource Plan

NiSource Inc.

("2018 Plan") is well underway, and we are continually adjusting to the dynamic energy landscape. As of December 31, we have placed in service owned renewable and storage projects, developed under BTAs, with combined nameplate capacities of 1,065 MW and 45 MW respectively. Renewable PPA projects with a combined nameplate capacity of 600 MW have also been placed in service. In addition, renewable and storage BTA projects with combined nameplate capacities of 1,085 MW and 56 MW, respectively, and renewable PPA projects with a combined nameplate capacity of 600 MW were under development as of December 31, all of which have received IURC approval. The capacity figure for BTA projects in development includes the Templeton Wind project. In October 2024, NIPSCO contracted with a developer to convert the previously approved Templeton Wind PPA to a BTA and has provided a notice of intent to file a CPCN with the IURC. In 2024, the IURC approved full ownership of the Cavalry, Dunns Bridge II, Fairbanks and Gibson and the cost of the Fairbanks project as contemplated in contractual actions. Full ownership of these projects allows NIPSCO to leverage provisions of the IRA, monetize renewable tax credits more effectively, and provide enhanced benefits to customers as compared to the previous tax equity partnership structure approved by the IURC. We remain on track to retire R.M Schahfer's remaining two coal units by the end of 2025. For additional information, see "Results and Discussion of Operations - NIPSCO Operations," in this Management's Discussion.

NIPSCO's 2021 Integrated Resource Plan ("2021 Plan") lays out a timeline to retire the Michigan City Generating Station by the end of 2028. The 2021 Plan calls replacing the retiring coal units with a diverse portfolio of resources including demand side management resources, renewables, stand-alone energy storage and upgrades to existing facilities at the Sugar Creek Generating Station, among other steps. In 2024, Sugar Creek completed an Advanced Gas Path Tech upgrade that will enhance its overall production capabilities. Additionally, the 2021 Plan calls for a new natural gas peaking facility to replace existing vintage gas peaking facilities at the R.M. Schahfer Generating Station to support system reliability and resiliency, and upgrades to the electric transmission system. In October 2024, we received approval for the issuance of a CPCN for an approximately 400 MW natural gas peaking generation facility from the IURC. The planned retirement of the two vintage gas peaking facilities at the R.M. Schahfer Generating Station is also expected to occur by the end of 2028. Final retirement dates for these units, as well as Michigan City, will be subject to MISO approval.

NIPSCO's 2024 Plan was submitted to the IURC on December 9, 2024. The 2024 Plan informs future generation investments required to ensure reliability for NIPSCO's customers and incorporates factors such as anticipated load growth from data centers and other economic development opportunities, new EPA emissions rules, and evolving MISO resource accreditation rules. We have seen an acceleration of customer interest in our northern Indiana service territory in the form of data center development. We believe data center development can enhance our local tax base, diversify the employment base across the state of Indiana, and provide greater value to existing customers and shareholders. We are evaluating the potential for data center development in our service territory, including ways to effectively manage the potential power demand, generation sources, and transmission capabilities to meet potential load growth from any data center customer, while at the same time focusing on our environmental goals. We expect the management of large load growth would require new generation resources, including gas-fired resource, and transmission capabilities.We plan to move as efficiently as possible while maintaining the integrity of our commercial, planning, regulatory, procurement and operational execution processes.

We continue to enhance safety and reduce methane emissions on our gas systems through modernization programs and utilization of advanced leak detection and repair. In addition, we plan to advance other low- or zero-emission energy resources and technologies, such as hydrogen and renewable natural gas.

Transformation: Our enterprise-wide transformation roadmap focuses on operational excellence, safety, operation and maintenance management, and unlocking efficiencies. We are committed to identifying and implementing initiatives that will enable us to streamline work and improve processes company-wide. These efforts include investments in proven technologies backed with standardized processes that will change the way we plan, schedule, and execute work in the field and how we engage and provide service to our customers. Taken together, all of our optimization initiatives will prioritize safety and continue to optimize our long-term growth profile. We are making progress towards our transformation goals with a successful completion of the first phase of our WAM program, an enterprise resource planning system that will optimize the scheduling, dispatch, and execution of our field operations. This phase of the program implemented the solution within our electric distribution and transmission operations, while the remaining phases associated with gas distribution and generation operations are anticipated to be completed by the end of 2025.

Economic Environment: We continue to monitor risks related to order and delivery lead times for construction and other materials, potential unavailability of materials due to global shortages in raw materials, and decreased construction labor productivity in the event of disruptions in the availability of materials. We continue to see increasing prices associated with certain materials and supplies. To the extent that work plan delays occur or our costs increase, our business operations, results

of operations, cash flows, and financial condition could be materially adversely affected. Refer to Item 1A. Risk Factors, "Financial, Economic and Market Risks" of this Annual Report on Form 10-K for further detail.

We are faced with increased competition for employee and contractor talent in the current labor market which has resulted in increased costs to attract and retain talent. We are ensuring that we use all internal human capital programs (development, leadership enablement programs, succession, performance management) to promote retention of our current employees along with having a competitive and attractive appeal for potential recruits. With a focus on workforce planning, we are evaluating our future talent footprint by creating flexible work arrangements where possible to support a broader talent footprint for sourcing needed talent. Refer to Item 1A. Risk Factors, "Operational Risks" of this Annual Report on Form 10-K for further detail.

The market price of natural gas was stable during 2024 and was very close to levels seen in 2023. Similar to natural gas pricing, electric commodity costs have remained stable due to available supplies of natural gas and coal and the growing influence of renewable generation on power market pricing. Changes in commodity prices do not have a material impact on our results of operations, however higher commodity prices can impact our cash flows and liquidity. For more information on our commodity price impacts, see Item 1A. Risk Factors, "Operational Risks" of this Annual Report on Form 10-K, "Results and Discussion of Segment Operations - Columbia Operations," "Results and Discussion of Segment Operations - NIPSCO Operations," and "Market Risk Disclosures."

We continue to evaluate our financing plan to manage interest expense and exposure to rates. For more information on interest rate risk, see "Market Risk Disclosures" and Item 1A. Risk Factors, "Financial, Economic and Market Risks" of this Annual Report on Form 10-K.

NIPSCO Minority Interest Transaction: On December 31, 2023, contemporaneously with the closing of the NIPSCO Minority Interest Transaction, Blackstone, NIPSCO Holdings I, NIPSCO Holdings II, and NiSource entered into an Amended and Restated Limited Liability Company Agreement (the "LLC Agreement") of NIPSCO Holdings II. On January 31, 2024, BIP transferred a 4.5% equity interest in NIPSCO Holdings II to BIP Blue Buyer VCOC L.L.C., a Delaware limited liability company and also an affiliate of Blackstone. Effective upon the closing of this transfer, the members of NIPSCO Holdings II entered into a Second Amended and Restated Limited Liability Company Operating Agreement of NIPSCO Holdings II (the "Amended LLC Agreement"). The two affiliates of Blackstone must vote their equity holdings under the Amended LLC Agreement as one investor. Refer to Note 4, "Noncontrolling Interests," in the Notes to the Consolidated Financial Statements for more information on this transaction.

NISOURCE INC.

Summary of Consolidated Financial Results

A summary of our consolidated financial results for the years ended December 31, 2024, 2023 and 2022, are presented below:

Year Ended December 31, *(in millions, except per share amounts)*	**2024**	2023	2022	Favorable (Unfavorable) 2024 vs. 2023	Favorable (Unfavorable) 2023 vs. 2022
Operating Revenues	**$ 5,455.1**	$ 5,505.4	$ 5,850.6	$ (50.3)	$ (345.2)
Operating Expenses					
Cost of energy	**1,132.2**	1,533.3	2,110.5	401.1	577.2
Other Operating Expenses	**2,867.4**	2,676.6	2,474.3	(190.8)	(202.3)
Total Operating Expenses	**3,999.6**	4,209.9	4,584.8	210.3	374.9
Operating Income	**1,455.5**	1,295.5	1,265.8	160.0	29.7
Total Other Deductions, Net	**(452.7)**	(481.6)	(309.4)	28.9	(172.2)
Income Taxes	**158.1**	139.5	164.6	(18.6)	25.1
Net Income	**844.7**	674.4	791.8	170.3	(117.4)
Net (loss) income attributable to noncontrolling interest	**84.3**	(39.9)	(12.3)	(124.2)	27.6
Net Income attributable to NiSource	**760.4**	714.3	804.1	46.1	(89.8)
Preferred dividends and redemption premium	**(20.7)**	(52.6)	(55.1)	31.9	2.5
Net Income Available to Common Shareholders	**739.7**	661.7	749.0	78.0	(87.3)
Basic Earnings Per Share	**$ 1.63**	$ 1.59	$ 1.84	$ 0.04	$ (0.25)
Diluted Earnings Per Share	**$ 1.62**	$ 1.48	$ 1.70	$ 0.14	$ (0.22)

The majority of the costs of energy in both segments are tracked costs that are passed through directly to the customer, resulting in an equal and offsetting amount reflected in operating revenues.

The increase in net income available to common shareholders during 2024 was primarily due to higher revenues, net of cost of energy, driven by our continued investment in safety, reliability and low- or zero-emission generation as well as increased AFUDC, reported in Other Deductions, Net, primarily related to NIPSCO's wholly owned Cavalry and Dunns Bridge II projects. The increase in net income available to common shareholders is partially offset by higher depreciation expense attributed to our planned capital expenditures, higher interest expense and higher net income attributable to noncontrolling interest following the consummation of the NIPSCO Minority Interest Transaction. See Note 6, "Equity," for additional information.

For additional information on operating income variance drivers see "Results and Discussion of Operations" for Columbia Operations and NIPSCO Operations in this Management's Discussion.

Other Deductions, Net

The change in Other deductions, net in 2024 compared to 2023 is primarily driven by higher long-term debt interest in 2024 offset by increases in AFUDC. See Note 7, "Short-Term Borrowings,"and Note 8, "Long-Term Debt," in the Notes to Consolidated Financial Statements for additional information.

Income Taxes

The increase in income tax expense in 2024 compared to the same period in 2023 is primarily due to higher pre-tax income, partially offset by the tax effect of non-controlling interest. Refer to Note 15, "Income Taxes," in the Notes to Consolidated Financial Statements for additional information on income taxes and the change in the effective tax rate.

NISOURCE INC.

RESULTS AND DISCUSSION OF OPERATIONS

Presentation of Segment Information

In response to the NIPSCO Minority Interest Transaction, our operations are now evaluated through two primary reportable segments, Columbia Operations and NIPSCO Operations. Our historical segment disclosures have been recast to be consistent with the current presentation. Columbia Operations aggregates the results of the fully regulated and wholly owned subsidiaries of NiSource Gas Distribution Group, Inc. Each Columbia distribution company is an operating segment which we aggregate to form the Columbia Operations reportable segment. NIPSCO Operations aggregates the results of NIPSCO Holdings I, and its majority-owned subsidiaries, including NIPSCO, which has both fully regulated gas and electric operations in northern Indiana. The remainder of our operations, which are not significant enough on a stand-alone basis to warrant treatment as a reportable segment, are presented as "Corporate and Other" within the Notes to the Consolidated Financial Statements and primarily are comprised of interest expense on holding company debt, and unallocated corporate costs and activities.

NiSource Inc.
Columbia Operations

Financial and operational data for the Columbia Operations segment for the years ended December 31, 2024, 2023 and 2022, are presented below:

				Favorable (Unfavorable)	
Year Ended December 31, *(in millions)*	**2024**	2023	2022	2024 vs. 2023	2023 vs. 2022
Operating Revenues	**$ 2,716.0**	$ 2,746.1	$ 2,964.4	$ (30.1)	$ (218.3)
Operating Expenses					
Cost of energy	**514.7**	645.0	978.4	130.3	333.4
Operation and maintenance	**837.5**	792.3	791.3	(45.2)	(1.0)
Depreciation and amortization	**409.1**	371.7	329.4	(37.4)	(42.3)
Loss on impairment of assets	**2.7**	—	—	(2.7)	—
Loss (gain) on sale of assets, net	**4.7**	—	(103.9)	(4.7)	(103.9)
Other taxes	**218.6**	198.8	184.2	(19.8)	(14.6)
Total Operating Expenses	**1,987.3**	2,007.8	2,179.4	20.5	171.6
Operating Income	**$ 728.7**	$ 738.3	$ 785.0	$ (9.6)	$ (46.7)
Revenues					
Residential	**$ 1,891.5**	$ 1,882.8	$ 1,918.1	$ 8.7	$ (35.3)
Commercial	**588.4**	606.2	674.8	(17.8)	(68.6)
Industrial	**145.2**	139.5	136.4	5.7	3.1
Off-System	**42.6**	60.7	192.8	(18.1)	(132.1)
Other	**48.3**	56.9	42.3	(8.6)	14.6
Total	**$ 2,716.0**	$ 2,746.1	$ 2,964.4	$ (30.1)	$ (218.3)
Sales and Transportation (MMDth)					
Residential	**153.2**	155.2	180.2	(2.0)	(25.0)
Commercial	**121.8**	120.4	134.3	1.4	(13.9)
Industrial	**277.9**	255.3	243.2	22.6	12.1
Off-System	**23.8**	31.8	32.3	(8.0)	(0.5)
Other	**0.2**	0.3	0.3	(0.1)	—
Total	**576.9**	563.0	590.3	13.9	(27.3)
Heating Degree Days	**4,262**	4,373	5,195	(111)	(822)
Normal Heating Degree Days	**5,134**	5,137	5,137	(3)	—
% (Warmer) Colder than Normal	**(17)%**	(15)%	1 %		
% (Warmer) Colder than Prior Year	**(3)%**	(16)%	8 %		
Gas Distribution Customers					
Residential	**2,225,564**	2,215,293	2,201,999	10,271	13,294
Commercial	**188,699**	188,561	188,374	138	187
Industrial	**1,991**	1,986	1,995	5	(9)
Other	**5**	4	3	1	1
Total	**2,416,259**	2,405,844	2,392,371	10,415	13,473

NiSource Inc.
Columbia Operations (continued)

Comparability of operation and maintenance expenses, depreciation and amortization, and other taxes may be impacted by regulatory, depreciation and tax trackers that allow for the recovery in rates of certain costs.

The underlying reasons for changes in our operating revenues and expenses from 2024 to 2023 are presented in the respective tables below.

	Favorable (Unfavorable)
Changes in Operating Revenues *(in millions)*	**2024 vs 2023**
New rates from base rate proceedings and regulatory capital programs	$ 112.5
The effects of customer growth	6.2
The effects of customer usage	5.9
The effects of weather in 2024 compared to 2023	(5.2)
Other	(4.2)
Change in operating revenues (before cost of energy and other tracked items)	$ 115.2
Operating revenues offset in operating expense	
Lower cost of energy billed to customers	(130.3)
Lower tracker recoveries within operation and maintenance, depreciation, and tax	(15.0)
Total change in operating revenues	**$ (30.1)**

Weather
In general, we calculate the weather-related revenue variance based on changing customer demand driven by weather variance from normal heating degree days, net of weather normalization mechanisms. Our composite heating degree days reported do not directly correlate to the weather-related dollar impact on the results of Columbia Operations. Heating degree days experienced during different times of the year or in different operating locations may have more or less impact on volume and dollars depending on when and where they occur. When the detailed results are combined for reporting, there may be weather-related dollar impacts on operations when there is not an apparent or significant change in our aggregated composite heating degree day comparison.

Throughput
The increase in total volumes sold and transported in 2024 compared to 2023 of 13.9 MMDth is primarily attributable to the increased industrial usage offset by off-system sales.

NiSource Inc.
Columbia Operations (continued)

Commodity Price Impact

Cost of energy for the Columbia Operations segment is principally comprised of the cost of natural gas procured on behalf of and sold to customers while providing transportation and distribution services. All of our Columbia Operations companies have state-approved recovery mechanisms that provide a means for full recovery of prudently incurred gas costs. These are tracked costs that are passed through directly to the customer, and the gas costs included in revenues are matched with the gas cost expense recorded in the period. Any difference in actual costs incurred and amounts billed to customers is recorded on the Consolidated Balance Sheets as under-recovered or over-recovered gas cost to be included in future customer billings. Therefore, increases in these tracked operating expenses are offset by increases in operating revenues and have essentially no impact on net income. Certain Columbia Operations companies continue to offer choice opportunities, where customers can choose to purchase gas from a third-party supplier, through regulatory initiatives in their respective jurisdictions.

		Favorable (Unfavorable)
Changes in Operating Expenses *(in millions)*		**2024 vs 2023**
Higher employee related expenses	$	(47.5)
Higher depreciation and amortization expense		(37.4)
Higher property tax		(17.2)
Loss on sale of assets and impairments		(7.4)
Higher materials and supplies expense		(7.0)
Other		(8.3)
Change in operating expenses (before cost of energy and other tracked items)	$	(124.8)
Operating expenses offset in operating revenue		
Lower cost of energy billed to customers		130.3
Higher tracker recoveries within operation and maintenance, depreciation, and tax		15.0
Total change in operating expense	**$**	**20.5**

NiSource Inc.
NIPSCO Operations

Financial and operational data for the NIPSCO Operations segment, which services both gas and electric customers, for the years ended December 31, 2024, 2023 and 2022, are presented below:

				Favorable (Unfavorable)	
Year Ended December 31, *(in millions)*	**2024**	2023	2022	2024 vs. 2023	2023 vs. 2022
NIPSCO Operations					
Operating Revenues	**$ 2,752.0**	$ 2,771.6	$ 2,887.1	$ (19.6)	$ (115.5)
Operating Expenses					
Cost of energy	**617.5**	888.3	1,132.1	270.8	243.8
Operation and maintenance	**761.4**	787.7	740.4	26.3	(47.3)
Depreciation and amortization	**590.3**	493.8	449.4	(96.5)	(44.4)
Loss on impairment of assets	**0.4**	—	—	(0.4)	—
Loss (gain) on sale of assets, net	**(1.7)**	2.2	—	3.9	(2.2)
Other taxes	**64.3**	57.9	72.1	(6.4)	14.2
Total Operating Expenses	**2,032.2**	2,229.9	2,394.0	197.7	164.1
Operating Income	**$ 719.8**	$ 541.7	$ 493.1	$ 178.1	$ 48.6

				Favorable (Unfavorable)	
Year Ended December 31, *(in millions)*	**2024**	2023	2022	2024 vs. 2023	2023 vs. 2022
NIPSCO Electric					
Revenues					
Residential	**$ 649.9**	$ 583.9	$ 592.4	$ 66.0	$ (8.5)
Commercial	**620.4**	578.1	571.0	42.3	7.1
Industrial	**500.0**	475.0	561.4	25.0	(86.4)
Wholesale	**38.3**	32.0	13.5	6.3	18.5
Other	**105.0**	116.0	93.4	(11.0)	22.6
Total	**$ 1,913.6**	$ 1,785.0	$ 1,831.7	$ 128.6	$ (46.7)
Sales (GWh)					
Residential	**3,404.9**	3,262.9	3,482.9	142.0	(220.0)
Commercial	**3,697.9**	3,614.2	3,682.4	83.7	(68.2)
Industrial	**7,984.8**	7,820.3	7,915.3	164.5	(95.0)
Wholesale	**889.7**	556.4	50.0	333.3	506.4
Other	**85.2**	78.9	89.5	6.3	(10.6)
Total	**16,062.5**	15,332.7	15,220.1	729.8	112.6
Cooling Degree Days	**903**	710	942	193	(232)
Normal Cooling Degree Days	**852**	831	831	21	—
% Warmer (Colder) than Normal	**6 %**	(15)%	13 %		
% Warmer (Colder) than prior year	**27 %**	(25)%	(8)%		
NIPSCO Electric Customers					
Residential	**430,648**	427,217	424,735	3,431	2,482
Commercial	**59,214**	58,779	58,374	435	405
Industrial	**2,121**	2,126	2,130	(5)	(4)
Wholesale	**705**	708	710	(3)	(2)
Other	**2**	3	3	(1)	—
Total	**492,690**	488,833	485,952	3,857	2,881

NiSource Inc.
NIPSCO Operations

				Favorable (Unfavorable)	
Year Ended December 31, (in millions)	**2024**	2023	2022	2024 vs. 2023	2023 vs. 2022
NIPSCO Gas					
Revenues					
Residential	**$ 540.9**	$ 634.9	$ 691.5	$ (94.0)	$ (56.6)
Commercial	**202.4**	249.1	267.6	(46.7)	(18.5)
Industrial	**79.0**	86.9	85.1	(7.9)	1.8
Other	**16.1**	15.7	11.2	0.4	4.5
Total	**$ 838.4**	$ 986.6	$ 1,055.4	$ (148.2)	$ (68.8)
Sales and Transportation Volumes (MMDth)					
Residential	**58.2**	60.3	68.8	(2.1)	(8.5)
Commercial	**42.5**	43.9	47.0	(1.4)	(3.1)
Industrial	**256.8**	261.8	247.5	(5.0)	14.3
Total	**357.5**	366.0	363.3	(8.5)	2.7
Heating Degree Days	**4,975**	5,198	6,133	(223)	(935)
Normal Heating Degree Days	**6,001**	5,954	5,985	47	(31)
% (Warmer) Colder than Normal	**(17)%**	(13)%	2 %		
% (Warmer) Colder than prior year	**(4)%**	(15)%	10 %		
NIPSCO Gas Customers					
Residential	**801,740**	795,656	789,914	6,084	5,742
Commercial	**66,633**	66,305	66,062	328	243
Industrial	**2,734**	2,808	2,875	(74)	(67)
Total	**871,107**	864,769	858,851	6,338	5,918

NiSource Inc.
NIPSCO Operations (continued)

Comparability of operation and maintenance expenses and depreciation and amortization may be impacted by regulatory and depreciation trackers that allow for the recovery in rates of certain costs.

The underlying reasons for changes in our operating revenues and expenses from 2024 to 2023 are presented in the respective tables below.

	Favorable (Unfavorable)
Changes in Operating Revenues *(in millions)*	**2024 vs 2023**
New rates from base rate proceedings, regulatory capital, and DSM programs	$ 238.4
Renewable Joint Venture revenue, fully offset by Joint Venture operating expense and noncontrolling interest net income (loss)	17.5
The effects of customer usage	11.9
The effects of customer growth	11.2
Decreased fuel handling costs	9.7
Other	(6.2)
Change in operating revenues (before cost of energy and other tracked items)	$ 282.5
Operating revenues offset in operating expense	
Lower cost of energy billed to customers	(270.8)
Lower tracker deferrals within operation and maintenance, depreciation and tax	(32.4)
Reduction in gross receipts tax, offset in operating expenses	1.1
Total change in operating revenues	**$ (19.6)**

Weather
The results of operations for the NIPSCO Operations segment include income from both electric and gas service lines. In general, we calculate the weather-related revenue variance based on changing customer demand driven by weather variance from normal cooling degree days and normal heating degree days, net of weather normalization mechanisms. Our composite cooling and heating degree days reported do not directly correlate to the weather-related dollar impact on the results of NIPSCO Operations. Cooling and heating degree days experienced during different times of the year or in different operating locations may have more or less impact on volume and dollars depending on when they occur. When the detailed results are combined for reporting, there may be weather-related dollar impacts on operations when there is not an apparent or significant change in our aggregated composite cooling and heating degree day comparison.

Sales
The increase in total volumes sold to electric customers for twelve months ended December 31, 2024 compared to the same period in 2023 was primarily attributable to increased usage by wholesale, industrial, and residential customers. NIPSCO Electric results remains closely linked to the performance of the steel industry. MWh sales to steel-related industries accounted for approximately 49.4% and 49.6% of the total industrial MWh sales for the years ended December 31, 2024 and 2023, respectively.

The decrease in total volumes sold to gas customers for the twelve months ended December 31, 2024 compared to the same period in 2023 was primarily attributable to decreased usage by industrial customers.

Commodity Price Impact
Cost of energy for the NIPSCO Operations segment's electric activities is principally comprised of the cost of coal, natural gas purchased for internal generation of electricity, transportation of coal and natural gas, and the cost of power purchased from generators of electricity for its generation an d transmission activities. For its gas distribution activities, NIPSCO Operations' cost of energy is principally comprised of the cost of natural gas procured on behalf of and sold to customers while providing transportation and distribution services. NIPSCO Operations has a state-approved recovery mechanism that provides a means for full recovery of prudently incurred costs of energy. The majority of these costs of energy are passed through directly to the customer, and the costs of energy included in operating revenues are matched with the cost of energy expense recorded in the period. Any difference in actual costs incurred and amounts billed to customers is recorded on the Consolidated Balance Sheets

as under-recovered or over-recovered fuel and gas cost to be included in future customer billings. Therefore, increases in these tracked operating expenses are offset by increases in operating revenues and have essentially no impact on net income.

Changes in Operating Expenses *(in millions)*		**Favorable (Unfavorable) 2024 vs 2023**
Higher depreciation and amortization expense driven by new base rates	$	(91.1)
Higher employee and administrative expenses		(21.8)
Higher outside services expenses		(8.6)
Higher environmental remediation costs		(4.7)
Lower materials and supplies		8.9
Renewable Joint Venture operating expense, partially offset by Joint Venture operating revenues		7.6
Other		5.3
Change in operating expenses (before cost of energy and other tracked items)	$	(104.4)
Operating expenses offset in operating revenue		
Lower cost of energy billed to customers		270.8
Higher tracker deferrals within operation and maintenance, depreciation and tax		32.4
Reduction in gross receipts tax, offset in operating revenues		(1.1)
Total change in operating expense	**$**	**197.7**

Electric Supply and Generation Transition

NIPSCO continues to execute on an electric generation transition consistent with the 2018 Plan and 2021 Plan and maintained in the 2024 Plan, which outlines the path to retire the remaining two coal units at R.M. Schahfer by the end of 2025 and the remaining coal-fired generation at Michigan City by the end of 2028, to be replaced by lower-cost, reliable and cleaner options. See "Liquidity and Capital Resources" in this Management's Discussion for additional information on our capital investment spend.

NIPSCO continues to await EPA decision on an administrative approval associated with the operation of R.M. Schahfer's remaining two coal units, which are expected to be retired by the end of 2025. In the event that the approval is not obtained, future operations could be impacted. We cannot estimate the financial impact on us if this approval is not obtained. Refer to Item 1A. Risk Factors, "Operational Risks," of this Annual Report on Form 10-K for further detail.

The current replacement plan primarily includes renewable sources of energy, including wind, solar, battery storage, and flexible natural gas resources to be obtained through a combination of NIPSCO ownership and PPAs. NIPSCO has sold, and may in the future sell, renewable energy credits from its renewable generation to third parties to offset customer costs. NIPSCO has executed several PPAs to purchase 100% of the output from renewable generation facilities at a fixed price per MWh. Each facility supplying the energy will have an associated nameplate capacity, and payments under the PPAs will not begin until the associated generation facility is constructed by the owner/seller. NIPSCO has also executed several BTAs with developers to construct renewable generation facilities.

Since 2020, two wind PPA projects and six owned projects (two wind, two solar and two solar plus storage) have been placed into service totaling 2,201 MW of nameplate capacity, including Dunns Bridge II which was placed into service in January 2025. NIPSCO has executed commercial agreements for each of the six remaining identified projects. Fairbanks, Gibson, Green River, Appleseed and Carpenter have received IURC approval. The Templeton Wind project previously received approval as a PPA, however, NIPSCO has contracted with a developer to convert the PPA to a BTA and has provided a notice of intent to file a CPCN with the IURC. In January 2024, the IURC approved increases to the project costs as well as the full ownership of Cavalry and Dunns Bridge II. In August 2024, the IURC approved full ownership of Gibson and Fairbanks as well as increases to the cost of the Fairbanks project. In October 2024, the IURC approved the CPCN for NIPSCO's planned gas peaking facility to be located at the R.M. Schahfer Generating Station. See "Executive Summary - Energy Transition" in this Management's

Discussion for additional information. We expect our remaining contracted BTA and PPA projects to be placed in service between 2025 and 2027.

Remaining Renewables Projects	Transaction Type	Technology	Nameplate Capacity (MW)	Storage Capacity (MW)
Fairbanks	BTA	Solar	250	—
Gibson	BTA	Solar	200	—
Templeton	BTA[(1)]	Wind	200	—
Green River	20 year PPA	Solar	200	—
Appleseed	20 year PPA	Solar	200	—
Carpenter	20 year PPA	Wind	200	—

[(1)] Pending regulatory approval.

NISOURCE INC.

Liquidity and Capital Resources

We continually evaluate the availability of adequate financing to fund our ongoing business operations, working capital and core safety and infrastructure investment programs. Our financing is sourced through cash flow from operations and the issuance of debt and/or equity. External debt financing is provided primarily through the issuance of long-term debt, accounts receivable securitization programs and our $1.85 billion commercial paper program, which is backstopped by our committed revolving credit facility with a total availability from third-party lenders of $1.85 billion. Sources of financing activities for the current year are as follows:

- On December 31, 2023, we consummated the NIPSCO Minority Interest Transaction in exchange for a capital contribution of $2.16 billion in cash.
- On January 3, 2024, we applied the proceeds from the NIPSCO Minority Interest Transaction and repaid in full our $1.0 billion term credit agreement and our $650.0 million term credit agreement.
- On February 22, 2024, we entered into an ATM equity program that provides an opportunity to issue and sell shares of our common stock up to an aggregate issuance of $900.0 million through December 31, 2025. As of December 31, 2024, the ATM program had approximately $297.7 million of equity available for issuance.
- On March 14, 2024, we completed the issuance and sale of $650.0 million of 5.350% senior unsecured notes maturing in 2034, which resulted in approximately $642.6 million of net proceeds after discount and debt issuance costs.
- On March 15, 2024, we redeemed all 20,000 outstanding shares of Series B Preferred Stock for a redemption price of $25,000 per share and all 20,000 outstanding shares of Series B-1 Preferred Stock for a redemption price of $0.01 per share or $500.0 million in total.
- On May 16, 2024, we completed the issuance and sale of $500.0 million of 6.950% fixed-to-fixed reset rate junior subordinated notes maturing in 2054, which resulted in approximately $493.4 million of net proceeds after debt issuance costs.
- On June 24, 2024, we completed the issuance and sale of $600.0 million of 5.200% senior unsecured notes maturing in 2029, which resulted in approximately $593.7 million of net proceeds after discount and debt issuance costs.
- On September 9, 2024, we completed the issuance and sale of $500.0 million of 6.375% fixed-to-fixed reset rate junior subordinated notes maturing in 2055, which resulted in approximately $493.6 million of net proceeds after debt issuance costs.

See Note 4, "Noncontrolling Interests,", Note 6, "Equity," Note 7, "Short-Term Borrowings," and Note 8, "Long-Term Debt," in the Notes to the Consolidated Financial Statements for more information.

We believe these sources provide adequate capital to fund our operating activities and capital expenditures in 2025 and beyond.

Operating Activities

Net cash from operating activities for the year ended December 31, 2024 was $1,781.5 million, a decrease of $153.6 million from 2023. This decrease in cash from operating activities was primarily driven by year over year change in accounts receivable collections and exchange gas receivables due to the impact of lower gas prices, offset by a year over year increase in revenue, net of cost of energy and higher accounts payables due to increased gas purchases.

Investing Activities

Net cash used for investing activities for the year ended December 31, 2024 was $3,213.0 million, a decrease of $358.6 million from 2023. Lower current year investing activities were primarily driven by lower milestone payments to renewable generation asset developers for certain of our BTA projects in 2024 compared to 2023.

NiSource Inc.

Capital Expenditures. The table below reflects actual capital expenditures and certain other investing activities by segment for 2024.

	Actual
(in millions)	**2024**
Columbia Operations	
System Growth and Tracker	**$ 923.0**
Maintenance	**286.0**
Total Columbia Operations	**1,209.0**
NIPSCO Operations	
System Growth and Tracker	**754.0**
Maintenance	**492.0**
Generation Transition Investments	**1,006.4**
Total NIPSCO Operations	**2,252.4**
Corporate and Other Operations - Maintenance[(1)]	**231.1**
Total Capital Expenditures[(2)]	**$ 3,692.5**

(1) Certain amounts may subsequently be allocated out of Corporate and Other Maintenance Costs to the Columbia Operations and NIPSCO Operations segments when placed in service.
(2) Amounts differ from those presented on the Statements of Consolidated Cash Flows primarily due to the capitalized portion of the Corporate Incentive Plan payout, inclusion of capital expenditures included in current liabilities and AFUDC Equity.

In addition to these capital expenditures, we made $29.0 million of advanced deposits for project costs related to the construction of the R.M. Schahfer gas peaker as part of our generation transition and invested $65.7 million in deferred cloud computing costs in 2024. We also made $454.2 million of capital investments in the form of milestone payments to the renewable generation asset developers in 2023 that were recognized in capital expenditures in 2024.

We expect to make capital investments totaling approximately $19.4 billion during the 2025-2029 period related to infrastructure modernization, generation transition and customer growth. This forecast incorporates an estimated $1.6 billion of additional investment in renewable generation projects.

(in billions)	**2024 Actual**	**2025 Estimated**	**2026 Estimated**	**2027 Estimated**	**2028 Estimated**	**2029 Estimated**
Capital Investments	$3.3	$4.0 - 4.3	$3.4 - 3.7	$3.6 - 3.9	$3.7 - 4.0	$3.8 - 4.1

Regulatory Capital Programs. We are in the process of upgrading and modernizing our electric system to enhance safety and reliability by addressing aged infrastructure and deploying advanced grid technologies. We are also upgrading and modernizing our gas infrastructure to enhance safety and reliability by reducing leaks. An ancillary benefit of these programs is the reduction of GHG emissions. In 2024, we continued to move forward on core infrastructure and environmental investment programs supported by complementary regulatory and customer initiatives across all six states of our operating area.

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The following table describes the most recent vintage of our regulatory programs to recover infrastructure replacement and other federally mandated compliance investments:

(in millions)

Company	Program	Capital Investment	Investment Period	Filing Date	Costs Covered[1]
Approved					
Columbia of Pennsylvania[2]	DSIC - Q4 2024	$ 180.1	2/24-8/24	9/20/2024	Eligible project costs including piping, couplings, gas service lines, excess flow valves, risers, meter bars, meters, and other related capitalized investments to improve the distribution system.
Columbia of Ohio	IRP - 2024	$ 753.5	4/21-12/23	2/26/2024	Replacement of hazardous service lines, cast iron, wrought iron, uncoated steel, and bare steel pipe.
Columbia of Ohio	PHMSA IRP - 2024	$ 14.6	1/23-12/23	2/28/2024	Investments necessary to comply with the PHMSA Mega Rule.
Columbia of Ohio	CEP - 2024	$ 763.3	4/21-12/23	2/26/2024	Assets not included in the IRP or PHMSA IRP.
Columbia of Virginia	SAVE - 2025	$ 89.0	10/24-12/25	8/15/2024	Replacement projects that (1) enhance system safety or reliability, or (2) reduce, or potentially reduce, greenhouse gas emissions. Includes costs associated with Advanced Leak Detection and Repair.
Columbia of Kentucky	SMRP - 2024	$ 81.9	1/23-12/24	10/13/2023	Replacement of mains and inclusion of system safety investments.
NIPSCO - Electric	TDSIC - 5	$ 346.9	7/22-3/24	5/28/2024	New or replacement projects undertaken for the purpose of safety, reliability, system modernization or economic development.
NIPSCO - Gas	TDSIC - 8	$ 8.3	1/23-2/24	4/30/2024	New or replacement projects undertaken for the purpose of safety, reliability, system modernization or economic development.
NIPSCO - Gas	FMCA - 3	$ 27.0	1/23-6/24	8/27/2024	Project costs to comply with federal mandates.
Pending Commission Approval [3]					
Columbia of Kentucky[4]	SMRP - 2025	$ 128.5	1/23-12/25	10/15/2024	Replacement of mains and inclusion of system safety investments.
NIPSCO - Electric	TDSIC - 6	$ 555.0	7/22-9/24	11/26/2024	New or replacement projects undertaken for the purpose of safety, reliability, system modernization or economic development.
NIPSCO - Electric[5]	GCT - 1	$ 149.9	9/23-10/25	12/16/2024	New gas peaker generation project costs forecasted through the requested billing period May – Oct. 2025.

[1]Programs do not include any costs already included in base rates.
[2]Rate decreased to zero on December 14, 2024 with the implementation of new base rates resulting from Columbia of Pennsylvania's 2024 Rate Case.
[3]On July 30, 2024, CMD filed an application for approval of a new five-year STRIDE. On December 30, 2024, the filing was withdrawn.
[4]Rates went into effect January 2, 2025, subject to refund.
[5]Capital investment is based off of a projected amount. The capital investment has not all been incurred to date and represents a forecasted average for the billing period.

Refer to Note 12, "Regulatory Matters," in the Notes to Consolidated Financial Statements for a further discussion of regulatory developments during 2024.

Financing Activities

Common Stock, Preferred Stock and Equity Unit Sale. Refer to Note 6, "Equity," in the Notes to Consolidated Financial Statements for information on common stock, preferred stock and equity units activity.

Short-term Debt. Refer to Note 7, "Short-Term Borrowings," in the Notes to Consolidated Financial Statements for information on short-term debt.

Long-term Debt. Refer to Note 8, "Long-Term Debt," in the Notes to Consolidated Financial Statements for information on long-term debt.

Non-controlling Interest. Refer to Note 4, "Noncontrolling Interests," in the Notes to Consolidated Financial Statements for more information.

NISOURCE INC.

Sources of Liquidity

The following table displays our liquidity position as of December 31, 2024 and 2023:

Year Ended December 31, *(in millions)*	**2024**	2023
Current Liquidity		
Revolving Credit Facility	**$ 1,850.0**	$ 1,850.0
Accounts Receivable Programs[(1)]	**175.0**	383.9
Less:		
Commercial Paper	**604.6**	1,061.0
Accounts Receivable Programs Utilized	**—**	337.6
Letters of Credit Outstanding Under Credit Facility	**9.4**	9.9
Add:		
Cash and Cash Equivalents	**156.6**	2,245.4
Net Available Liquidity	**$ 1,567.6**	$ 3,070.8

[(1)]Represents the lesser of the seasonal limit or maximum borrowings supportable by the underlying receivables.

Debt Covenants. We are subject to a financial covenant under our revolving credit facility which requires us to maintain a debt to capitalization ratio that does not exceed 70%. As of December 31, 2024, the ratio was 52.6%.

Credit Ratings. The credit rating agencies periodically review our ratings, taking into account factors such as our capital structure and earnings profile. The following table includes our and NIPSCO's credit ratings and ratings outlook as of December 31, 2024. There have been no changes to our credit ratings or outlooks since February 2020.

A credit rating is not a recommendation to buy, sell or hold securities, and may be subject to revision or withdrawal at any time by the assigning rating organization.

	S&P		Moody's		Fitch	
	Rating	Outlook	Rating	Outlook	Rating	Outlook
NiSource	BBB+	Stable	Baa2	Stable	BBB	Stable
NIPSCO	BBB+	Stable	Baa1	Stable	BBB	Stable
Commercial Paper	A-2	Stable	P-2	Stable	F2	Stable

Certain of our subsidiaries have agreements that contain "ratings triggers" that require increased collateral if our credit ratings or the credit ratings of certain of our subsidiaries are below investment grade. These agreements are primarily for insurance purposes and for the physical purchase or sale of power. As of December 31, 2024, a collateral requirement of approximately $115.5 million would be required in the event of a downgrade below investment grade. In addition to agreements with ratings triggers, there are other agreements that contain "adequate assurance" or "material adverse change" provisions that could necessitate additional credit support such as letters of credit and cash collateral to transact business.

Equity. Our authorized capital stock consists of 770,000,000 shares, $0.01 par value, of which 750,000,000 are common stock and 20,000,000 are preferred stock. As of December 31, 2024, 469,822,472 shares of common stock were outstanding. For more information regarding our common and preferred stock, see Note 6, "Equity," in the Notes to Consolidated Financial Statements.

Contractual Obligations, Cash Requirements and Off-Balance Sheet Arrangements

We have certain contractual obligations requiring payments at specified periods. Our material cash requirements are detailed below. We intend to use funds from the liquidity sources referenced above to meet these cash requirements.

At December 31, 2024, we had $13,355.7 million in long-term debt, of which $1,281.2 million is current and $604.6 million in short-term borrowings outstanding.

During 2025 and 2026, we expect to make cash payments of $685.5 million and $631.2 million, respectively, related to pipeline service obligations including demand for gas transportation, gas storage and gas purchases, and $140.5 million and $24.9 million, respectively, for long lead time items related to plant equipment purchases.

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Our expected payments include employer contributions to pension and other postretirement benefits plans expected to be made in 2025. Plan contributions beyond 2025 are dependent upon a number of factors, including actual returns on plan assets, which cannot be reliably estimated at this time. In 2025, we expect to make contributions of approximately $2.3 million to our pension plans and approximately $21.3 million to our postretirement medical and life plans. Refer to Note 16, "Pension and Other Postemployment Benefits," in the Notes to Consolidated Financial Statements for more information.

We cannot reasonably estimate the settlement amounts or timing of cash flows related to certain of our long-term obligations classified as "Total Other Liabilities" on the Consolidated Balance Sheets.

We have uncertain income tax positions for which we are unable to predict when the matters will be resolved. Refer to Note 15, "Income Taxes," in the Notes to Consolidated Financial Statements for more information.

NIPSCO has executed several PPAs to purchase 100% of the output from renewable generation facilities at a fixed price per MWh. NIPSCO has also executed several BTAs with developers to construct renewable generation facilities. See Note 19, "Other Commitments and Contingencies - A. Contractual Obligations," and Note 19, "Other Commitments and Contingencies - E. Other Matters," in the Notes to Consolidated Financial Statements for additional information.

In addition, we, along with certain of our subsidiaries, enter into various agreements providing financial or performance assurance to third parties on behalf of certain subsidiaries. Such agreements include guarantees and stand-by letters of credit.

Refer to Note 19, "Other Commitments and Contingencies," in the Notes to Consolidated Financial Statements for additional information regarding our contractual obligations over the next 5 years and thereafter and our off-balance sheet arrangements.

Market Risk Disclosures

Risk is an inherent part of our businesses. The extent to which we properly and effectively identify, assess, monitor and manage each of the various types of risk involved in our businesses is critical to our profitability. We seek to identify, assess, monitor and manage, in accordance with defined policies and procedures, the following principal market risks that are involved in our businesses: commodity price risk, interest rate risk and credit risk. We manage risk through a multi-faceted process with oversight by the Risk Management Committee that requires constant communication, judgment and knowledge of specialized products and markets. Our senior management takes an active role in the risk management process and has developed policies and procedures that require specific administrative and business functions to assist in the identification, assessment and control of various risks. These may include, but are not limited to market, operational, financial, compliance and strategic risk types. In recognition of the increasingly varied and complex nature of the energy business, our risk management process, policies and procedures continue to evolve and are subject to ongoing review and modification.

Commodity Price Risk

Our gas and electric subsidiaries have commodity price risk primarily related to the purchases of natural gas and power. To manage this market risk, our subsidiaries use derivatives, including commodity futures contracts, swaps, forwards and options. We do not participate in speculative energy trading activity.

Commodity price risk resulting from derivative activities at our rate-regulated subsidiaries is limited and does not bear significant exposure to earnings risk, since our current regulatory mechanisms allow recovery of prudently incurred purchased power, fuel and gas costs through the rate-making process, including gains or losses on these derivative instruments. These changes are included in the GCA and FAC regulatory rate-recovery mechanisms. If these mechanisms were to be adjusted or eliminated, these subsidiaries may begin providing services without the benefit of the traditional rate-making process and may be more exposed to commodity price risk. For additional information, see "Results and Discussion of Operations" in this Management's Discussion.

Our subsidiaries are required to make cash margin deposits with their brokers to cover actual and potential losses in the value of outstanding exchange traded derivative contracts. The amount of these deposits, some of which are reflected in our restricted cash balance, may fluctuate significantly during periods of high volatility in the energy commodity markets.

Refer to Note 13, "Risk Management Activities," in the Notes to Consolidated Financial Statements for further information on our commodity price risk assets and liabilities as of December 31, 2024 and 2023.

NISOURCE INC.

Interest Rate Risk

We are exposed to interest rate risk as a result of changes in interest rates on borrowings under our revolving credit agreement, commercial paper program, and accounts receivable programs, which have interest rates that are indexed to short-term market interest rates. Based upon average borrowings and debt obligations subject to fluctuations in short-term market interest rates, an increase (or decrease) in short-term interest rates of 100 basis points (1%) would have increased (or decreased) interest expense by $7.9 million and $18.9 million for 2024 and 2023, respectively. We are also exposed to interest rate risk as a result of changes in benchmark rates that can influence the interest rates of future long-term debt issuances. From time to time, we may enter into forward interest rate instruments to lock in long term interest costs and/ or rates.

Credit Risk

Due to the nature of the industry, credit risk is embedded in many of our business activities. Our extension of credit is governed by a Corporate Credit Risk Management Policy which establishes guidelines for documenting management approval levels for credit limits, evaluating creditworthiness, and credit risk mitigation efforts. Exposures to credit risks are monitored by the risk management function, which is independent of commercial operations. Credit risk arises due to the possibility that a customer, supplier or counterparty will not be able or willing to fulfill its obligations on a transaction on or before the settlement date. For derivative-related contracts, credit risk arises when counterparties are obligated to deliver or purchase defined commodity units of gas or power to us at a future date per execution of contractual terms and conditions. Exposure to credit risk is measured in terms of both current obligations and the market value of forward positions net of any posted collateral such as cash and letters of credit.

The financial status of our banking partners is periodically assessed through traditional credit ratings provided by major credit rating agencies.

Other Information

Critical Accounting Estimates

We apply certain accounting policies in accordance with GAAP, which require that we make estimates and judgments that have had, and may continue to have, significant impacts on our operations and Consolidated Financial Statements. We evaluate our estimates on an ongoing basis. We base our estimates on historical experience and on various other assumptions that we believe are reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates. We believe the following represent the more significant items requiring the use of judgment in preparing our Consolidated Financial Statements:

Basis of Accounting for Rate-Regulated Subsidiaries. ASC Topic 980, *Regulated Operations*, provides that rate-regulated subsidiaries account for and report assets and liabilities consistent with the economic effect of the way in which regulators establish rates, if the rates established are designed to recover the costs of providing the regulated service and if the competitive environment makes it probable that such rates can be billed and collected. Accordingly, certain expenses and credits subject to utility regulation or rate determination normally reflected in income may be deferred on the Consolidated Balance Sheets and recognized in income as the related amounts are included in service rates and recovered from or refunded to customers. For additional information, refer to Note 12, "Regulatory Matters," in the Notes to Consolidated Financial Statements.

In the event that regulation significantly changes the opportunity for us to recover our costs in the future, all or a portion of our regulated operations may no longer meet the criteria for the application of ASC Topic 980, *Regulated Operations*. In such event, a write-down of all or a portion of our existing regulatory assets and liabilities could result. If transition cost recovery is approved by the appropriate regulatory bodies that would meet the requirements under GAAP for continued accounting as regulatory assets and liabilities during such recovery period, the regulatory assets and liabilities would be reported at the recoverable amounts. If we were unable to continue to apply the provisions of ASC Topic 980, *Regulated Operations*, we would be required to apply the provisions of ASC Topic 980-20, *Discontinuation of Rate-Regulated Accounting*. In management's opinion, our regulated subsidiaries will be subject to ASC Topic 980, *Regulated Operations* for the foreseeable future.

Certain of the regulatory assets reflected on our Consolidated Balance Sheets require specific regulatory action in order to be included in future service rates. Although recovery of these amounts is not guaranteed, we believe that these costs meet the requirements for deferral as regulatory assets. If we determine that the amounts included as regulatory assets are no longer probable of recovery, a charge to income would immediately be required to the extent of the unrecoverable amounts.

NISOURCE INC.

One of the more significant items recorded through the application of this accounting guidance is the regulatory overlay for JV accounting. The application of HLBV to consolidated VIEs generally results in the recognition of profit from the related JVs over a time frame that is different from when the regulatory return is earned. In accordance with the principles of ASC 980, we have recognized a regulatory deferral of certain amounts representing the timing difference between the profit earned from the JVs and the amount included in regulated rates to recover our approved investments in consolidated JVs. For additional information, refer to Note 1, "Nature of Operations and Summary of Significant Accounting Policies - S. Noncontrolling Interest," in the Notes to Consolidated Financial Statements.

Pension and Postretirement Benefits. We have defined benefit plans for both pension and other postretirement benefits. The calculation of the net obligations and annual expense related to the plans requires a significant degree of judgment regarding the discount rates to be used in bringing the liabilities to present value, expected long-term rates of return on plan assets, health care trend rates, and mortality rates, among other assumptions. Due to the size of the plans and the long-term nature of the associated liabilities, changes in the assumptions used in the actuarial estimates could have material impacts on the measurement of the net obligations and annual expense recognition. Differences between actuarial assumptions and actual plan results are deferred into AOCI or a regulatory balance sheet account, depending on the jurisdiction of our entity. These deferred gains or losses are then amortized into the income statement when the accumulated differences exceed 10% of the greater of the projected benefit obligation or the fair value of plan assets (known in GAAP as the "corridor" method) or when settlement accounting is triggered.

The discount rates, expected long-term rates of return on plan assets, health care cost trend rates and mortality rates are critical assumptions. Methods used to develop these assumptions are described below. While a third party actuarial firm assists with the development of many of these assumptions, we are ultimately responsible for selecting the final assumptions.

The discount rate is utilized principally in calculating the actuarial present value of pension and other postretirement benefit obligations and net periodic pension and other postretirement benefit plan costs. Our discount rates for both pension and other postretirement benefits are determined using spot rates along an AA-rated above median yield curve with cash flows matching the expected duration of benefit payments to be made to plan participants.

The expected long-term rate of return on plan assets is a component utilized in calculating annual pension and other postretirement benefit plan costs. We estimate the expected return on plan assets by evaluating expected bond returns, equity risk premiums, target asset allocations, the effects of active plan management, the impact of periodic plan asset rebalancing and historical performance. We also consider the guidance from our investment advisors in making a final determination of our expected rate of return on assets. For measurement of 2024 net periodic benefit cost, we selected a weighted-average assumption of the expected pre-tax long-term rate of return of 7.02% and 7.06% for our pension and other postretirement benefit plan assets, respectively. For measurement of 2025 net periodic benefit cost, we selected a weighted-average assumption of the expected pre-tax long-term rate of return of 7.30% and 7.09 % respectively, for our pension and other postretirement benefit plan assets.

We estimate the assumed health care cost trend rate, which is used in determining our other postretirement benefit net expense, based upon our actual health care cost experience, the effects of recently enacted legislation, third-party actuarial surveys and general economic conditions.

We utilize a full yield curve approach to estimate the service and interest components of net periodic benefit cost for pension and other postretirement benefits by applying the specific spot rates along the yield curve used in the determination of the benefit obligation to the relevant projected cash flows. For further discussion of our pension and other postretirement benefits, see Note 16, "Pension and Other Postemployment Benefits," in the Notes to Consolidated Financial Statements.

Typically, we use the Society of Actuaries' most recently published mortality data in developing a best estimate of mortality as part of the calculation of the pension and other postretirement benefit obligations. We adopted Aon's U.S. Endemic Mortality Improvement scale MP-2021, accounting for both the near-term and long-term COVID-19 impacts.

NiSource Inc.

The following tables illustrate the effects of changes in these actuarial assumptions while holding all other assumptions constant:

	Impact on December 31, 2024 Projected Benefit Obligation Increase/(Decrease)	
Change in Assumptions *(in millions)*	Pension Benefits	Other Postretirement Benefits
+50 basis points change in discount rate	$ (44.9)	$ (18.8)
-50 basis points change in discount rate	48.2	20.4

	Impact on 2024 Expense Increase/(Decrease)[(1)]	
Change in Assumptions *(in millions)*	Pension Benefits	Other Postretirement Benefits
+50 basis points change in discount rate	$ (1.6)	$ 0.3
-50 basis points change in discount rate	1.6	0.4
+50 basis points change in expected long-term rate of return on plan assets	(6.8)	(1.2)
-50 basis points change in expected long-term rate of return on plan assets	6.8	1.2

[(1)]Before labor capitalization and regulatory deferrals.

Goodwill and Other Intangible Assets. We have six goodwill reporting units, comprised of the six state operating companies within both the Columbia Operations and NIPSCO Operations reportable segments. Our goodwill assets at December 31, 2024 were $1,485.9 million, most of which resulted from the acquisition of Columbia on November 1, 2000.

As required by GAAP, we test for impairment of goodwill on an annual basis and on an interim basis when events or circumstances indicate that a potential impairment may exist. Our annual goodwill test takes place in the second quarter of each year and was performed on May 1, 2024. A quantitative ("step 1") test was completed on May 1, 2024 for all reporting units. Consistent with our historical impairment testing of goodwill, fair value of the reporting units was determined based on a weighting of income and market approaches. These approaches require significant judgments including appropriate long-term growth rates and discount rates for the income approach and appropriate multiples of earnings for peer companies and control premiums for the market approach. The discount rates were derived using peer company data compiled with the assistance of a third party valuation services firm. The discount rates used are subject to change based on changes in tax rates at both the state and federal level, debt and equity ratios at each reporting unit, U.S. Treasury interest rates and general economic conditions. The long-term growth rate was derived by evaluating historic growth rates, new business and investment opportunities beyond the near term horizon. The long-term growth rate is subject to change depending on inflationary impacts to the U.S. economy and the individual business environments in which each reporting unit operates. The Step 1 analysis performed indicated that the fair value of each of the reporting units exceeds their carrying value. As a result, no impairment charges were recorded. See Note 10, "Goodwill," in the Notes to Consolidated Financial Statements for information regarding our 2024 analyses and assumptions.

Unbilled Revenue. We record utility operating revenues when energy is delivered to our customers. However, the determination of energy sales to individual customers is based upon the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of their last meter reading are estimated and corresponding unbilled revenues are calculated. This unbilled revenue is estimated each month based upon historical usage, customer rates and weather. As of December 31, 2024, we recorded $408.1 million of customer accounts receivable for unbilled revenue. Significant fluctuations in energy demand for the unbilled period or changes in the composition of customer classes could impact the accuracy of the unbilled revenue estimate. Refer to Note 3, "Revenue Recognition," in the Notes to Consolidated Financial Statements for additional information regarding our significant judgments and estimates related to unbilled revenue recognition.

Income Taxes. The consolidated income tax provision and deferred income tax assets and liabilities, as well as any unrecognized tax benefits and valuation allowances, require use of estimates and significant management judgement. Although we believe that current estimates for deferred tax assets and liabilities are reasonable, actual results could differ from these estimates for a variety of reasons, including reasonable projections of taxable income, the ability and intent to implement tax planning strategies if necessary, and interpretations of applicable tax laws and regulations across multiple taxing jurisdictions.

NiSource Inc.

Ultimate resolution or clarification of income tax matters may result in favorable or unfavorable impacts to net income and cash flows, and adjustments to tax-related assets and liabilities could be material.

We account for uncertain income tax positions using a benefit recognition model with a two-step approach including a more-likely-than-not recognition threshold and a measurement approach based on the largest amount of tax benefit that is greater than 50% likely of being realized upon ultimate settlement. We evaluate each position based solely on the technical merits and facts and circumstances of the position, assuming the position will be examined by a taxing authority having full knowledge of all relevant information. Significant judgment is required to determine whether the recognition threshold has been met and, if so, the appropriate amount of tax benefits to be recorded in the consolidated financial statements. At December 31, 2024 and 2023, we had $21.7 million of unrecognized tax benefits. Changes in these unrecognized tax benefits may result from remeasurement of amounts expected to be realized, settlements with tax authorities and expiration of statutes of limitations.

On a quarterly basis, we evaluate our deferred tax assets by considering current and historical financial results, expectations for future taxable income and the availability of tax planning strategies that can be implemented, if necessary, to realize deferred tax assets. Failure to achieve forecasted taxable income or successfully implement tax planning strategies may affect the realization of deferred tax assets. We establish a valuation allowance when we conclude it is more likely than not that all, or a portion, of a deferred tax asset will not be realized in future periods. Significant judgment is required to determine the amount of tax benefits expected to be realized. At December 31, 2024 and 2023, we had established $6.4 million and $6.4 million, respectively, of valuation allowances (net of federal benefit) related to certain state net operating loss carryforwards. Refer to Note 15, "Income Taxes," in the Notes to Consolidated Financial Statements for additional information.

Recently Issued Accounting Pronouncements

Refer to Note 2, "Recent Accounting Pronouncements," in the Notes to Consolidated Financial Statements.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Quantitative and Qualitative Disclosures about Market Risk are reported in Item 7, “Management’s Discussion and Analysis of Financial Condition and Results of Operations – Market Risk Disclosures.”

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

NISOURCE INC.

Index	Page
Report of Independent Registered Public Accounting Firm	58
Statements of Consolidated Income	61
Statements of Consolidated Comprehensive Income	62
Consolidated Balance Sheets	63
Statements of Consolidated Cash Flows	65
Statements of Consolidated Stockholders' Equity	66
Notes to Consolidated Financial Statements	68
1. Nature of Operations and Summary of Significant Accounting Policies	68
2. Recent Accounting Pronouncements	71
3. Revenue Recognition	72
4. Noncontrolling Interests	76
5. Earnings Per Share	77
6. Equity	78
7. Short-Term Borrowings	80
8. Long-Term Debt	81
9. Property, Plant and Equipment	83
10. Goodwill	84
11. Asset Retirement Obligations	84
12. Regulatory Matters	85
13. Risk Management Activities	89
14. Fair Value	90
15. Income Taxes	93
16. Pension and Other Postretirement Benefits	96
17. Share-Based Compensation	107
18. Leases	110
19. Other Commitments and Contingencies	113
20. Accumulated Other Comprehensive Loss	116
21. Business Segment Information	117
22. Other, Net	119
23. Interest Expense, Net	120
24. Supplemental Cash Flow Information	120
Schedule II	121

NiSource Inc.
REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of NiSource Inc.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of NiSource Inc. and subsidiaries (the "Company") as of December 31, 2024 and 2023, the related consolidated statements of income, comprehensive income, stockholders' equity, and cash flows, for each of the three years in the period ended December 31, 2024, and the related notes and the schedule listed in the Index at Item 15 (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2024 and 2023, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2024, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2024, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 12, 2025, expressed an unqualified opinion on the Company's internal control over financial reporting.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current-period audit of the financial statements that were communicated or required to be communicated to the audit committee and that (1) relate to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Regulatory Matters - Impact of Rate Regulation on the Financial Statements – Refer to Notes 1, 9, and 12 to the financial statements

Critical Audit Matter Description

The Company’s primary subsidiaries are fully regulated natural gas and electric utility companies serving customers in six states. These rate-regulated subsidiaries account for and report assets and liabilities consistent with the economic effect of the manner in which regulators establish rates, if the rates established are designed to recover the costs of providing the regulated service and it is probable that such rates can be charged to and collected from customers. Certain expenses and credits subject to utility regulation or rate determination normally reflected in income are deferred on the consolidated balance sheets and are later recognized in income as the related amounts are included in customer rates and recovered from or refunded to customers.

NISOURCE INC.
REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Company's subsidiaries' rates are determined and approved in regulatory proceedings based on an analysis of the subsidiaries' costs to provide utility service and a return on, and recovery of, the subsidiaries' investment in the utility business. Regulatory decisions can have an impact on the recovery of costs, the rate of return earned on investment, and the timing and amount of assets to be recovered by rates. The respective commission's regulation of rates is premised on the full recovery of prudently incurred costs and a reasonable rate of return on invested capital. Decisions to be made by the commission in the future will impact the accounting for regulated operations, including decisions about the amount of allowable costs and return on invested capital included in rates and any refunds that may be required. While the Company has indicated it expects to recover costs from customers through regulated rates, there is a risk that the commission will not approve: (1) full recovery of the costs of providing utility service, or (2) full recovery of all amounts invested in the utility business and a reasonable return on that investment.

We identified the impact of rate regulation, specifically certain regulatory assets and liabilities at the Company's Northern Indiana Public Service Company LLC and Columbia Gas of Ohio, Inc. subsidiaries, as a critical audit matter due to the significant judgments made by management to support its assertions about certain account balances and the significant degree of subjectivity involved in assessing the likelihood of recovery of incurred costs in current or future rates due in part to uncertainty related to future decisions by the rate regulators. This required specialized knowledge of accounting for rate regulation and the rate setting process due to its inherent complexities and a significant degree of auditor judgment when performing audit procedures to evaluate the reasonableness of management's conclusions.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the application of specialized rules to account for the effects of cost-based rate regulation related to the uncertainty of future decisions by the rate regulators, specifically the Indiana Utility Regulatory Commission (IURC) and the Public Utility Commission of Ohio (PUCO), included the following, among others:

- We tested the effectiveness of management's controls over (1) the evaluation of the likelihood of (a) the recovery of costs deferred as regulatory assets in future periods, and (b) regulatory developments that may affect the likelihood of recovering costs in future rates or of a future reduction in rates; and (2) the evaluation of Hypothetical Liquidation Book Value (HLBV) accounting for the company's Renewable Joint Ventures and its impact on the Company's regulatory liability.

- We evaluated Northern Indiana Public Service Company LLC and Columbia Gas of Ohio, Inc.'s disclosures related to the financial statement impacts of rate regulation.

- We read relevant regulatory orders issued by the IURC and the PUCO, including regulatory statutes, interpretations, procedural memorandums, filings made by interveners, and other publicly available information to assess the likelihood of recovery in future rates or a future reduction in rates based on precedents of the commissions' treatment of similar costs under similar circumstances. We evaluated this external information and compared to management's recorded regulatory asset and liability balances for completeness, including the implementation of new rate orders at Northern Indiana Public Service Company LLC's gas business.

- We inspected minutes of the boards of directors for discussions of changes in legal, regulatory, or business factors which could impact management's conclusions with respect to the financial statement impacts of rate regulation.

- For the Northern Indiana Public Service Company LLC electric base rate case proceeding that is in-process, we inspected the Company's and intervenors' filings with the commission that may impact the Company's future rates, for any evidence that might contradict management's assertions related to recoverability of recorded assets.

- We inquired of management about property, plant, and equipment that may be abandoned with an emphasis on the generation strategy related to Northern Indiana Public Service Company LLC's R.M. Schahfer and Michigan City Generating Stations. We inspected minutes of the board of directors and regulatory orders and other filings with the IURC to identify evidence that may contradict management's assertion regarding probability of an abandonment.

NiSource Inc.
REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

- We read the relevant regulatory orders issued by the IURC for the Company's renewable energy investments. We evaluated the appropriateness of recognizing a regulatory liability representing timing differences between the profit allocated under the HLBV method related to the consolidated joint ventures and the allowed earnings included in regulatory rates. We also evaluated the appropriateness of the offset to the regulatory liability recorded in depreciation expense.

/s/ DELOITTE & TOUCHE LLP
Columbus, Ohio
February 12, 2025

We have served as the Company's auditor since 2002.

NiSource Inc.
STATEMENTS OF CONSOLIDATED INCOME

Year Ended December 31, *(in millions, except per share amounts)*	**2024**	2023	2022
Operating Revenues			
Customer revenues	**$ 5,282.9**	$ 5,347.8	$ 5,738.6
Other revenues	**172.2**	157.6	112.0
Total Operating Revenues	**5,455.1**	5,505.4	5,850.6
Operating Expenses			
Cost of energy	**1,132.2**	1,533.3	2,110.5
Operation and maintenance	**1,515.2**	1,494.9	1,489.4
Depreciation and amortization	**1,043.2**	908.2	820.8
Loss on impairment of assets	**6.1**	—	—
Loss (gain) on sale of assets, net	**2.9**	2.9	(104.2)
Other taxes	**300.0**	270.6	268.3
Total Operating Expenses	**3,999.6**	4,209.9	4,584.8
Operating Income	**1,455.5**	1,295.5	1,265.8
Other Income (Deductions)			
Interest expense, net	**(517.2)**	(489.6)	(361.6)
Other, net	**64.5**	8.0	52.2
Total Other Deductions, Net	**(452.7)**	(481.6)	(309.4)
Income before Income Taxes	**1,002.8**	813.9	956.4
Income Taxes	**158.1**	139.5	164.6
Net Income	**844.7**	674.4	791.8
Net income (loss) attributable to noncontrolling interest	**84.3**	(39.9)	(12.3)
Net Income attributable to NiSource	**760.4**	714.3	804.1
Preferred dividends	**(6.7)**	(42.8)	(55.1)
Preferred redemption premium	**(14.0)**	(9.8)	—
Net Income Available to Common Shareholders	**$ 739.7**	$ 661.7	$ 749.0
Earnings Per Share			
Basic Earnings Per Share	**$ 1.63**	$ 1.59	$ 1.84
Diluted Earnings Per Share	**$ 1.62**	$ 1.48	$ 1.70
Basic Average Common Shares Outstanding	**454.2**	416.1	407.1
Diluted Average Common Shares	**456.0**	447.9	442.7

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

NISOURCE INC.
STATEMENTS OF CONSOLIDATED COMPREHENSIVE INCOME

Year Ended December 31, *(in millions, net of taxes)*	**2024**	2023	2022
Net Income	**$ 844.7**	$ 674.4	$ 791.8
Other comprehensive income:			
Net unrealized gain (loss) on available-for-sale securities[(1)]	**3.3**	3.9	(13.3)
Net unrealized (loss) gain on cash flow hedges[(2)]	**(0.4)**	(0.2)	109.9
Unrecognized pension and OPEB benefit (costs)[(3)]	**0.3**	(0.2)	(6.9)
Total other comprehensive income	**3.2**	3.5	89.7
Total Comprehensive Income	**$ 847.9**	$ 677.9	$ 881.5

[(1)] Net unrealized gain (loss) on available-for-sale securities, net of $0.9 million tax expense, $1.0 million tax expense and $3.5 million tax benefit in 2024, 2023 and 2022, respectively.
[(2)] Net unrealized (loss) gain on derivatives qualifying as cash flow hedges, net of $0.1 million tax benefit, $0.1 million tax benefit and $36.4 million tax expense in 2024, 2023 and 2022, respectively.
[(3)] Unrecognized pension and OPEB benefit (costs), net of $0.3 million tax expense, $0.1 million tax benefit and $2.3 million tax benefit in 2024, 2023 and 2022, respectively.

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

NISOURCE INC.
CONSOLIDATED BALANCE SHEETS

(in millions)	**December 31, 2024**	December 31, 2023
ASSETS		
Property, Plant and Equipment		
Plant	**$ 34,152.9**	$ 30,482.1
Accumulated depreciation and amortization	**(8,699.0)**	(8,207.2)
Net Property, Plant and Equipment[(1)]	**25,453.9**	22,274.9
Investments and Other Assets		
Unconsolidated affiliates	**6.5**	5.3
Available-for-sale debt securities (amortized cost of $91.9 and $169.0, allowance for credit losses of $0.1 and $0.6, respectively)	**86.7**	159.1
Other investments	**85.5**	82.7
Total Investments and Other Assets	**178.7**	247.1
Current Assets		
Cash and cash equivalents	**156.6**	2,245.4
Restricted cash	**42.0**	35.7
Accounts receivable	**987.9**	884.9
Allowance for credit losses	**(23.7)**	(22.9)
Accounts receivable, net	**964.2**	862.0
Gas storage	**179.6**	265.8
Materials and supplies, at average cost	**173.3**	172.1
Electric production fuel, at average cost	**36.2**	65.3
Exchange gas receivable	**45.7**	66.0
Regulatory assets	**319.9**	214.3
Deposits to renewable generation asset developer	**—**	454.2
Prepayments	**138.5**	105.5
Other current assets	**24.2**	13.1
Total Current Assets[(1)]	**2,080.2**	4,499.4
Other Assets		
Regulatory assets	**2,157.4**	2,245.9
Goodwill	**1,485.9**	1,485.9
Deferred charges and other	**432.0**	324.0
Total Other Assets	**4,075.3**	4,055.8
Total Assets	**$ 31,788.1**	$ 31,077.2

[(1)]Includes $1,323.8 million and $1,369.8 million in 2024 and 2023, respectively, of net property, plant and equipment assets, $65.0 million and $63.6 million in 2024 and 2023, respectively, of current assets of consolidated VIEs that may be used only to settle obligations of the consolidated VIEs. Refer to Note 4, "Noncontrolling Interests," for additional information.

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

NISOURCE INC.
CONSOLIDATED BALANCE SHEETS

(in millions, except share amounts)	**December 31, 2024**	December 31, 2023
CAPITALIZATION AND LIABILITIES		
Capitalization		
Stockholders' Equity		
Common stock - $0.01 par value, 750,000,000 shares authorized; 469,822,472 and 447,381,671 shares outstanding, respectively	**$ 4.7**	$ 4.5
Preferred stock - $0.01 par value, 20,000,000 shares authorized; 0 and 40,000 shares outstanding, respectively	**—**	486.1
Treasury stock	**(99.9)**	(99.9)
Additional paid-in capital	**9,521.5**	8,879.5
Retained deficit	**(711.7)**	(967.0)
Accumulated other comprehensive loss	**(30.4)**	(33.6)
Total NiSource Stockholders' Equity	**8,684.2**	8,269.6
Noncontrolling interest in consolidated subsidiaries	**1,984.1**	1,866.7
Total Stockholders' Equity	**10,668.3**	10,136.3
Long-term debt, excluding amounts due within one year	**12,074.5**	11,055.5
Total Capitalization	**22,742.8**	21,191.8
Current Liabilities		
Current portion of long-term debt	**1,281.2**	23.8
Short-term borrowings	**604.6**	3,048.6
Accounts payable	**863.1**	749.4
Customer deposits and credits	**268.8**	294.4
Taxes accrued	**173.4**	166.2
Interest accrued	**157.0**	136.1
Asset retirement obligations	**84.6**	72.5
Exchange gas payable	**91.8**	50.5
Regulatory liabilities	**150.5**	278.6
Accrued compensation and employee benefits	**268.2**	227.6
Other accruals	**170.2**	217.4
Total Current Liabilities[(1)]	**4,113.4**	5,265.1
Other Liabilities		
Deferred income taxes	**2,281.6**	2,080.4
Accrued liability for postretirement and postemployment benefits	**207.5**	250.1
Regulatory liabilities	**1,431.2**	1,510.7
Asset retirement obligations	**698.6**	480.5
Other noncurrent liabilities and deferred credits	**313.0**	298.6
Total Other Liabilities[(1)]	**4,931.9**	4,620.3
Commitments and Contingencies (Refer to Note 19, "Other Commitments and Contingencies")		
Total Capitalization and Liabilities	**$ 31,788.1**	$ 31,077.2

[(1)]Includes $53.7 million and $68.3 million in 2024 and 2023, respectively, of current liabilities, $58.3 million and $55.7 million in 2024 and 2023, respectively, of other liabilities, and finance leases of $40.4 million in 2024, of consolidated VIEs that creditors do not have recourse to our general credit. Refer to Note 4, "Noncontrolling Interests," for additional information.

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

NISOURCE INC.
STATEMENTS OF CONSOLIDATED CASH FLOWS

Year Ended December 31, *(in millions)*	2024	2023	2022
Operating Activities			
Net Income	**$ 844.7**	$ 674.4	$ 791.8
Adjustments to Reconcile Net Income to Net Cash from Operating Activities:			
Depreciation and amortization	**1,043.2**	908.2	820.8
Deferred income taxes	**168.0**	134.1	156.9
Stock compensation expense and 401(k) profit sharing contribution	**43.6**	33.5	24.9
Loss (gain) on sale of assets	**2.9**	2.9	(105.3)
Payments for assets retirement obligations	**(72.5)**	(41.6)	(22.3)
Other adjustments	**(52.8)**	(17.9)	5.7
Changes in Assets and Liabilities:			
Accounts receivable	**(101.5)**	184.1	(216.3)
Gas storage and other inventories	**102.0**	233.9	(258.9)
Accounts payable	**71.5**	(171.8)	165.0
Exchange gas receivable/payable	**(133.5)**	126.5	57.8
Other accruals	**9.5**	(102.9)	73.4
Prepayments and other current assets	**(75.9)**	36.7	(9.8)
Regulatory assets/liabilities	**(8.7)**	(26.2)	(129.4)
Postretirement and postemployment benefits	**(64.3)**	(22.0)	84.7
Deferred charges and other noncurrent assets	**(20.8)**	(10.1)	(4.1)
Other noncurrent liabilities and deferred credits	**26.1**	(6.7)	(25.5)
Net Cash Flows from Operating Activities	**1,781.5**	1,935.1	1,409.4
Investing Activities			
Capital expenditures	**(2,614.0)**	(2,645.8)	(2,203.1)
Insurance recoveries	**0.8**	3.0	105.0
Cost of removal	**(166.8)**	(160.8)	(151.7)
Purchases of available-for-sale securities	**(17.8)**	(42.8)	(73.5)
Sales of available-for-sale securities	**93.2**	39.9	75.7
Milestone and final payments to renewable generation asset developer	**(482.0)**	(761.4)	(323.9)
Advanced deposits for project costs	**(29.0)**	—	—
Other investing activities	**2.6**	(3.7)	1.3
Net Cash Flows used for Investing Activities	**(3,213.0)**	(3,571.6)	(2,570.2)
Financing Activities			
Proceeds from issuance of long-term debt	**2,229.5**	1,488.7	345.6
Repayments of long-term debt and finance lease obligations	**(25.6)**	(33.1)	(60.3)
Repayment of short term credit agreements	**(1,650.0)**	—	—
Issuance of short term credit agreements	**—**	650.0	1,000.0
Net change in commercial paper and other short-term borrowings	**(794.0)**	636.4	202.2
Issuance of common stock, net of issuance costs	**612.6**	12.9	154.3
Redemption of preferred stock	**(486.1)**	(393.9)	—
Preferred stock redemption premium	**(14.0)**	(6.2)	—
Payment of obligation to renewable generation asset developer	**—**	(347.2)	—
Equity costs, premiums and other debt related costs	**(67.3)**	(30.2)	(13.0)
Contributions from NIPSCO minority interest holders	**99.5**	2,161.9	—
Distributions to NIPSCO minority interest holders	**(50.3)**	—	—
Contributions from tax equity partners	**—**	240.9	21.2
Distributions to tax equity partners	**(16.1)**	(14.1)	(6.0)
Dividends paid - common stock	**(481.0)**	(413.5)	(381.5)
Dividends paid - preferred stock	**(8.2)**	(43.8)	(55.1)
Contract liability payment	**—**	(66.6)	(66.1)
Net Cash Flows (used for) from Financing Activities	**(651.0)**	3,842.2	1,141.3
Change in cash, cash equivalents and restricted cash	**(2,082.5)**	2,205.7	(19.5)
Cash, cash equivalents and restricted cash at beginning of period	**2,281.1**	75.4	94.9
Cash, Cash Equivalents and Restricted Cash at End of Period	**$ 198.6**	$ 2,281.1	$ 75.4

Reconciliation to Balance Sheet	2024	2023	2022
Cash and cash equivalents	**156.6**	2,245.4	40.8
Restricted Cash	**42.0**	35.7	34.6
Total Cash, Cash Equivalents and Restricted Cash	**198.6**	2,281.1	75.4

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

NISOURCE INC.
STATEMENTS OF CONSOLIDATED STOCKHOLDERS' EQUITY

(in millions)	Common Stock	Preferred Stock[1]	Treasury Stock	Additional Paid-In Capital	Retained Deficit	Accumulated Other Comprehensive Loss	Noncontrolling Interest in Consolidated Subsidiaries	Total
Balance as of January 1, 2022	**$ 4.1**	**$ 1,546.5**	**$ (99.9)**	**$ 7,204.3**	**$ (1,580.9)**	**$ (126.8)**	**$ 325.6**	**$ 7,272.9**
Comprehensive Income:								
Net Income (Loss)	—	—	—	—	804.1	—	(12.3)	791.8
Other comprehensive income, net of tax	—	—	—	—	—	89.7	—	89.7
Dividends:								
Common stock ($0.94 per share)	—	—	—	—	(381.7)	—	—	(381.7)
Preferred stock (See Note 6)	—	—	—	—	(55.1)	—	—	(55.1)
Noncontrolling Interests:								
Contributions from noncontrolling interest	—	—	—	—	—	—	19.1	19.1
Distributions to noncontrolling interest	—	—	—	—	—	—	(6.0)	(6.0)
Stock issuances:								
Employee stock purchase plan	—	—	—	5.2	—	—	—	5.2
Long-term incentive plan	—	—	—	14.3	—	—	—	14.3
401(k) and profit sharing	—	—	—	9.7	—	—	—	9.7
ATM Program	0.1	—	—	141.8	—	—	—	141.9
Balance as of December 31, 2022	**$ 4.2**	**$ 1,546.5**	**$ (99.9)**	**$ 7,375.3**	**$ (1,213.6)**	**$ (37.1)**	**$ 326.4**	**$ 7,901.8**
Comprehensive Income:								
Net Income (Loss)	—	—	—	—	714.3	—	(39.9)	674.4
Other comprehensive income, net of tax	—	—	—	—	—	3.5	—	3.5
Dividends:								
Common stock ($1.00 per share)	—	—	—	—	(414.1)	—	—	(414.1)
Preferred stock (See Note 6)	—	—	—	—	(43.8)	—	—	(43.8)
Noncontrolling Interests:								
Issuance of noncontrolling interests[2]	—	—	—	809.6	—	—	1,361.1	2,170.7
Contributions from noncontrolling interest[3]	—	—	—	—	—	—	233.2	233.2
Distributions to noncontrolling interest	—	—	—	—	—	—	(14.1)	(14.1)
Stock issuances:								
Equity Units	0.3	(666.5)	—	666.2	—	—	—	—
Series A Preferred stock redemption	—	(393.9)	—	—	—	—	—	(393.9)
Series A Preferred stock redemption premium	—	—	—	—	(9.8)	—	—	(9.8)
Employee stock purchase plan	—	—	—	5.9	—	—	—	5.9
Long-term incentive plan	—	—	—	12.6	—	—	—	12.6
401(k) and profit sharing	—	—	—	9.9	—	—	—	9.9
Balance as of December 31, 2023	**$ 4.5**	**$ 486.1**	**$ (99.9)**	**$ 8,879.5**	**$ (967.0)**	**$ (33.6)**	**$ 1,866.7**	**$ 10,136.3**
Comprehensive Income:								
Net Income	—	—	—	—	760.4	—	84.3	844.7
Other comprehensive income, net of tax	—	—	—	—	—	3.2	—	3.2
Dividends:								
Common stock ($1.06 per share)	—	—	—	—	(483.0)	—	—	(483.0)
Preferred stock (See Note 6)	—	—	—	—	(8.1)	—	—	(8.1)
Noncontrolling Interests:								
Contributions from noncontrolling interest	—	—	—	—	—	—	99.5	99.5
Distributions to noncontrolling interests	—	—	—	—	—	—	(66.4)	(66.4)
Stock issuances (redemptions):								
Series B and B-1 Preferred stock redemption	—	(486.1)	—	—	—	—	—	(486.1)
Series B and B-1 Preferred stock redemption premium	—	—	—	—	(14.0)	—	—	(14.0)
Employee stock purchase plan	—	—	—	6.4	—	—	—	6.4
Long-term incentive plan	—	—	—	26.6	—	—	—	26.6
401(k) and profit sharing	—	—	—	9.2	—	—	—	9.2
ATM Program	0.2	—	—	599.8	—	—	—	600.0
Balance as of December 31, 2024	**$ 4.7**	**$ —**	**$ (99.9)**	**$ 9,521.5**	**$ (711.7)**	**$ (30.4)**	**$ 1,984.1**	**$ 10,668.3**

[1] Series A, Series B and Series C shares had an aggregate liquidation preference of $400M, $500M and $863M, respectively.
[2] Relates to the NIPSCO Minority Interest Transaction. See Note 4, "Noncontrolling Interests," for additional discussion.
[3] Contributions from noncontrolling interest is net of transaction costs.

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

NISOURCE INC.
STATEMENTS OF CONSOLIDATED STOCKHOLDERS' EQUITY (continued)

	Preferred	Common		
(in thousands)	**Shares**	**Shares**	**Treasury**	**Outstanding**
Balance as of January 1, 2022	**1,303**	**409,266**	**(3,963)**	**405,303**
Issued:				
Employee stock purchase plan	—	186	—	186
Long-term incentive plan	—	375	—	375
401(k) and profit sharing plan	—	337	—	337
ATM Program	—	5,942	—	5,942
Balance as of December 31, 2022	**1,303**	**416,106**	**(3,963)**	**412,143**
Issued:				
Employee stock purchase plan	—	216	—	216
Long-term incentive plan	—	758	—	758
401(k) and profit sharing plan	—	366	—	366
Equity Units[(1)]	—	33,899	—	33,899
Redeemed:				
Equity Units[(1)]	(863)	—	—	—
Series A Preferred Stock	(400)	—	—	—
Balance as of December 31, 2023	**40**	**451,345**	**(3,963)**	**447,382**
Issued:				
Employee stock purchase plan	—	218	—	218
Long-term incentive plan	—	769	—	769
401(k) and profit sharing plan	—	309	—	309
ATM Program	—	21,144	—	21,144
Redeemed:				
Series B and B-1 Preferred Stock	(40)	—	—	—
Balance as of December 31, 2024	**—**	**473,785**	**(3,963)**	**469,822**

[(1)]See Note 6, "Equity," for additional information.

The accompanying Notes to Consolidated Financial Statements are an integral part of these statements.

1. Nature of Operations and Summary of Significant Accounting Policies

A. Company Structure and Principles of Consolidation. We are an energy holding company incorporated in Delaware and headquartered in Merrillville, Indiana. Our subsidiaries are fully regulated natural gas and electric utility companies serving approximately 3.8 million customers in six states. We generate substantially all of our operating income through these rate-regulated businesses. The consolidated financial statements include the accounts of us, our majority-owned subsidiaries, and VIEs of which we are the primary beneficiary after the elimination of all intercompany accounts and transactions.

B. Use of Estimates. The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

C. Cash, Cash Equivalents and Restricted Cash. We consider all highly liquid investments with original maturities of three months or less to be cash equivalents. We report amounts deposited in brokerage accounts for margin requirements as restricted cash. In addition, we have amounts deposited in trusts to satisfy requirements for the provision of various property, liability, workers compensation, and long-term disability insurance, and holdbacks related to certain joint venture development agreements which is classified as restricted cash on the Consolidated Balance Sheets and disclosed with cash and cash equivalents on the Statements of Consolidated Cash Flows.

D. Accounts Receivable and Unbilled Revenue. Accounts receivable on the Consolidated Balance Sheets includes both billed and unbilled amounts. Unbilled amounts of accounts receivable relate to a portion of a customer's consumption of gas or electricity from their last cycle billing date through the last day of the month (balance sheet date). Factors taken into consideration when estimating unbilled revenue include historical usage, customer rates, weather and reasonable and supportable forecasts. Accounts receivable fluctuates from year to year depending in large part on weather impacts and price volatility. Our accounts receivable on the Consolidated Balance Sheets include unbilled revenue, less reserves. The reserve for uncollectible receivables is our best estimate of the amount of probable credit losses in the existing accounts receivable. We determined the reserve based on historical collection experience, current market conditions and reasonable and supportable forecasts. Account balances are charged against the allowance when it is anticipated the receivable will not be recovered. Refer to Note 3, "Revenue Recognition," for additional information on customer-related accounts receivable, including amounts related to unbilled revenues.

E. Investments in Debt Securities. Our investments in debt securities are carried at fair value and are designated as available-for-sale. These investments are included within "Available-for-sale debt securities" on the Consolidated Balance Sheets. Unrealized gains and losses, net of deferred income taxes, are recorded to accumulated other comprehensive income or loss. At each reporting period these investments are qualitatively and quantitatively assessed to determine whether a decline in fair value below the amortized cost basis has resulted from a credit loss or other factors. Impairments related to credit loss are recorded through an allowance for credit losses. Impairments that are not related to credit losses are included in other comprehensive income and are reflected in the Statements of Consolidated Income. No material impairment charges were recorded for the years ended December 31, 2024, 2023 or 2022. Refer to Note 14, "Fair Value," for additional information.

F. Basis of Accounting for Rate-Regulated Subsidiaries. Rate-regulated subsidiaries account for and report assets and liabilities consistent with the economic effect of the way in which regulators establish rates, if the rates established are designed to recover the costs of providing the regulated service and it is probable that such rates can be billed and collected. Certain expenses and credits subject to utility regulation or rate determination that would normally be reflected in income for non-regulated entities are deferred on the Consolidated Balance Sheets and are later recognized in income as the related amounts are included in customer rates and recovered from or refunded to customers.

We continually evaluate whether or not our operations are within the scope of ASC 980 and rate regulations. As part of that analysis, we evaluate probability of recovery for our regulatory assets. In management's opinion, our regulated subsidiaries will be subject to regulatory accounting for the foreseeable future. Refer to Note 12, "Regulatory Matters," for additional information.

G. Plant and Other Property and Related Depreciation and Maintenance. Property, plant and equipment (principally utility plant) is stated at cost. Our rate-regulated subsidiaries record depreciation using composite rates on a straight-line basis over the remaining service lives of the electric, gas and common properties, as approved by the appropriate regulators.

Non-utility property, consisting of renewable generation assets owned by JVs of which we are the primary beneficiary and certain retired regulatory assets described below, is generally depreciated over the life of the associated assets. Refer to Note 9, "Property, Plant and Equipment," for additional information related to depreciation expense.

For rate-regulated companies where provided for in rates, AFUDC is capitalized on all classes of property except organization costs, land, autos, office equipment, tools and other general property purchases. The allowance is applied to construction costs for that period of time between the date of the expenditure and the date on which such project is placed in service. Our consolidated pre-tax rate for AFUDC was 4.8% in 2024, 3.9% in 2023 and 3.4% in 2022.

Generally, our subsidiaries follow the practice of charging maintenance and repairs, including the cost of removal of minor items of property, to expense as incurred. When our subsidiaries retire regulated property, plant and equipment, original cost plus the cost of retirement, less salvage value, is charged to accumulated depreciation. However, when it becomes probable a regulated asset will be retired substantially in advance of its original expected useful life or is abandoned, the cost of the asset and the corresponding accumulated depreciation is recognized as a separate asset. If the asset is still in operation, the gross amounts are classified as "Non-Utility and Other " as described in Note 9, "Property, Plant and Equipment." If the asset is no longer operating but still subject to recovery, the net amount is classified in "Regulatory assets" on the Consolidated Balance Sheets. If we are able to recover a full return of and on investment, the carrying value of the asset is based on historical cost. If we are not able to recover a full return on investment, a loss on impairment is recognized to the extent the net book value of the asset exceeds the present value of future revenues discounted at the incremental borrowing rate.

External and internal costs associated with on-premise computer software developed for internal use are capitalized. Capitalization of such costs commences upon the completion of the preliminary stage of each project. Once the installed software is ready for its intended use, such capitalized costs are amortized on a straight-line basis generally over a period of five years. External and internal up-front implementation costs associated with cloud computing arrangements that are service contracts are deferred on the Consolidated Balance Sheets, with the associated internal-use software capitalized to plant if the we have a contractual right to take possession of the software at any time during the hosting period without significant penalty and it is feasible for us to either run the software on our own hardware or contract with another party unrelated to the vendor to host the software. Once the installed software is ready for its intended use, such deferred costs are amortized on a straight-line basis to "Operation and maintenance," over the minimum term of the contract plus contractually-provided renewal periods that are reasonably expected to be exercised.

H. Goodwill and Other Intangible Assets. Substantially all of our goodwill relates to the excess of cost over the fair value of the net assets acquired in the Columbia acquisition on November 1, 2000. We test our goodwill for impairment annually as of May 1, or more frequently if events and circumstances indicate that goodwill might be impaired. Fair value of our reporting units is determined using a combination of income and market approaches. See Note 10, "Goodwill," for additional information.

I. Accounts Receivable Transfer Programs. Certain of our subsidiaries have agreements with third parties to transfer certain accounts receivable without recourse. These transfers of accounts receivable are accounted for as secured borrowings. The entire gross receivables balance remains on the December 31, 2024 and 2023 Consolidated Balance Sheets. When amounts are securitized, the short-term debt is recorded in the amount of proceeds received from the transferees involved in the transactions. Refer to Note 7, "Short-Term Borrowings," for further information.

J. Gas Cost and Fuel Adjustment Clause. Our regulated subsidiaries defer most differences between gas and fuel purchase costs and the recovery of such costs in revenues and adjust future billings for such deferrals on a basis consistent with applicable state-approved tariff provisions. These deferred balances are recorded as "Regulatory assets" or "Regulatory liabilities," as appropriate, on the Consolidated Balance Sheets. Refer to Note 12, "Regulatory Matters," for additional information.

K. Gas Storage and Other Inventories. Both the LIFO inventory methodology and the weighted average cost methodology are used to value natural gas in storage, as approved by regulators for all of our regulated subsidiaries. Inventory valued using LIFO was $43.8 million and $43.9 million at December 31, 2024 and 2023, respectively. Based on the average cost of gas using the LIFO method, the estimated replacement cost of gas in storage was less than the stated LIFO cost by $12.8 million at December 31, 2024 and was less than the stated LIFO cost by $22.5 million at December 31, 2023. As all LIFO inventory costs are collected from customers through our rate-regulated subsidiaries, no inventory impairment has been recorded. Gas inventory valued using the weighted average cost methodology was $135.8 million at December 31, 2024 and $222.0 million at December 31, 2023.

Electric production fuel is valued using the weighted average cost inventory methodology, as approved by NIPSCO's regulator.

Materials and supplies are valued using the weighted average cost inventory methodology. Materials and supplies are charged to expense or capitalized to property, plant and equipment when issued.

L. Accounting for Exchange and Balancing Arrangements of Natural Gas. Our Columbia Operations and NIPSCO Operations segment enters into balancing and exchange arrangements of natural gas as part of its operations and off-system sales programs. We record a receivable or payable for any of our respective cumulative gas imbalances, as well as for any gas inventory borrowed or lent under an exchange agreement. Exchange gas is valued based on individual regulatory jurisdiction requirements (for example, historical spot rate, spot at the beginning of the month). These receivables and payables are recorded as “Exchange gas receivable” or “Exchange gas payable” on our Consolidated Balance Sheets, as appropriate.

M. Accounting for Risk Management Activities. We account for our derivatives and hedging activities in accordance with ASC 815. We recognize all derivatives as either assets or liabilities on the Consolidated Balance Sheets at fair value, unless such contracts are exempted as a normal purchase normal sale under the provisions of the standard. The accounting for changes in the fair value of a derivative depends on the intended use of the derivative and resulting designation.

We do not offset the fair value amounts recognized for any of our derivative instruments against the fair value amounts recognized for the right to reclaim cash collateral or obligation to return cash collateral for derivative instruments executed with the same counterparty under a master netting arrangement. See Note 13, "Risk Management Activities," for additional information.

N. Income Taxes and Investment Tax Credits. Under the asset and liability method, deferred income taxes are provided for the tax consequences of temporary differences by applying enacted statutory tax rates applicable to future years to differences between the financial statement carrying amount and the tax basis of existing assets and liabilities. Investment tax credits associated with regulated operations are deferred and amortized as a reduction to income tax expense over the estimated useful lives of the related properties. Furthermore, the tax basis of the asset is reduced by 50% of the ITCs received, resulting in a net deferred tax asset.

To the extent certain deferred income taxes of the regulated companies are recoverable or payable through future rates, regulatory assets and liabilities have been established. Regulatory assets for income taxes are primarily attributable to property-related tax timing differences for which deferred taxes had not been provided in the past when regulators did not recognize such taxes as costs in the rate-making process. Regulatory liabilities for income taxes are primarily attributable to the regulated companies’ obligation to refund to ratepayers deferred income taxes provided at rates higher than the current Federal income tax rate. Such property-related amounts are credited to ratepayers using either the average rate assumption method or the reverse South Georgia method. Non property-related amounts are credited to ratepayers consistent with state utility commission direction.

Pursuant to the Internal Revenue Code and relevant state taxing authorities, we and our subsidiaries file consolidated income tax returns for federal and certain state jurisdictions. We and our subsidiaries are parties to a tax sharing agreement. Income taxes recorded by each party represent amounts that would be owed had the party been separately subject to tax.

O. Pension Remeasurement. We utilize a third-party actuary for the purpose of performing actuarial valuations of our defined benefit plans. Annually, as of December 31, we perform a remeasurement for our defined benefit plans. Quarterly, we monitor for significant events, and if a significant event is identified, we perform a qualitative and quantitative assessment to determine if the resulting remeasurement would materially impact the NiSource financial statements. If material, an interim remeasurement is performed. See Note 16, "Pension and Other Postemployment Benefits," for additional information.

P. Environmental Expenditures. We accrue for costs associated with environmental remediation obligations, including expenditures related to asset retirement obligations and cost of removal, when the incurrence of such costs is probable and the amounts can be reasonably estimated, regardless of when the expenditures are actually made. The estimated future expenditures are based on currently enacted laws and regulations, existing technology and estimated site-specific costs where assumptions may be made about the nature and extent of site contamination, the extent of cleanup efforts, costs of alternative cleanup methods and other variables. The liability is adjusted as further information is discovered or circumstances change. The accruals for estimated environmental expenditures are recorded on the Consolidated Balance Sheets in “Other accruals” for short-term portions of these liabilities and “Other noncurrent liabilities and deferred credits” for the respective long-term portions of these liabilities. Rate-regulated subsidiaries applying regulatory accounting establish regulatory assets on the Consolidated Balance

Sheets to the extent that future recovery of environmental remediation costs is probable through the regulatory process. Refer to Note 11, "Asset Retirement Obligations," and Note 19, "Other Commitments and Contingencies," for further information.

Q. Excise Taxes. As an agent for some state and local governments, we invoice and collect certain excise taxes levied by state and local governments on customers and record these amounts as liabilities payable to the applicable taxing jurisdiction. Such balances are presented within "Other accruals" on the Consolidated Balance Sheets. These types of taxes collected from customers, comprised largely of sales taxes, are presented on a net basis affecting neither revenues nor cost of sales. We account for excise taxes for which we are liable by recording a liability for the expected tax with a corresponding charge to "Other taxes" expense on the Statements of Consolidated Income.

R. Accrued Insurance Liabilities. We accrue for insurance costs related to workers compensation, automobile, property, general and employment practices liabilities based on the most probable value of each claim. In general, claim values are determined by professional, licensed loss adjusters who consider the facts of the claim, anticipated indemnification and legal expenses, and respective state rules. Claims are reviewed by us at least quarterly and an adjustment is made to the accrual based on the most current information.

S. Noncontrolling Interest. We maintain a controlling financial interest in certain of our less than wholly owned subsidiaries. We consolidate these subsidiaries as either voting interest entities or VIEs and present the third-party investors' portion of our net income (loss), net assets and comprehensive income (loss) as noncontrolling interest. Noncontrolling interest is included as a component of equity on the Consolidated Balance Sheet.

On December 31, 2023, the NIPSCO Minority Interest Transaction closed and a 19.9% equity interest in NIPSCO Holdings II, the sole owner of NIPSCO, was issued to an affiliate of Blackstone. NIPSCO Holdings II does not meet the criteria of a VIE and instead is consolidated under the voting interest model in accordance with ASC 810 as we maintain control through a majority interest in NIPSCO Holdings II. Refer to Note 4, "Noncontrolling Interests," for further discussion on the NIPSCO Minority Interest Transaction.

We fund a portion of our renewable generation assets through JVs with tax equity partners. We consolidate these JVs in accordance with ASC 810 as they are VIEs in which we hold a variable interest, and we control decisions that are significant to the JVs' ongoing operations and economic results (i.e., we are the primary beneficiary).

These JVs are subject to profit sharing arrangements in which the allocation of the JVs' cash distributions and tax benefits to members is based on factors other than members' relative ownership percentages. As such, we utilize the HLBV method to allocate proceeds to each partner at the balance sheet date based on the liquidation provisions of the related JV's operating agreement and adjust the amount of the VIE's net income attributable to us and the noncontrolling tax equity member during the period.

In each reporting period, the application of HLBV to our consolidated VIEs results in a difference between the amount of profit from the consolidated JVs and the amount included in regulated rates. As discussed above in "F. Basis of Accounting for Rate-Regulated Subsidiaries," we are subject to the accounting and reporting requirements of ASC 980. In accordance with these principles, we recognize a regulatory liability or asset for amounts representing the timing difference between the profit earned from the JVs and the amount included in regulated rates to recover our approved investments in consolidated JVs. The amounts recorded in income will ultimately reflect the amount allowed in regulated rates to recover our investments over the useful life of the projects. The offset to the regulatory liability or asset associated with our renewable investments included in regulated rates is recorded in "Depreciation expense" on the Statements of Consolidated Income.

2. Recent Accounting Pronouncements

Recently Issued Accounting Pronouncements

In November 2024, the FASB issued ASU 2024-03, *Income Statement—Reporting Comprehensive Income—Expense Disaggregation Disclosures (Subtopic 220-40)*. This pronouncement requires disaggregated disclosure of income statement expenses for public business entities. The ASU requires disclosure in tabular format of disaggregation of relevant expense captions presented on the income statement by certain natural expense categories with certain related qualitative disclosures within the notes to the financial statements. The ASU does not change the expense captions an entity presents on the income

statement. The ASU is effective for fiscal years beginning after December 15, 2026 and interim reporting periods beginning after December 15, 2027. We are currently evaluating the impacts this amendment will have on our required disclosures.

In December 2023, the FASB issued ASU 2023-09, *Income Taxes (Topic 740): Improvements to Income Tax Disclosures*. This pronouncement enhances required income tax disclosures. The pronouncement will require disclosure of specific categories and reconciling items included in the rate reconciliation, disaggregation between federal, state and local income taxes paid, and disclosure of income taxes paid by jurisdictions over a certain threshold. Additionally, the pronouncement eliminates certain required disclosures related to unrecognized tax benefits. This ASU is effective for annual periods beginning after December 15, 2024, with early adoption permitted, and is to be applied on a prospective basis with retrospective application permitted. We will implement and provide the required disclosures beginning in 2025.

Recently Adopted Accounting Pronouncements

In November 2023, the FASB issued ASU 2023-07, *Segment Reporting (Topic 280): Improvements to Reportable Segment Disclosures*. This pronouncement enhances annual and interim disclosure requirements over reportable segments, primarily through enhanced disclosures about significant segment expenses. Specifically, the pronouncement requires disclosure of significant segment expenses that are regularly provided to the Chief Operating Decision Maker ("CODM") and included within each reported measure of segment profit or loss, disclosure of an amount for other segment items representing the difference between segment revenue and segment expenses already disclosed, disclosure of all required annual disclosures for interim periods and disclosure of title and position of the CODM and how the CODM uses reported measures. The pronouncement also allows for more than one measure of segment profit if the CODM uses more than one measure in assessing segment performance. This pronouncement is effective for annual periods beginning after December 15, 2023 and interim periods within fiscal years beginning after December 15, 2024. The Company adopted this pronouncement as of December 31, 2024 with retrospective application and updated its disclosures to include significant expenses regularly provided to the CODM, the CODM's title and how the CODM utilizes reported measures. See Note 21, "Business Segment Information" for further discussion.

3. Revenue Recognition

Customer Revenues. Substantially all of our revenues are tariff-based. Under ASC 606, the recipients of our utility service meet the definition of a customer, while the operating company tariffs represent an agreement that meets the definition of a contract, which creates enforceable rights and obligations. Customers in certain of our jurisdictions participate in programs that allow for a fixed payment each month regardless of usage. Payments received that exceed the value of gas or electricity actually delivered are recorded as a liability and presented in "Customer deposits and credits" on the Consolidated Balance Sheets. Amounts in this account are reduced and revenue is recorded when customer usage exceeds payments received.

We have identified our performance obligations created under tariff-based sales as 1) the commodity (natural gas or electricity, which includes generation and capacity) and 2) delivery. These commodities are sold and / or delivered to and generally consumed by customers simultaneously, leading to satisfaction of our performance obligations over time as gas or electricity is delivered to customers. Due to the at-will nature of utility customers, performance obligations are limited to the services requested and received to date. Once complete, we generally maintain no additional performance obligations.

Transaction prices for each performance obligation are generally prescribed by each operating company’s respective tariff. Rates include provisions to adjust billings for fluctuations in fuel and purchased power costs and cost of natural gas. Revenues are adjusted for differences between actual costs, subject to reconciliation, and the amounts billed in current rates. Under or over recovered revenues related to these cost recovery mechanisms are included in "Regulatory assets" or "Regulatory liabilities" on the Consolidated Balance Sheets and are recovered from or returned to customers through adjustments to tariff rates. As we provide and deliver service to customers, revenue is recognized based on the transaction price allocated to each performance obligation. Distribution revenues are generally considered daily or "at-will" contracts as customers may cancel their service at any time (subject to notification requirements), and revenue generally represents the amount we are entitled to bill customers.

In addition to tariff-based sales, our gas distribution in both our Columbia Operations and NIPSCO Operations segments enters into balancing and exchange arrangements of natural gas as part of our operations and off-system sales programs. Performance obligations for these types of sales include transportation and storage of natural gas and can be satisfied at a point in time or over a period of time, depending on the specific transaction. For those transactions that span a period of time, we record a

receivable or payable for any cumulative gas imbalances, as well as for any gas inventory borrowed or lent under a gas distribution operations exchange agreement.

Revenue Disaggregation and Reconciliation. We disaggregate revenue from contracts with customers based upon reportable segment, as well as by customer class. As of January 1, 2024, we have changed our reportable segments from Gas Distribution Operations and Electric Operations to Columbia Operations and NIPSCO Operations. Our historical segment disclosures have been recast to be consistent with the current presentation. For additional information see Note 21, "Business Segment Information".

The Columbia Operations segment provides regulated natural gas service and transportation for residential, commercial and industrial customers in Ohio, Pennsylvania, Virginia, Kentucky, and Maryland. The NIPSCO Operations segment provides regulated gas and electric service in northern Indiana for residential, commercial and industrial customers.

Other Revenues. As permitted by accounting principles generally accepted in the United States, regulated utilities have the ability to earn certain types of revenue that are outside the scope of ASC 606. These revenues primarily represent revenue earned under alternative revenue programs. Alternative revenue programs represent regulator-approved mechanisms that allow for the adjustment of billings and revenue for certain approved programs. We maintain a variety of these programs, including demand side management initiatives that recover costs associated with the implementation of energy efficiency programs, as well as normalization programs that adjust revenues for the effects of weather or other external factors. Additionally, we maintain certain programs with future test periods that operate similarly to FERC formula rate programs and allow for recovery of costs incurred to replace aging infrastructure. When the criteria to recognize alternative revenue have been met, we establish a regulatory asset and present revenue from alternative revenue programs on the Statements of Consolidated Income as “Other revenues”. When amounts previously recognized under alternative revenue accounting guidance are billed, we reduce the regulatory asset and record a customer account receivable.

The tables below reconcile revenue disaggregation by customer class to segment revenue, as well as to revenues reflected on the Statements of Consolidated Income:

Year Ended December 31, 2024 (in millions)	Columbia Operations	NIPSCO Operations	Corporate and Other	Total
Gas Distribution				
Residential	$ 1,833.8	$ 531.4	$ —	$ 2,365.2
Commercial	580.3	199.2	—	779.5
Industrial	144.2	79.0	—	223.2
Off-system	42.6	—	—	42.6
Wholesale	1.2	—	—	1.2
Miscellaneous[(1)]	26.3	15.4	—	41.7
Subtotal	$ 2,628.4	$ 825.0	$ —	$ 3,453.4
Electric Generation and Power Delivery				
Residential	$ —	$ 649.9	$ —	$ 649.9
Commercial	—	620.4	—	620.4
Industrial	—	499.1	—	499.1
Wholesale	—	38.3	—	38.3
Public Authority	—	8.1	—	8.1
Miscellaneous[(1)]	—	13.7	—	13.7
Subtotal	$ —	$ 1,829.5	$ —	$ 1,829.5
Total Customer Revenues[(2)]	2,628.4	2,654.5	—	5,282.9
Other Revenues[(3)]	74.8	96.5	0.9	172.2
Total Operating Revenues	$ 2,703.2	$ 2,751.0	$ 0.9	$ 5,455.1

[(1)]Amounts included in Columbia Operations are primarily related to earnings sharing mechanisms and late fees. Amounts included in NIPSCO Operations are primarily related to revenue refunds, public repairs and property rentals.
[(2)]Customer revenue amounts exclude intersegment revenues. See Note 21, "Business Segment Information," for discussion of intersegment revenues.

[3]Amounts included in Columbia Operations primarily relate to weather normalization adjustment mechanisms. Amounts included in NIPSCO Operations primarily relate to weather normalization adjustment mechanisms, MISO multi-value projects and revenue from non-jurisdictional transmission assets.

Year Ended December 31, 2023 *(in millions)*	Columbia Operations	NIPSCO Operations	Corporate and Other	Total
Gas Distribution				
Residential	$ 1,827.5	$ 635.0	$ —	$ 2,462.5
Commercial	598.9	249.0	—	847.9
Industrial	139.0	87.0	—	226.0
Off-system	60.6	—	—	60.6
Wholesale	1.6	—	—	1.6
Miscellaneous[1]	33.4	14.8	—	48.2
Subtotal	2,661.0	985.8	—	3,646.8
Electric Generation and Power Delivery				
Residential	—	583.9	—	583.9
Commercial	—	578.1	—	578.1
Industrial	—	474.1	—	474.1
Wholesale	—	32.0	—	32.0
Public Authority	—	11.5	—	11.5
Miscellaneous[1]	—	21.4	—	21.4
Subtotal	—	1,701.0	—	1,701.0
Total Customer Revenues[2]	$ 2,661.0	$ 2,686.8	$ —	$ 5,347.8
Other Revenues[3]	72.9	83.9	0.8	157.6
Total Operating Revenues	$ 2,733.9	$ 2,770.7	$ 0.8	$ 5,505.4

[1]Amounts included in Columbia Operations are primarily related to earnings sharing mechanisms and late fees. Amounts included in NIPSCO Operations are primarily related to late fees, property rentals, revenue refunds, and adjustments.
[2]Customer revenue amounts exclude intersegment revenues. See Note 21, "Business Segment Information," for discussion of intersegment revenues.
[3]Amounts included in Columbia Operations primarily related to weather normalization adjustment mechanisms. Amounts included in NIPSCO Operations primarily related to MISO multi-value projects and revenue from non-jurisdictional transmission assets.

Year Ended December 31, 2022 *(in millions)*	Columbia Operations	NIPSCO Operations	Corporate and Other	Total
Gas Distribution				
Residential	$ 1,918.2	$ 691.5	$ —	$ 2,609.7
Commercial	672.2	267.4	—	939.6
Industrial	135.5	85.1	—	220.6
Off-system	192.9	—	—	192.9
Wholesale	2.1	—	—	2.1
Miscellaneous[(1)]	27.3	10.9	—	38.2
Subtotal	$ 2,948.2	$ 1,054.9	$ —	$ 4,003.1
Electric Generation and Power Delivery				
Residential	$ —	$ 592.4	$ —	$ 592.4
Commercial	—	571.0	—	571.0
Industrial	—	560.6	—	560.6
Wholesale	—	13.5	—	13.5
Public Authority	—	12.1	—	12.1
Miscellaneous[(1)]	—	(14.1)	—	(14.1)
Subtotal	$ —	$ 1,735.5	$ —	$ 1,735.5
Total Customer Revenues[(2)]	$ 2,948.2	$ 2,790.4	$ —	$ 5,738.6
Other Revenues[(3)]	3.7	95.8	12.5	112.0
Total Operating Revenues	$ 2,951.9	$ 2,886.2	$ 12.5	$ 5,850.6

[(1)]Amounts included in Columbia Operations are primarily related to earnings share mechanisms and late fees. Amounts included in NIPSCO Operations are primarily related to revenue trackers, late fees and property rentals.2.1
[(2)]Customer revenue amounts exclude intersegment revenues. See Note 21, "Business Segment Information," for discussion of intersegment revenues.
[(3)]Amounts included in Columbia Operations primarily related to weather normalization adjustment mechanisms. Amounts included in NIPSCO Operations primarily related to MISO multi-value projects and revenue from non-jurisdictional transmission assets. Amounts included in Corporate and Other primarily related to the Transition Services Agreement entered into in connection with the sale of the Massachusetts Business.

Customer Accounts Receivable. Accounts receivable on our Consolidated Balance Sheets includes both billed and unbilled amounts, as well as certain amounts that are not related to customer revenues. Unbilled amounts of accounts receivable relate to a portion of a customer's consumption of gas or electricity from the date of their last cycle billing through the last day of the month (balance sheet date). Factors taken into consideration when estimating unbilled revenue include historical usage, customer rates, and weather. A significant portion of our operations are subject to seasonal fluctuations in sales. During the heating season, primarily from November through March, revenues and receivables from gas sales are more significant than in other months. The opening and closing balances of customer receivables for the year ended December 31, 2024, are presented in the table below. We had no significant contract assets or liabilities during the period. Additionally, we have not incurred any significant costs to obtain or fulfill contracts.

(in millions)	Customer Accounts Receivable, Billed (less reserve)	Customer Accounts Receivable, Unbilled (less reserve)
Balance as of December 31, 2023	$ 479.4	$ 337.6
Balance as of December 31, 2024	525.1	408.1

Utility revenues are billed to customers monthly on a cycle basis. We expect that substantially all customer accounts receivable will be collected following customer billing, as this revenue consists primarily of periodic, tariff-based billings for service and usage. We maintain common utility credit risk mitigation practices, including requiring deposits and actively pursuing collection of past due amounts. Our regulated operations also utilize certain regulatory mechanisms that facilitate recovery of bad debt costs within tariff-based rates, which provides further evidence of collectibility. It is probable that substantially all of the consideration to which we are entitled from customers will be collected upon satisfaction of performance obligations.

Allowance for Credit Losses. To evaluate for expected credit losses, customer account receivables are pooled based on similar risk characteristics, such as customer type, geography, payment terms, and related macro-economic risks. Expected credit losses are established using a model that considers historical collections experience, current information, and reasonable and supportable forecasts. Internal and external inputs are used in our credit model including, but not limited to, energy consumption trends, revenue projections, actual charge-offs data, recoveries data, shut-offs, customer delinquencies, final bill data, and inflation. We continuously evaluate available information relevant to assessing collectability of current and future receivables. We evaluate creditworthiness of specific customers periodically or following changes in facts and circumstances. When we become aware of a specific commercial or industrial customer's inability to pay, an allowance for expected credit losses is recorded for the relevant amount. We also monitor other circumstances that could affect our overall expected credit losses including, but not limited to, creditworthiness of overall population in service territories, adverse conditions impacting an industry sector, and current economic conditions.

At each reporting period, we record expected credit losses to an allowance for credit losses account. When deemed to be uncollectible, customer accounts are written-off. A rollforward of our allowance for credit losses as of December 31, 2024 and December 31, 2023, are presented in the tables below:

(in millions)	Columbia Operations	NIPSCO Operations	Corporate and Other	Total
Balance as of January 1, 2024	$ 10.2	$ 11.9	$ 0.8	$ 22.9
Current period provisions	26.7	12.1	—	38.8
Write-offs charged against allowance	(43.9)	(11.0)	(0.8)	(55.7)
Recoveries of amounts previously written off	16.8	0.9	—	17.7
Balance as of December 31, 2024	$ 9.8	$ 13.9	$ —	$ 23.7

(in millions)	Columbia Operations	NIPSCO Operations	Corporate and Other	Total
Balance as of January 1, 2023	$ 11.1	$ 12.0	$ 0.8	$ 23.9
Current period provisions	28.3	11.5	—	39.8
Write-offs charged against allowance	(49.2)	(12.4)	—	(61.6)
Recoveries of amounts previously written off	20.0	0.8	—	20.8
Balance as of December 31, 2023	$ 10.2	$ 11.9	$ 0.8	$ 22.9

4. Noncontrolling Interests

Variable Interest Entities. A VIE is an entity in which the controlling interest is determined through means other than a majority voting interest. Refer to Note 1, "Nature of Operations and Summary of Significant Accounting Policies - S. Noncontrolling Interest," for information on our accounting policy for the VIEs.

NIPSCO is the managing member and operator of two wind JVs, Rosewater and Indiana Crossroads Wind, which have 102 MW and 302 MW of nameplate capacity, respectively. NIPSCO is also a managing member and operator of two solar JVs, Indiana Crossroads Solar and Dunns Bridge I, which have a nameplate capacity of 200 MW and 265 MW, respectively. We have determined that these JVs are VIEs. NIPSCO controls decisions that are significant to these entities' ongoing operations and economic results. Therefore, we have concluded that NIPSCO is the primary beneficiary and have consolidated all four entities.

Members of each respective JV include NIPSCO (who is the managing member) and a tax equity partner. Earnings, tax attributes and cash flows are allocated to both NIPSCO and the tax equity partner in varying percentages by category and over the life of the partnership. NIPSCO and each tax equity partner contributed cash to the respective JV. Once the tax equity partner has earned their negotiated rate of return and the JV has reached a stated contractual date, NIPSCO has the option to purchase the remaining interest in the respective JV from the tax equity partner. NIPSCO has an obligation to purchase 100% of the electricity generated by each commercially operational JV.

We did not provide any financial or other support during the year that was not contractually required.

Our Consolidated Balance Sheets included the following assets and liabilities associated with VIEs.

(in millions)	**December 31, 2024**	December 31, 2023
Net Property, Plant and Equipment	**$ 1,323.8**	$ 1,369.8
Current assets	**65.0**	63.6
Total assets[(1)(2)]	**1,388.8**	1,433.4
Current liabilities	**53.7**	68.3
Asset retirement obligations	**58.3**	55.7
Finance lease obligations	**40.4**	—
Total liabilities[(1)(2)]	**$ 152.4**	$ 124.0

[(1)]The assets of each VIE represent assets of a consolidated VIE that can be used only to settle obligations of the respective consolidated VIE. The creditors of the liabilities of the VIEs do not have recourse to the general credit of the primary beneficiary.
[(2)]In addition to the amounts disclosed above there is a de minimis amount of other noncurrent assets and liabilities at Rosewater as of December 31, 2024.

Voting Interest Entities. On December 31, 2023, we consummated the NIPSCO Minority Interest Transaction for a capital contribution of $2.16 billion in cash. The difference between the $2.16 billion consideration received and the $1.36 billion carrying value of the noncontrolling interest claim on net assets was recorded to additional paid-in capital, net of $54.7 million in transaction costs and a $63.5 million income tax benefit. We retain a controlling financial interest in NIPSCO Holdings II and its subsidiaries and consolidate their financial results. For the twelve months ending December 31, 2024 we received $99.5 million of contributions, and we made $50.3 million of distributions, to our NIPSCO minority interest holders. See Note 19, "Other Commitments and Contingencies - E. Other Matters," for a detailed discussion of the NIPSCO Holdings II LLC Agreement and governance structure.

5. Earnings Per Share

The calculations of basic and diluted EPS are based on the weighted average number of shares of common stock and potential common stock outstanding during the period. Diluted EPS includes the incremental effects of the various long-term incentive compensation plans and ATM forward sale agreements under the treasury stock method when the impact would be dilutive. For the purposes of determining diluted EPS, for the twelve months ended December 31, 2023 and 2022, the shares underlying the purchase contracts included within the Equity Units were included in the calculation of potential common stock outstanding using the if-converted method under US GAAP and we assumed share settlement of the remaining purchase contract payment balance from our Equity Units based on the average share price during the period. This method assumes conversion at the beginning of the reporting period, or at time of issuance, if later. The purchase contracts were settled on December 1, 2023. For the purchase contracts, the number of shares of our common stock that would have been issuable at the end of each reporting period prior to the settlement date were reflected in the denominator of our diluted EPS calculation. A numerator adjustment was reflected in the calculation of diluted EPS for interest expense incurred in 2023 and 2022, net of tax, related to the purchase contracts.

We adopted ASU 2020-06 on January 1, 2022, which required us to assume share settlement of the remaining purchase contract payment balance from our Equity Units based on the average share price during the period.

The shares underlying the Series C Mandatory Convertible Preferred Stock included within the Equity Units were contingently convertible as the conversion was contingent on a successful remarketing. Contingently convertible shares where conversion was not tied to a market price trigger were excluded from the calculation of diluted EPS until such time as the contingency had been resolved under the if-converted method. The unsuccessful remarketing resolved the contingency and no shares were reflected in the denominator for the years ended December 31, 2023 and 2022, for the calculation of diluted EPS.

We began using the two-class method of computing earnings per share in 2023 because we have participating securities in the form of non-vested restricted stock units with a non-forfeitable right to dividend equivalents, for which vesting is predicated solely on the passage of time. The calculation of earnings per share using the two-class method excludes income attributable to these participating securities from the numerator and excludes the dilutive impact of those shares from the denominator.

During 2022, we had no outstanding securities other than common and preferred stock, which required holders' participation in dividends and earnings; therefore, we were not required to calculate EPS under the two-class method. Basic net income per share is computed by dividing net income available to common shareholders by the weighted-average number of shares of common stock outstanding during the period. Diluted net income per share is computed by giving effect to all potential shares of common stock, to the extent they are dilutive. Refer to Note 6, "Equity," for additional information.

The following table presents the calculation of our basic and diluted EPS:

Year Ended December 31, *(in millions, except per share amounts)*	**2024**	2023	2022
Numerator:			
Net Income Available to Common Shareholders	**$ 739.7**	$ 661.7	$ 749.0
Less: Income allocated to participating securities	**1.6**	0.6	—
Net Income Available to Common Shareholders - Basic	**$ 738.1**	$ 661.1	$ 749.0
Add: Dilutive effect of Equity Units	**—**	1.4	2.0
Net Income Available to Common Shareholders - Diluted	**$ 738.1**	$ 662.5	$ 751.0
Denominator:			
Average common shares outstanding - Basic	**454.2**	416.1	407.1
Dilutive potential common shares:			
Equity Units purchase contracts	**—**	29.8	30.2
Equity Units purchase contract payment balance	**—**	0.9	3.2
Shares contingently issuable under employee stock plans	**0.9**	0.7	0.9
Shares restricted under employee stock plans	**0.3**	0.4	0.5
ATM Forward agreements	**0.6**	—	0.8
Average Common Shares - Diluted	**456.0**	447.9	442.7
Earnings per common share:			
Basic	**$ 1.63**	$ 1.59	$ 1.84
Diluted	**$ 1.62**	$ 1.48	$ 1.70

6. Equity

Holders of shares of our common stock are entitled to receive dividends when, as, and if declared by the Board out of funds legally available. The policy of the Board has been to declare cash dividends on a quarterly basis payable on or about the 20th day of February, May, August and November. We have certain debt covenants that could potentially limit the amount of dividends we could pay in order to maintain compliance with these covenants. Refer to Note 8, "Long-Term Debt," for more information. As of December 31, 2024, these covenants did not restrict the amount of dividends that were available to be paid.

There is no preferred stock outstanding as of December 31, 2024.

Common and preferred stock activity for 2024, 2023 and 2022 is described further below.

ATM Program. In February 2024, we entered into eight separate equity distribution agreements pursuant to which we were able to sell up to an aggregate of $900.0 million of our common stock.

In February 2024, under the ATM program, we executed a forward sale agreement, which allowed us to issue a fixed number of shares at a price to be settled in the future. The forward purchaser under our forward sale agreement borrowed 7,757,951 shares from third parties, which the forward purchaser sold, through its affiliated agent, at a weighted average price of $25.78 per share. On September 17, 2024 we settled all the shares under the forward sale agreement for $199.9 million, based on a net price of $25.77 per share.

In May 2024, under the ATM program, we executed a forward sale agreement, which allowed us to issue a fixed number of shares at a price to be settled in the future. The forward purchaser under our forward sale agreement borrowed 10,390,000 shares from third parties, which the forward purchaser sold, through its affiliated agent, at a weighted average price of $28.87 per share. On September 11, 2024 we settled all the shares under the forward sale agreement for $299.1 million, based on a net price of $28.79 per share.

In September 2024, under the ATM program, we executed a forward sale agreement, which allowed us to issue a fixed number of shares at a price to be settled in the future. The forward purchaser under our forward sale agreement borrowed 1,495,949 shares from third parties, which the forward purchaser sold, through its affiliated agent, at a weighted average price of $34.01 per share. On November 19, 2024 we settled all the shares under the forward sale agreement for $50.3 million, based on a net price of $33.64 per share.

In September 2024, under the ATM program, we executed a second forward sale agreement, which allowed us to issue a fixed number of shares at a price to be settled in the future. The forward purchasers under our forward sale agreement borrowed 1,500,000 shares from third parties, which the forward purchaser sold, through its affiliated agent, at a weighted average price of $34.32 per share. On November 20, 2024 we settled all the shares under the forward sale agreement for$51.0 million, based on a net price of $33.99 per share.

As of December 31, 2024, the ATM program had approximately $297.7 million of equity available for issuance. The program expires on December 31, 2025.

Series A Preferred Stock. During 2023, there were $28.25 dividends declared per share for the Series A Preferred Stock.

On June 15, 2023, we redeemed all 400,000 outstanding shares of Series A Preferred Stock for a redemption price of $1,000 per share or $400.0 million in total.

Series B and B-1 Preferred Stock. During 2024 and 2023, dividends declared per share for the Series B Preferred Stock were $406.25 and $1,625.0, respectively.

On March 15, 2024, we redeemed all 20,000 outstanding shares of Series B Preferred Stock for a redemption price of $25,000 per share and all 20,000 outstanding shares of Series B-1 Preferred Stock for a redemption price of $0.01 per share or $500.0 million in total. Following the redemption, dividends ceased to accrue on the shares of Series B Preferred Stock, shares of the Series B Preferred Stock and Series B-1 Preferred Stock were no longer deemed outstanding and all rights of the holders of such shares of Series B Preferred Stock and Series B-1 Preferred Stock terminated. In conjunction with the redemption, we recorded a $14.0 million preferred stock redemption premium, calculated as the difference between the carrying value on the redemption date of the Series B Preferred Stock and Series B-1 Preferred Stock and the total amount of consideration paid to redeem, which was recorded as a reduction to retained earnings during the first quarter of 2024. We did not recognize an excise tax liability under the IRA in connection with this redemption as we issued common stock in 2024 in excess of the fair value of the Series B Preferred Stock and Series B-1 Preferred Stock redeemed.

In March 2024, we filed a Certificate of Elimination to our Amended and Restated Certificate of Incorporation with the Secretary of State of Delaware to eliminate from the Amended and Restated Certificate of Incorporation all matters set forth in the Certificate of Designations with respect to the Series B Preferred Stock and the Certificate of Designations with respect to the Series B-1 Preferred Stock. As a result, the 20,000 shares that were previously designated as Series B Preferred Stock and the 20,000 shares that were previously designated as Series B-1 Preferred Stock were returned to the status of authorized but unissued shares of preferred stock, par value $0.01 per share, without designation as to series. The Certificate of Elimination does not change the total number of authorized shares of capital stock of NiSource or the total number of authorized shares of preferred stock. We voluntarily delisted the preferred stock from the New York Stock Exchange on March 15, 2024.

Equity Units. On December 1, 2023, we issued 33,898,837 shares of our common stock under the purchase contract component of the Corporate Units. As of December 1, 2023, each holder of Corporate Units was deemed to have automatically delivered to us the related Series C Mandatory Convertible Preferred Stock that were components of the Corporate Units in full satisfaction of such holder’s obligations under the related purchase contract, and all 862,500 shares of Series C Mandatory Convertible Preferred Stock were returned to the status of authorized but unissued preferred stock, par value of $0.01 per share, without designation as to series. We voluntarily delisted the Corporate Units from the New York Stock Exchange on December 1, 2023.

Refer to Note 5, "Earnings Per Share," for additional information regarding our treatment of the Equity Units for diluted EPS.

On October 21, 2024, we filed a Certificate of Elimination to our Amended and Restated Certificate of Incorporation with the Secretary of State of the State of Delaware to eliminate from the Amended and Restated Certificate of Incorporation all matters set forth in the Certificate of Designations with respect to the Series C Mandatory Convertible Preferred Stock.

Noncontrolling Interest in Consolidated Subsidiaries. As of December 31, 2024 and 2023, NIPSCO and tax equity partners have completed their cash contributions into the Indiana Crossroads Wind, Rosewater, Indiana Crossroads Solar and Dunns Bridge I JVs. Earnings, tax attributes and cash flows are allocated to both NIPSCO and the respective tax equity partners in varying percentages by category and over the life of the partnership. The tax equity partner's contributions, net of these allocations, is represented as a noncontrolling interest within total equity on the Consolidated Balance Sheets. Refer to Note 4, "Noncontrolling Interests," for more information.

On December 31, 2023, we consummated the closing of the NIPSCO Minority Interest Transaction and issued a 19.9% equity interest in NIPSCO Holdings II LLC to BIP in exchange for a capital contribution of $2.16 billion in cash. Transaction costs and deferred tax impacts of $54.7 million and $63.5 million were recorded during the period ending December 31, 2023. Refer to Note 15, "Income Taxes," and Note 19, "Other Commitments and Contingencies - E. Other Matters," in the Notes to the Consolidated Financial Statements for more information on this transaction.

7. Short-Term Borrowings

We generate short-term borrowings from our revolving credit facility, commercial paper program, accounts receivable transfer programs, and term credit agreements. Each of these borrowing sources is described further below.

Revolving Credit Facility. We maintain a revolving credit facility to fund ongoing working capital requirements, including the provision of liquidity support for our commercial paper program, provide for issuance of letters of credit, and also for general corporate purposes. Our revolving credit facility has a program limit of $1.85 billion and is comprised of a syndicate of banks. At December 31, 2024 and 2023, we had no outstanding borrowings under this facility.

Commercial Paper Program. At December 31, 2024 and December 31, 2023, our commercial paper program had a program limit of up to $1.85 billion and $1.50 billion, respectively. On February 9, 2024, we increased the program limit from $1.50 billion to $1.85 billion. We had $604.6 million and $1,061.0 million of commercial paper outstanding with weighted-average interest rates of 4.73% and 5.65% as of December 31, 2024 and 2023, respectively.

Accounts Receivable Transfer Programs. Columbia of Ohio, NIPSCO, and Columbia of Pennsylvania each maintain a receivables agreement whereby they transfer their customer accounts receivables to third party financial institutions through consolidated special purpose entities. The three agreements expire between May 2025 and October 2025 and may be further extended if mutually agreed to by the parties thereto.

All receivables transferred to third parties are valued at face value, which approximates fair value due to their short-term nature. The amount of the undivided percentage ownership interest in the accounts receivables transferred is determined in part by required loss reserves under the agreements.

Transfers of accounts receivable are accounted for as secured borrowings resulting in the recognition of short-term borrowings on the Consolidated Balance Sheets. As of December 31, 2024, the maximum amount we could borrow related to our accounts receivable programs is $175.0 million.

We had zero and $337.6 million short-term borrowings related to the securitization transactions as of December 31, 2024 and 2023, respectively.

For the year ended December 31, 2024 and 2023, $337.6 million and $9.6 million, respectively, was recorded as cash flows used for financing activities related to the change in short-term borrowings due to securitization transactions. For the accounts receivable transfer programs, we pay used facility fees for amounts borrowed, unused commitment fees for amounts not borrowed, and upfront renewal fees. Fees associated with the securitization transactions were $1.5 million, $2.7 million, and $2.5 million for the years ended December 31, 2024, 2023 and 2022, respectively. Columbia of Ohio, NIPSCO and Columbia of Pennsylvania remain responsible for collecting the receivables securitized, and the receivables cannot be transferred to another party. Refer to Note 23, "Interest Expense, Net," for additional information on securitization transaction fees.

Term Credit Agreements. At December 31, 2023, we had $1.0 billion, and $650.0 million outstanding under term credit agreements with interest rates of 6.41% and 6.50%, respectively. On January 3, 2024, we terminated and repaid in full our $1.0 billion and $650.0 million term credit agreements with proceeds from the NIPSCO Minority Interest Transaction.

Items listed above, excluding the term credit agreements, are presented net in the Statements of Consolidated Cash Flows as their maturities are less than 90 days.

8. Long-Term Debt

Our long-term debt as of December 31, 2024 and 2023 is as follows:

Long-term debt type	Maturity as of December 31, 2024	Weighted average interest rate (%)	Outstanding balance as of December 31, *(in millions)* **2024**	2023
Senior notes:				
NiSource	August 2025	0.950 %	**$1,250.0**	$1,250.0
NiSource	May 2027	3.490 %	**1,000.0**	1,000.0
NiSource	December 2027	6.780 %	**3.0**	3.0
NiSource	March 2028	5.250 %	**1,050.0**	1,050.0
NiSource	July 2029	5.200 %	**600.0**	—
NiSource	September 2029	2.950 %	**750.0**	750.0
NiSource	May 2030	3.600 %	**1,000.0**	1,000.0
NiSource	February 2031	1.700 %	**750.0**	750.0
NiSource	June 2033	5.400 %	**450.0**	450.0
NiSource	April 2034	5.350 %	**650.0**	—
NiSource	December 2040	6.250 %	**152.6**	152.6
NiSource	June 2041	5.950 %	**347.4**	347.4
NiSource	February 2042	5.800 %	**250.0**	250.0
NiSource	February 2043	5.250 %	**500.0**	500.0
NiSource	February 2044	4.800 %	**750.0**	750.0
NiSource	February 2045	5.650 %	**500.0**	500.0
NiSource	May 2047	4.375 %	**1,000.0**	1,000.0
NiSource	March 2048	3.950 %	**750.0**	750.0
NiSource	June 2052	5.000 %	**350.0**	350.0
Total senior notes			**$12,103.0**	$10,853.0
Junior subordinated notes:				
NiSource	November 2054	6.950 %	**500.0**	—
NiSource	March 2055	6.375 %	**500.0**	—
Total junior subordinated notes			**$1,000.0**	$ —
Medium term notes:				
NiSource	May 2027	7.990 %	**$ 29.0**	$ 29.0
NIPSCO	June 2027 to August 2027	7.644 %	**58.0**	58.0
Columbia of Massachusetts	December 2025 to February 2028	6.373 %	**15.0**	15.0
Total medium term notes			**$ 102.0**	$ 102.0
Finance leases:				
NiSource Corporate Services	January 2025 to September 2027	3.470 %	**$ 14.6**	$ 30.5
NIPSCO	December 2027 to November 2035	5.250 %	**124.3**	61.2
Columbia of Ohio	December 2025 to March 2044	6.150 %	**85.6**	90.3
Columbia of Virginia	July 2029 to November 2039	6.190 %	**15.2**	16.1
Columbia of Kentucky	May 2027	5.360 %	**0.1**	0.2
Columbia of Pennsylvania	July 2027 to May 2035	4.470 %	**6.4**	7.1
Total finance leases			**$ 246.2**	$ 205.4
Less: Unamortized issuance costs and discounts			**(95.5)**	(81.1)
Less: Current portion of long term debt			**(1,281.2)**	(23.8)
Total Long-Term Debt			**$12,074.5**	$11,055.5

Details of our 2024 long-term debt related activity are summarized below:

- On March 14, 2024, we completed the issuance and sale of $650.0 million of 5.350% senior unsecured notes maturing in 2034, which resulted in approximately $642.6 million of net proceeds after discount and debt issuance costs.

- On May 16, 2024, we completed the issuance and sale of $500.0 million of 6.950% fixed-to-fixed reset rate junior subordinated notes maturing in 2054, which resulted in approximately $493.4 million of net proceeds after debt issuance costs. The subordinated notes bear interest (i) from and including May 16, 2024 to, but excluding, November 30, 2029 at a rate of 6.950% per annum and (ii) from and including November 30, 2029, during each five-year reset period at a rate per annum equal to the five-year U.S. treasury rate (determined as described in the prospectus supplement dated May 13, 2024, which was filed with the SEC on May 14, 2024) as of the then most recent reset interest determination date plus a spread of 2.451%, to be reset on each reset date. At our option, we may redeem some or all of the subordinated notes during specified periods, and upon the occurrence of certain ratings or tax events, all as described in the prospectus supplement. In accordance with terms of the subordinated notes, we have the right, from time to time, to defer the payment of interest on the outstanding subordinated notes on one or more occasions for up to ten consecutive years. In the event that we were to exercise such right to defer interest on the subordinated notes, we would not be able to pay cash dividends on the common stock during the periods in which such payments were deferred. The subordinated notes were issued pursuant to a Subordinated Indenture, dated as of May 16, 2024, between us and The Bank of New York Mellon, as trustee, as supplemented by the First Supplemental Indenture thereto, dated as of May 16, 2024.
- On June 24, 2024, we completed the issuance and sale of $600.0 million of 5.200% senior unsecured notes maturing in 2029, which resulted in approximately $593.7 million of net proceeds after discount and debt issuance costs.
- On September 9, 2024, we completed the issuance and sale of $500.0 million of 6.375% fixed-to-fixed reset rate junior subordinated notes maturing in 2055, which resulted in approximately $493.6 million of net proceeds after debt issuance costs. The subordinated notes bear interest (i) from and including September 9, 2024 to, but excluding, March 31, 2035 at a rate of 6.375% per annum and (ii) from and including March 31, 2035, during each five-year reset period at a rate per annum equal to the five-year U.S. treasury rate (determined as described in the prospectus supplement dated September 3, 2024, which was filed with the SEC on September 4, 2024) as of the then most recent reset interest determination date plus a spread of 2.527%, to be reset on each reset date. At our option, we may redeem some or all of the subordinated notes during specified periods, and upon the occurrence of certain ratings or tax events, all as described in the prospectus supplement. In accordance with terms of the subordinated notes, we have the right, from time to time, to defer the payment of interest on the outstanding subordinated notes on one or more occasions for up to ten consecutive years. In the event that we were to exercise such right to defer interest on the subordinated notes, we would not be able to pay cash dividends on the common stock during the periods in which such payments were deferred. The subordinated notes were issued pursuant to a Subordinated Indenture, dated as of May 16, 2024, between us and The Bank of New York Mellon, as trustee, as supplemented by the Second Supplemental Indenture thereto, dated as of September 9, 2024.

Details of our 2023 long-term debt related activity are summarized below:

- On March 24, 2023, we completed the issuance sale of $750.0 million of 5.250% senior unsecured notes maturing in 2028, which resulted in approximately $742.2 million of net proceeds after discount and debt issuance costs.
- On June 8, 2023, we completed the issuance and sale of $300.0 million of 5.250% senior unsecured notes maturing in 2028 (the "2028 Notes"). The terms of the 2028 Notes, other than the issue date and the price to the public, are identical to the terms of, and constitute as a reopening of, our 5.250% senior unsecured notes due 2028 issued on March 24, 2023. With the incremental issuance, we now have $1.05 billion of 5.250% senior unsecured notes maturing in 2028. On June 8, 2023, we also completed the issuance and sale of $450.0 million of 5.400% senior unsecured notes maturing in 2033. These issuances resulted in approximately $742.5 million of total net proceeds after discount and debt issuance costs.

See Note 19, "Other Commitments and Contingencies - A. Contractual Obligations," for the outstanding long-term debt maturities at December 31, 2024.

Unamortized debt expense, premium and discount on long-term debt applicable to outstanding bonds are being amortized over the life of such bonds.

We are subject to a financial covenant under our revolving credit facility which requires us to maintain a debt to capitalization ratio that does not exceed 70%. As of December 31, 2024, the ratio was 52.6%.

We are also subject to certain other non-financial covenants under the revolving credit facility. Such covenants include a limitation on the creation or existence of new liens on our assets, generally exempting liens on utility assets, purchase money security interests, preexisting security interests and an additional subset of assets equal to $200 million. An asset sale covenant generally restricts the sale, conveyance, lease, transfer or other disposition of our assets to those dispositions that are for a price not materially less than fair market of such assets, that would not materially impair our ability to perform obligations under the revolving credit facility, and that together with all other such dispositions, would not have a material adverse effect. The covenant also restricts dispositions to no more than 15% of our consolidated total assets on December 31, 2022. Additionally, the revolving credit facility requires us to own directly or indirectly at least 70% of NIPSCO. The revolving credit facility also includes a cross-default provision, which triggers an event of default under the credit facility in the event of an uncured payment default relating to any indebtedness of us or any of our subsidiaries in a principal amount of $75.0 million or more.

Our indentures generally do not contain any financial maintenance covenants. However, our indentures are generally subject to cross-default provisions ranging from uncured payment defaults of $5.0 million to $50.0 million, and limitations on the incurrence of liens on our assets, generally exempting liens on utility assets, purchase money security interests, preexisting security interests and an additional subset of assets capped at 10% of our consolidated net tangible assets.

9. Property, Plant and Equipment

Our property, plant and equipment on the Consolidated Balance Sheets are classified as follows:

At December 31, *(in millions)*		**2024**		2023
Property, Plant and Equipment				
Gas Distribution Utility	**$**	**20,007.2**	$	18,154.5
Electric Utility		**8,666.8**		7,907.9
Corporate		**248.1**		274.2
Construction Work in Process		**2,084.7**		1,261.1
JV Renewable Generation Assets[(1)]		**1,434.2**		1,434.4
Non-Utility and Other		**1,711.9**		1,450.0
Total Property, Plant and Equipment	**$**	**34,152.9**	$	30,482.1
Accumulated Depreciation and Amortization				
Gas Distribution Utility	**$**	**(4,166.8)**	$	(3,924.4)
Electric Utility		**(2,707.8)**		(2,709.5)
Corporate		**(163.4)**		(174.2)
JV Renewable Generation Assets[(1)]		**(110.4)**		(64.5)
Non-Utility and Other		**(1,550.6)**		(1,334.6)
Total Accumulated Depreciation and Amortization	**$**	**(8,699.0)**	$	(8,207.2)
Net Property, Plant and Equipment	**$**	**25,453.9**	$	22,274.9

[(1)]These JV renewable generation assets owned and operated by JVs between NIPSCO and unrelated tax equity partners represent Non-Utility Property, are depreciated straight-line over 30 years and are part of our NIPSCO Operations segment. Refer to Note 4, "Noncontrolling Interests," for additional information.

The weighted average depreciation provisions for utility plant, as a percentage of the original cost, for the periods ended December 31, 2024, 2023 and 2022 were as follows:

	2024	2023	2022
NIPSCO Operations	**3.0 %**	3.0 %	2.7 %
Columbia Operations	**2.6 %**	2.5 %	2.4 %

We recognized depreciation expense of $820.4 million, $756.9 million and $685.0 million for the years ended 2024, 2023 and 2022, respectively. The 2024, 2023 and 2022, depreciation expense includes $58.9 million, $12.5 million, and $11.0 million

related to the regulatory deferral of income associated with our JVs. See Note 1, "Nature of Operations and Summary of Significant Accounting Policies - S. Noncontrolling Interest," for additional details.

Amortization of on-premise Software Costs. We amortized $85.2 million, $77.5 million and $53.1 million in 2024, 2023 and 2022, respectively, related to software recorded as intangible assets. Our unamortized software balance was $236.1 million and $205.6 million at December 31, 2024 and 2023, respectively.

Amortization of Cloud Computing Costs. We amortized $17.7 million, $12.6 million and $11.1 million in 2024, 2023 and 2022, respectively, related to cloud computing costs to "Operation and maintenance" expense. Our unamortized cloud computing balance was $77.5 million and $32.2 million at December 31, 2024 and 2023, respectively.

10. Goodwill

Substantially all of our goodwill relates to the excess of cost over the fair value of the net assets acquired in the Columbia acquisition on November 1, 2000. Our goodwill balance was $1,485.9 million as of December 31, 2024 and 2023. The majority of our goodwill has been allocated to the Columbia Operations segment.

For our annual goodwill impairment analysis performed as of May 1, 2024, we completed a quantitative ("step 1") fair value measurement of our reporting units. Fair value of our reporting units was determined based on a weighting of income and market approaches. The income approach calculated discounted cash flows using updated cash flow projections, discount rates and return on equity assumptions. The market approach applied a combination of comparable company multiples and comparable transactions and used the most recent cash flow projections. The test indicated that the fair value of each of the reporting units that are allocated goodwill exceeded their carrying values, indicating that no impairment was necessary.

11. Asset Retirement Obligations

We have recognized asset retirement obligations associated with various legal obligations including costs to remove and dispose of certain construction materials located within many of our facilities (including our JV facilities), certain costs to retire pipeline, removal costs for certain underground storage tanks, removal of certain pipelines known to contain PCB contamination, closure costs for certain sites including ash ponds, solid waste management units and a landfill, as well as some other nominal asset retirement obligations. We also have an obligation associated with the decommissioning of our two hydro facilities located in Indiana. These hydro facilities have an indeterminate life, and as such, no asset retirement obligation has been recorded.

During the fourth quarter of 2024, we continued to evaluate the applicability of revisions to the EPA rule for disposal of CCRs, which was announced in May 2024. As a result, we recorded an increase of $149.7 million based on initial assessments of estimated costs to comply with the EPA rule for certain sites. Additional costs will be recorded if they become probable and estimable. These costs are expected to be recoverable through existing and future depreciation rates. See Note 19, "Other Commitments and Contingencies - D. Environmental Matters," for additional information on the legacy CCR rule.

Changes in our liability for asset retirement obligations for the years 2024 and 2023 are presented in the table below:

(in millions)		**2024**		2023
Beginning Balance	**$**	**553.0**	$	513.5
Accretion recorded as a regulatory asset/liability		**25.3**		20.0
Additions		**189.9**		23.5
Settlements		**(72.5)**		(41.6)
Change in estimated cash flows		**87.5**		37.6
Ending Balance	**$**	**783.2**	$	553.0

Certain non-legal costs of removal not yet incurred but have been, and continue to be, included in depreciation rates and collected in the customer rates of the rate-regulated subsidiaries are classified as "Regulatory liabilities" on the Consolidated Balance Sheets.

12. Regulatory Matters

Regulatory Assets and Liabilities

We follow the accounting and reporting requirements of ASC Topic 980, which provides that regulated entities account for and report assets and liabilities consistent with the economic effect of regulatory rate-making procedures when the rates established are designed to recover the costs of providing the regulated service and it is probable that such rates will be charged and collected from customers. Certain expenses and credits subject to utility regulation or rate determination normally reflected in income or expense are deferred on the balance sheet and are recognized in the income statement as the related amounts are included in customer rates and recovered from or refunded to customers. We assess the probability of collection for all of our regulatory assets each period.

Regulatory assets were comprised of the following items:

At December 31, *(in millions)*	2024	2023
Regulatory Assets		
Unrecognized pension and other postretirement benefit costs (see Note 16)	**$ 485.3**	$ 561.6
Deferred pension and other postretirement benefit costs (see Note 16)	**45.3**	59.7
Environmental costs (see Note 19-D.)	**42.8**	40.6
Regulatory effects of accounting for income taxes (see Note 1-N. and Note 15)	**172.0**	163.5
Under-recovered gas and fuel costs (see Note 1-J.)	**82.3**	12.7
Depreciation	**214.9**	201.9
Post-in-service carrying charges	**280.8**	269.9
Safety activity costs	**203.7**	206.6
DSM programs	**17.8**	25.0
Retired coal generating stations	**617.0**	682.0
Losses on commodity price risk programs (See Note 13)	**6.5**	24.4
Deferred property taxes	**75.9**	72.3
Renewable energy investments	**81.3**	60.8
WAM system filing	**21.5**	—
Customer assistance programs	**24.4**	—
Other	**105.8**	79.2
Total Regulatory Assets	**$ 2,477.3**	$ 2,460.2
Less: Current Portion	**319.9**	214.3
Total Noncurrent Regulatory Assets	**$ 2,157.4**	$ 2,245.9

Regulatory liabilities were comprised of the following items:

At December 31, *(in millions)*	2024	2023
Regulatory Liabilities		
Over-recovered gas and fuel costs (see Note 1-J.)	**$ 21.4**	$ 144.5
Cost of removal (see Note 11)	**482.8**	597.2
Regulatory effects of accounting for income taxes (see Note 1-N. and Note 15)	**827.0**	849.9
Deferred pension and other postretirement benefit costs (see Note 16)	**40.4**	54.0
Gains on commodity price risk programs (See Note 13)	**28.7**	23.3
Customer assistance programs	**9.4**	19.8
Off-system sales sharing	**21.4**	19.0
Renewable energy investments (See Note 1-S. and Note 4)	**77.0**	18.1
Rate refunds	**16.6**	16.1
Other	**57.0**	47.4
Total Regulatory Liabilities	**$ 1,581.7**	$ 1,789.3
Less: Current Portion	**150.5**	278.6
Total Noncurrent Regulatory Liabilities	**$ 1,431.2**	$ 1,510.7

Regulatory assets, including under-recovered gas and fuel costs and depreciation, of approximately $671.3 million and $716.4 million as of December 31, 2024 and 2023, respectively, are not earning a return on investment. These costs are recovered over a remaining life of between 15 and 75 years.

Assets:

Unrecognized pension and other postretirement benefit costs. Represents the deferred other comprehensive income or loss of the actuarial gains or losses and the prior service costs or credits that arise during the period but that are not immediately recognized as components of net periodic benefit costs by certain subsidiaries that will ultimately be recovered through base rates.

Deferred pension and other postretirement benefit costs. Primarily relates to the difference between defined benefit plan expense recorded by certain subsidiaries due to regulatory orders and the corresponding expense that would otherwise be recorded in accordance with GAAP. This balance is driven by Columbia of Ohio deferrals.

Environmental costs. Includes certain recoverable costs related to gas plant sites, disposal sites or other sites onto which material may have migrated, the recovery of which is to be addressed in future base rates, billing riders or tracking mechanisms of certain of our subsidiaries.

Regulatory effects of accounting for income taxes. Represents the deferral and under collection of deferred taxes in the rate making process.

Under-recovered gas and fuel costs. Represents the difference between the costs of gas and fuel, as well as energy acquired through power purchase agreements, including NIPSCO's own renewable projects, and the recovery of such costs in revenue and is used to adjust future billings for such deferrals on a basis consistent with applicable state-approved tariff provisions. Recovery of these costs is achieved through tracking mechanisms.

Depreciation. Represents differences between depreciation expense incurred on a GAAP basis and that prescribed through regulatory order. The majority of this balance is driven by Columbia of Ohio's IRP and CEP deferrals.

Post-in-service carrying charges. Represents deferred debt-based carrying charges incurred on certain assets placed into service but not yet included in customer rates. The majority of this balance is driven by Columbia of Ohio's IRP and CEP deferrals.

Safety activity costs. Represents the difference between costs incurred by certain of our subsidiaries in eligible safety programs in compliance with PHMSA regulations in excess of those being recovered in rates. The majority of this balance is driven by Columbia of Ohio, which began recovery in March 2023 through base rates.

DSM programs. Represents costs associated with Columbia Operations and NIPSCO Operations energy efficiency and conservation programs. Costs are recovered through tracking mechanisms.

Retired coal generating stations. Represents the net book value of Units 7 and 8 of Bailly Generating Station that was retired during 2018 and the net book value of Units 14 and 15 of R.M. Schahfer Generating Station retired in 2021. These amounts are currently being amortized at a rate consistent with their inclusion in customer rates. The August 2023 NIPSCO electric rate case order extends the recovery of, and on, the net book value of the stations by the end of 2034 and implements a revenue credit for the retired units. The credit is based on the difference between the year-end value of Units 14 and 15 and the most recent value established in the last base rate case proceeding or credit compliance filing.

Losses on commodity price risk programs. Represents the unrealized losses related to certain of our subsidiary's commodity price risk programs. These programs help to protect against the volatility of commodity prices and these amounts are collected from customers through their inclusion in customer rates.

Deferred property taxes. Represents the deferral and under collection of property taxes in the rate making process for Columbia of Ohio and is driven by the IRP and CEP deferrals.

Renewable energy investments. Represents the regulatory deferral of renewable energy formation and developer costs.

WAM system filing. Represents the deferral of certain costs, including depreciation and amortization incurred in connection with improvements to its information technology systems through the design, development, and implementation of a new WAM program for the scheduling, dispatch, and execution of work and the management of underlying assets.

Customer Assistance Programs. Represents the difference between the eligible customer assistance program costs and collections, which will be collected from customers.

Liabilities:

Over-recovered gas and fuel costs. Represents the difference between the cost of gas and fuel, as well as energy acquired through power purchase agreements, including NIPSCO's own renewable projects and, the recovery of such costs in revenues and is the basis to adjust future billings for such refunds on a basis consistent with applicable state-approved tariff provisions. Refunding of these revenues is achieved through tracking mechanisms.

Cost of removal. Represents anticipated costs of removal for utility assets that have been collected through depreciation rates for future costs to be incurred.

Regulatory effects of accounting for income taxes. Represents amounts owed to customers for deferred taxes collected at a higher rate than the current statutory rates and liabilities associated with accelerated tax deductions owed to customers. Balance includes excess deferred taxes recorded upon implementation of the TCJA in December 2017, net of amounts amortized through 2024 and federal tax credits generated by Cavalry solar facility that are passed back to customers. For discussion of the regulatory impact of the NIPSCO Minority Interest Transaction on deferred taxes, see Note 15, "Income Taxes," for additional details.

Deferred pension and other postretirement benefit costs. Primarily represents cash contributions in excess of postretirement benefit expense that is deferred by certain subsidiaries.

Gains on commodity price risk programs. Represents the unrealized gains related to certain of our subsidiary's commodity price risk programs. These programs help to protect against the volatility of commodity prices, and these amounts are passed back to customers through their inclusion in customer rates.

Customer Assistance Programs. Represents the difference between the eligible customer assistance program costs and collections, which will be refunded to customers.

Renewable energy investments. Represents the regulatory deferral of certain amounts representing the timing difference between the profit earned from the JVs and the amount included in regulated rates to recover our approved investments in consolidated JVs. The offset to the regulatory liability associated with our renewable investments is recorded in "Depreciation expense" on the Statements of Consolidated Comprehensive Income. Refer to Note 1, "Nature of Operations and Summary of Significant Accounting Policies - S. Noncontrolling Interest," Note 4, "Noncontrolling Interests," and Note 9, "Property, Plant and Equipment," for additional information.

Rate Refunds. Represents supplier refunds received by the company that are owed to customers and will be remitted and amounts that are being collected in rates subject to refund.

Off System Sales Sharing. Represents amounts to be passed back to the customers as a result of Off System sales that is shared between the company and the customer.

Regulatory Filings

Renewable generation filings

In March 2024, NIPSCO filed a petition with the IURC to issue an order modifying its November 22, 2023 order to approve direct ownership of the Gibson project. Also, in March 2024, NIPSCO filed a petition with the IURC to issue an order modifying its June 29, 2021 order to approve direct ownership of the Fairbanks project. Hearings for both the Gibson project and Fairbanks project were held in June 2024 and July 2024, respectively, with orders approving direct ownership of both projects received in August 2024.

NIPSCO Gas peaker filing

In September 2023, NIPSCO filed a request for issuance of a CPCN for an approximately 400 MW natural gas peaking generation facility with the IURC, which was supplemented in January 2024 based on updates on availability of certain key equipment. A final order was received in October 2024 approving the request.

NIPSCO Electric rate case filing
On February 7, 2025, NIPSCO and certain intervening parties filed a Joint Stipulation and Settlement Agreement with the IURC. New rates proposed to be implemented in 2 steps, with implementation of Step 1 rates effective no later than September 2025 and Step 2 rates to be effective no later than March 2026.

Columbia of Virginia rate case filing
Columbia of Virginia and the intervening parties, with the exception of the Office of the Attorney General, filed a Joint Stipulation and Proposed Recommendation for settlement on December 5, 2024 for an annual revenue increase of $28.2 million, net of SAVE. Rates became effective on an as filed basis in October 2024 and we have recorded a regulatory liability to reflect the pending settlement.

13. Risk Management Activities

We are exposed to certain risks related to our ongoing business operations; namely commodity price risk and interest rate risk. We recognize that the prudent and selective use of derivatives may help to limit volatility in the price of natural gas, and manage interest rate exposure.

Risk management assets and liabilities on our derivatives are presented on the Consolidated Balance Sheets as shown below:

	December 31, 2024		December 31, 2023	
(in millions)	**Assets**	**Liabilities**	**Assets**	**Liabilities**
Current[1]				
Derivatives not designated as hedging instruments	**$ 9.1**	**$ 2.3**	$ 1.1	$ 7.5
Total	**$ 9.1**	**$ 2.3**	$ 1.1	$ 7.5
Noncurrent[2]				
Derivatives not designated as hedging instruments	**$ 17.9**	**$ 1.2**	$ 22.2	$ 1.9
Total	**$ 17.9**	**$ 1.2**	$ 22.2	$ 1.9

[1] Current assets and liabilities are presented in "Prepayments and other" and "Other accruals", respectively, on the Consolidated Balance Sheets.
[2] Noncurrent assets and liabilities are presented in "Deferred charges and other" and "Other noncurrent liabilities and deferred credits", respectively, on the Consolidated Balance Sheets.

Our derivative instruments are subject to enforceable master netting arrangements or similar agreements. No collateral was either received or posted related to our outstanding derivative positions at December 31, 2024 and 2023. If the above gross asset and liability positions were presented net of amounts owed or receivable from counterparties, we would report a net asset position of $23.5 million and $13.9 million at December 31, 2024 and 2023, respectively.

Derivatives Not Designated as Hedging Instruments
C***ommodity price risk management.*** We, along with our utility customers, are exposed to variability in cash flows associated with natural gas purchases and volatility in natural gas prices. We purchase natural gas for sale and delivery to our retail, commercial and industrial customers, and for most customers the variability in the market price of gas is passed through in their rates. Some of our utility subsidiaries offer programs whereby variability in the market price of gas is assumed by the respective utility. The objective of our commodity price risk programs is to mitigate the gas cost variability, for us or on behalf of our customers, associated with natural gas purchases or sales by economically hedging the various gas cost components using a combination of futures, options, forwards or other derivative contracts. As of December 31, 2024 and 2023, we had 77.8 MMDth and 76.1 MMDth, respectively, of net energy derivative volumes outstanding related to our natural gas hedges.

NIPSCO has received IURC approval to lock in a fixed price for its natural gas customers using long-term forward purchase instruments and is limited to 20% of NIPSCO's average annual GCA purchase volume. As of December 31, 2024, the remaining terms of these instruments range from one to three years. Likewise, Columbia of Pennsylvania has received approval for a 24-month rolling hedge program. The hedging program was executed in December 2023, with an effective date of April 1, 2024 and will continue in perpetuity. The program is designed to financially hedge approximately 20% of the customer's annual demand. All gains and losses on these derivative contracts are deferred as regulatory liabilities or assets and are remitted to or collected from customers through the relevant cost recovery mechanism.

Derivatives Designated as Hedging Instruments

Interest rate risk management. As of December 31, 2024 and 2023, we had no forward-starting interest rate swaps outstanding.

The overall net loss related to our multiple settled interest rate swaps is recorded to AOCI. We amortize the net loss over the life of the debt associated with these swaps as we recognize interest expense. These amounts are immaterial in 2024, 2023 and 2022 and are recorded in "Interest expense, net" on the Statements of Consolidated Income.

Cash flows for derivative financial instruments are generally classified as operating activities.

14. Fair Value

A. Fair Value Measurements

Recurring Fair Value Measurements

The following tables present financial assets and liabilities measured and recorded at fair value on our Consolidated Balance Sheets on a recurring basis and their level within the fair value hierarchy as of December 31, 2024 and December 31, 2023:

Recurring Fair Value Measurements December 31, 2024 (*in millions*)	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance as of December 31, 2024
Assets				
U.S. Treasury debt securities[(1)]	$ 80.1	$ —	$ —	$ 80.1
Risk management assets	—	27.0	—	27.0
Available-for-sale debt securities	—	86.7	—	86.7
Total	**$ 80.1**	**$ 113.7**	**$ —**	**$ 193.8**
Liabilities				
Risk management liabilities	$ —	$ 3.5	$ —	$ 3.5
Total	**$ —**	**$ 3.5**	**$ —**	**$ 3.5**

[(1)] Treasury bills are presented in "Cash and cash equivalents" and "Restricted cash" on the Consolidated Balance Sheets.

Recurring Fair Value Measurements December 31, 2023 (*in millions*)	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance as of December 31, 2023
Assets				
Risk management assets	$ —	$ 23.3	$ —	$ 23.3
Available-for-sale debt securities	—	159.1	—	159.1
Total	**$ —**	**$ 182.4**	**$ —**	**$ 182.4**
Liabilities				
Risk management liabilities	$ —	$ 9.4	$ —	$ 9.4
Total	**$ —**	**$ 9.4**	**$ —**	**$ 9.4**

Risk Management Assets and Liabilities. Risk management assets and liabilities include interest rate swaps, exchange-traded NYMEX futures and NYMEX options and non-exchange-based forward purchase contracts.

Level 1- When utilized, exchange-traded derivative contracts are based on unadjusted quoted prices in active markets and are classified within Level 1. These financial assets and liabilities are secured with cash on deposit with the exchange; therefore, nonperformance risk has not been incorporated into these valuations. These financial assets and liabilities are deemed to be cleared and settled daily by NYMEX as the related cash collateral is posted with the exchange. As a result of this exchange rule, NYMEX derivatives are considered to have no fair value at the balance sheet date for financial reporting purposes, and are presented in Level 1 net of posted cash; however, the derivatives remain outstanding and are subject to future commodity price fluctuations until they are settled in accordance with their contractual terms.

Level 2- Certain non-exchange-traded derivatives are valued using broker or over-the-counter, on-line exchanges. In such cases, these non-exchange-traded derivatives are classified within Level 2. Non-exchange-based derivative instruments include swaps, forwards, and options. In certain instances, these instruments may utilize models to measure fair value. We use a similar model to value similar instruments. Valuation models utilize various inputs that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in markets that are not active, other observable inputs for the asset or liability and market-corroborated inputs, (i.e., inputs derived principally from or corroborated by observable market data by correlation or other means). Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized within Level 2.

Level 3- Certain derivatives trade in less active markets with a lower availability of pricing information and models may be utilized in the valuation. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized within Level 3.

Credit risk is considered in the fair value calculation of derivative instruments that are not exchange-traded. Credit exposures are adjusted to reflect collateral agreements that reduce exposures. As of December 31, 2024 and 2023, there were no material transfers between fair value hierarchies. Additionally, there were no changes in the method or significant assumptions used to estimate the fair value of our financial instruments.

NIPSCO and Columbia of Pennsylvania have entered into long-term forward natural gas purchase instruments to lock in a fixed price for their natural gas customers. We value these contracts using a pricing model that incorporates market-based information when available, as these instruments trade less frequently and are classified within Level 2 of the fair value hierarchy. For additional information, see Note 13, “Risk Management Activities.”

Available-for-Sale Debt Securities. Available-for-sale debt securities are investments pledged as collateral for trust accounts related to our wholly-owned insurance company. We value U.S. Treasury, corporate debt and mortgage-backed securities using a matrix pricing model that incorporates market-based information. These securities trade less frequently and are classified within Level 2.

Our available-for-sale debt securities impairments are recognized periodically using an allowance approach. At each reporting date, we utilize a quantitative and qualitative review process to assess the impairment of available-for-sale debt securities at the individual security level. For securities in a loss position, we evaluate our intent to sell or whether it is more-likely-than-not that we will be required to sell the security prior to the recovery of its amortized cost. If either criteria is met, the loss is recognized in earnings immediately, with the offsetting entry to the carrying value of the security. If both criteria are not met, we perform an analysis to determine whether the unrealized loss is related to credit factors. The analysis focuses on a variety of factors that include, but are not limited to, downgrade on ratings of the security, defaults in the current reporting period or projected defaults in the future, the security's yield spread over treasuries, and other relevant market data. If the unrealized loss is not related to credit factors, it is included in other comprehensive income. If the unrealized loss is related to credit factors, the loss is recognized as credit loss expense in earnings during the period, with an offsetting entry to the allowance for credit losses. The amount of the credit loss recorded to the allowance account is limited by the amount at which the security's fair value is less than its amortized cost basis. If certain amounts recorded in the allowance for credit losses are deemed uncollectible, the allowance on the uncollectible portion will be charged off, with an offsetting entry to the carrying value of the security. Subsequent improvements to the estimated credit losses of available-for-sale debt securities will be recognized immediately in earnings. As of December 31, 2024 and December 31, 2023, we recorded $0.1 million and $0.6 million, respectively, as an allowance for credit losses on available-for-sale debt securities as a result of the analysis described above. Continuous credit monitoring and portfolio credit balancing mitigates our risk of credit losses on our available-for-sale debt securities.

The amortized cost, gross unrealized gains and losses, allowance for credit losses, and fair value of available-for-sale securities at December 31, 2024 and 2023 were:

December 31, 2024 *(in millions)*	Amortized Cost	Gross Unrealized Gains	Gross Unrealized Losses[1]	Allowance for Credit Losses	Fair Value
Available-for-sale debt securities					
Corporate/Other debt securities	$ 91.9	$ 0.5	$ (5.6)	$ (0.1)	$ 86.7
Total	**$ 91.9**	**$ 0.5**	**$ (5.6)**	**$ (0.1)**	**$ 86.7**

December 31, 2023 *(in millions)*	Amortized Cost	Gross Unrealized Gains	Gross Unrealized Losses[2]	Allowance for Credit Losses	Fair Value
Available-for-sale debt securities					
U.S. Treasury debt securities	$ 63.8	$ —	$ (3.2)	$ —	$ 60.6
Corporate/Other debt securities	105.2	0.8	(6.9)	(0.6)	98.5
Total	**$ 169.0**	**$ 0.8**	**$ (10.1)**	**$ (0.6)**	**$ 159.1**

[1] Fair value of Corporate/Other debt securities in an unrealized loss position without an allowance for credit losses is $70.1 million at December 31, 2024.
[2] Fair value of U.S. Treasury debt securities and Corporate/Other debt securities in an unrealized loss position without an allowance for credit losses is $58.7 million and $74.8 million, respectively, at December 31, 2023.

Realized gains and losses on available-for-sale securities was $2.3 million for the year ended December 31, 2024 and $1.0 million for 2023.

The cost of maturities sold is based upon specific identification. At December 31, 2024, approximately $10.9 million of Corporate/Other debt securities have maturities of less than a year.

There are no material items in the fair value reconciliation of Level 3 assets and liabilities measured at fair value on a recurring basis for the years ended December 31, 2024 and 2023.

Additional plan investments in corporate-owned life insurance are recorded at their cash surrender value, not fair value, and therefore are not included above. These plan investments are classified as "Other investments" on the Consolidated Balance Sheets.

Non-recurring Fair Value Measurements

We measure the fair value of certain assets, including goodwill, on a non-recurring basis, typically when events or changes in circumstances indicate that the carrying amount of the assets may not be recoverable.

B. Other Fair Value Disclosures for Financial Instruments. The carrying amount of cash and cash equivalents, restricted cash, notes receivable, customer deposits and short-term borrowings is a reasonable estimate of fair value due to their liquid or short-term nature. Our long-term borrowings are recorded at historical amounts.

The following method and assumptions were used to estimate the fair value of each class of financial instruments.

Long-term debt. The fair value of outstanding long-term debt is estimated based on the quoted market prices for the same or similar securities. Certain premium costs associated with the early settlement of long-term debt are not taken into consideration in determining fair value. These fair value measurements are classified within Level 2 of the fair value hierarchy. For the years ended December 31, 2024 and 2023, there was no change in the method or significant assumptions used to estimate the fair value of long-term debt.

The carrying amount and estimated fair values of these financial instruments were as follows:

At December 31, *(in millions)*	**Carrying Amount 2024**	**Estimated Fair Value 2024**	Carrying Amount 2023	Estimated Fair Value 2023
Long-term debt (including current portion)	**$ 13,355.7**	**$ 12,505.2**	$ 11,079.3	$ 10,370.9

15. Income Taxes

Judgment and the use of estimates are required in developing the provision for income taxes and reporting of tax-related assets and liabilities. The interpretation of tax laws and associated regulations involves uncertainty as taxing authorities may interpret the laws differently.

NIPSCO's historical business activities through the closing of the NIPSCO Minority Interest Transaction in 2023 were included in the consolidated U.S. federal and certain state income tax returns of NiSource Inc. Historically, NIPSCO has been treated as a taxable division of its corporate parent, NiSource Inc., and then as a division of NIPSCO Holdings I effective April 13, 2023. In connection with the NIPSCO Minority Interest Transaction, NIPSCO Holdings I retained NIPSCO's income tax balances and 80.1% of the excess deferred income tax regulatory balances as described below. NIPSCO Holdings I's income tax balances are based on the difference between the financial statement amount and the tax basis of its investment in NIPSCO Holdings II.

Income Tax Expense. The components of income tax expense (benefit) were as follows:

Year Ended December 31, *(in millions)*	**2024**	2023	2022
Income Taxes			
Current			
Federal	**$ (19.3)**	$ —	$ 0.4
State	**9.4**	5.3	7.3
Total Current (Benefit) Expense	**(9.9)**	5.3	7.7
Deferred			
Federal			
Taxes before operating loss carryforwards and investment credits	**105.9**	49.7	87.9
Tax utilization expense of operating loss carryforwards	**60.4**	65.1	93.1
Investment tax credits	**(0.1)**	(2.1)	—
State	**2.6**	22.5	(23.0)
Total Deferred Expense	**168.8**	135.2	158.0
Deferred Investment Tax Credits	**(0.8)**	(1.0)	(1.1)
Income Taxes from Continuing Operations	**$ 158.1**	$ 139.5	$ 164.6

In connection with the NIPSCO Minority Interest Transaction during 2023, NiSource recognized a $63.5 million income tax benefit in additional paid in capital related to 19.9% of NIPSCO's excess deferred income taxes attributable to Blackstone's noncontrolling interest. This benefit does not impact NIPSCO's regulatory books or the excess deferred taxes that will benefit customers through lower future rates in accordance with applicable regulatory orders. See Note 4, "Noncontrolling Interests," for further discussion of the NIPSCO Minority Interest Transaction.

Statutory Rate Reconciliation. The following table represents a reconciliation of income tax expense at the statutory federal income tax rate to the actual income tax expense from continuing operations:

Year Ended December 31, *(in millions)*	**2024**		2023		2022	
Book income before income taxes	**$ 1,002.8**		$ 813.9		$ 956.4	
Tax expense at statutory federal income tax rate	**210.6**	**21.0 %**	170.8	21.0 %	200.8	21.0 %
Increases (reductions) in taxes resulting from:						
State income taxes, net of federal income tax benefit	**11.7**	**1.2**	13.7	1.7	4.5	0.5
Amortization of regulatory liabilities	**(11.1)**	**(1.1)**	(38.2)	(4.7)	(38.5)	(4.0)
Employee stock ownership plan dividends and other compensation	**(1.3)**	**(0.1)**	(1.3)	(0.2)	(1.2)	(0.1)
Federal tax credits	**(23.3)**	**(2.3)**	(4.9)	(0.6)	(2.3)	(0.2)
Tax effect of non-controlling Interest	**(27.3)**	**(2.7)**	—	—	—	—
Other adjustments	**(1.2)**	**(0.2)**	(0.6)	(0.1)	1.3	—
Income Taxes	**$ 158.1**	**15.8 %**	$ 139.5	17.1 %	$ 164.6	17.2 %

The increase in tax expense of $18.6 million in 2024 versus 2023 was primarily due to higher pre-tax income, partially offset by the tax effect of non-controlling interest, and higher federal tax credits generated by the Cavalry solar and storage facility that are offset in a regulatory liability to pass back to customers in future periods.

The decrease in the Amortization of Regulatory Liabilities in 2024 versus 2023 was primarily due to the regulatory liability established for the Cavalry tax credits generated in 2024, net of TCJA excess deferred amortization which decreased approximately $7.9 million from the prior year.

The difference in tax expense of $25.1 million in 2023 versus 2022 was primarily due to lower pre-tax income.

Net Deferred Income Tax Liability Components. Deferred income taxes result from temporary differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities. The principal components of our net deferred tax liabilities were as follows:

At December 31, *(in millions)*	**2024**	2023
Deferred tax liabilities		
Accelerated depreciation and other property differences	**$ 1,419.4**	$ 1,384.8
Partnership basis differences	**1,328.6**	1,241.9
Other regulatory assets	**210.1**	212.1
Total Deferred Tax Liabilities	**2,958.1**	2,838.8
Deferred tax assets		
Other regulatory liabilities and deferred investment tax credits (including TCJA)	**170.4**	182.2
Pension and other postretirement/postemployment benefits	**58.8**	58.6
Loss and credit carryforwards	**369.4**	422.9
Environmental liabilities	**12.2**	10.1
Other accrued liabilities	**43.4**	40.3
Other, net	**28.7**	50.7
Total Deferred Tax Assets	**682.9**	764.8
Valuation Allowance	**(6.4)**	(6.4)
Net Deferred Tax Assets	**676.5**	758.4
Net Deferred Tax Liabilities	**$ 2,281.6**	$ 2,080.4

In connection with the NIPSCO Minority Interest Transaction, NIPSCO's deferred taxes were removed from its GAAP books and were reconstituted as deferred taxes on the outside basis difference of NiSource's investment in NIPSCO Holdings II. These deferred taxes are reflected as partnership basis differences above.

NiSource has the following deductible loss and credit carryforwards:

At December 31, 2024 *(in millions)*	**Deductible Amount**	**Deferred Tax Asset**	**Valuation Allowance**	**Expiration Period**
Federal losses	$ 1,369.1	$ 287.5	$ —	2037
Federal investment tax credits	—	2.2	—	2043
Federal production tax credits	—	1.0	—	2040-2043
Federal other credit	—	17.3	—	2029-2043
State losses	2,024.4	81.9	(6.4)	2031-2037
Total		**$ 389.9**	**$ (6.4)**	

We believe it is not more likely than not that a portion of the benefit from certain state net operating loss carryforwards will be realized. We have recorded a valuation allowance of $6.4 million on the deferred tax assets related to sale of Massachusetts Business assets reflected in the state net operating loss carryforward presented above.

Unrecognized Tax Benefits. A reconciliation of the beginning and ending amounts of unrecognized tax benefits is as follows:

At December 31, 2024*(in millions)*	**2024**	2023	2022
Opening Balance	**$ 21.7**	$ 21.7	$ 21.7
Gross decreases - tax positions in prior period	**—**	—	—
Gross increases - current period tax positions	**—**	—	—
Ending Balance	**$ 21.7**	$ 21.7	$ 21.7
Offset for net operating loss carryforwards	**(21.7)**	(21.7)	(21.7)
Balance, Less Net Operating Loss Carryforwards	**$ —**	$ —	$ —

We are subject to income taxation in the United States and various state jurisdictions, primarily Indiana, Pennsylvania, Kentucky, Massachusetts, Maryland and Virginia.

We participate in the IRS CAP, which provides the opportunity to resolve tax matters with the IRS before filing each year's consolidated federal income tax return. As of December 31, 2024, tax years through 2021 have been audited and are closed to further assessment. The Company has transitioned to the Bridge Phase of the IRS CAP for the year ended December 31, 2022 and participated in the Bridge Plus pilot program in 2022 and 2023. NiSource received a full acceptance letter from the IRS for its 2022 return, but has not yet received a final acceptance letter from the IRS for its 2023 return. However, no adjustments are expected, and the year is effectively closed to further assessment.

The statute of limitations in each of the state jurisdictions in which we operate remains open between 3-4 years from the date the state income tax returns are filed. As of December 31, 2024, there were no state income tax audits in progress that would have a material impact on the consolidated financial statements.

NiSource is obligated to report adjustments resulting from IRS audits or settlements to state taxing authorities. In addition, if NiSource utilizes net operating losses or tax credits generated in years for which the statute of limitations has expired, such amounts are generally subject to examination.

On April 14, 2023, the IRS issued Revenue Procedure 2023-15 which provides a safe harbor method of accounting that taxpayers may use to determine whether expenses to repair, maintain, replace, or improve linear property and non-linear natural gas transmission and distribution property must be capitalized as improvements or are allowable as deductions. On June 3, 2024, the IRS extended the favorable rules to a Year 2 adoption period. The Company is planning to elect this change in tax accounting method with its 2024 consolidated tax return filing in the upcoming year and continues to analyze and quantify the provisions of the safe harbor method of accounting.

16. Pension and Other Postemployment Benefits

We provide defined contribution plans and noncontributory defined benefit retirement plans that cover certain of our employees. Benefits under the defined benefit retirement plans reflect the employees' compensation, years of service and age at retirement. Additionally, we provide health care and life insurance benefits for certain retired employees. The majority of employees may become eligible for these benefits if they reach retirement age while working for us. The expected cost of such benefits is accrued during the employees' years of service. Current rates of rate-regulated companies include postretirement benefit costs, including amortization of the regulatory assets that arose prior to inclusion of these costs in rates. For most plans, cash contributions are remitted to grantor trusts.

Our Pension and Other Postretirement Benefit Plans' Asset Management. The Board has delegated oversight of the pension and other postretirement benefit plans' assets to the NiSource Benefits Committee (the "Committee"). The Committee has adopted investment policy statements for the pension and other postretirement benefit plans' assets. For the pension plans, we employ a liability-driven investing strategy. A total return approach is utilized for the other postretirement benefit plans' assets. A mix of diversified investments are used to maximize the long-term return of plan assets and hedge the liabilities at a prudent level of risk. The investment portfolio includes U.S. and non-U.S. equities, real estate, long-term and intermediate-term fixed income and alternative investments. Risk tolerance is established through careful consideration of plan liabilities, funded status, and asset class volatility. Investment risk is measured and monitored on an ongoing basis through quarterly investment portfolio reviews, annual liability measurements, and periodic asset/liability studies.

In determining the expected long-term rate of return on plan assets, historical markets are studied, relationships between equities and fixed income are analyzed and current market factors, such as inflation and interest rates are evaluated with consideration of diversification and rebalancing. Our expected long-term rate of return on assets is based on assumptions regarding target asset allocations and corresponding long-term capital market assumptions for each asset class. The pension plans' investment policy calls for a gradual reduction in the allocation of return-seeking assets (equities, real estate and private equity) and a corresponding increase in the allocation of liability-hedging assets (fixed income) as the funded status of the plans' increase.

As of December 31, 2024 and December 31, 2023, the acceptable minimum and maximum ranges established by the policy for the pension and other postretirement benefit plans are as follows:

December 31, 2024	Defined Benefit Pension Plan		Postretirement Benefit Plan	
Asset Category	Minimum	Maximum	Minimum	Maximum
Domestic Equities	10%	30%	0%	55%
International Equities	5%	15%	0%	25%
Fixed Income	65%	75%	20%	100%
Real Estate	0%	0%	0%	0%
Private Equity	0%	3%	0%	0%
Short-Term Investments	0%	10%	0%	10%

December 31, 2023	Defined Benefit Pension Plan		Postretirement Benefit Plan	
Asset Category	Minimum	Maximum	Minimum	Maximum
Domestic Equities	10%	30%	0%	55%
International Equities	5%	15%	0%	25%
Fixed Income	65%	75%	20%	100%
Real Estate	0%	0%	0%	0%
Private Equity	0%	3%	0%	0%
Short-Term Investments	0%	10%	0%	10%

The actual Pension Plan and Postretirement Plan Asset Mix at December 31, 2024 and December 31, 2023 are as follows:

	Defined Benefit Pension Assets[1]	December 31, 2024	Postretirement Benefit Plan Assets	December 31, 2024
Asset Class *(in millions)*	Asset Value	% of Total Assets	Asset Value	% of Total Assets
Domestic Equities	$ 258.9	19.4 %	$ 99.6	40.9 %
International Equities	122.5	9.2 %	40.7	16.7 %
Fixed Income	891.2	66.7 %	96.5	39.6 %
Real Estate	4.0	0.3 %	—	—
Cash/Other	59.8	4.4 %	6.7	2.8 %
Total	$ 1,336.4	100.0 %	$ 243.5	100.0 %

[1]Total includes accrued dividends and pending trades with brokers.

	Defined Benefit Pension Assets[1]	December 31, 2023	Postretirement Benefit Plan Assets[1]	December 31, 2023
Asset Class *(in millions)*	Asset Value	% of Total Assets	Asset Value	% of Total Assets
Domestic Equities	$ 261.7	18.3 %	$ 93.7	39.6 %
International Equities	141.9	9.9 %	40.7	17.2 %
Fixed Income	939.9	65.9 %	97.0	41.0 %
Real Estate	4.0	0.3 %	—	—
Cash/Other	79.3	5.6 %	5.1	2.2 %
Total	$ 1,426.8	100.0 %	$ 236.5	100.0 %

[1]Total includes accrued dividends and pending trades with brokers.

The categorization of investments into the asset classes in the tables above are based on definitions established by the Committee.

Fair Value Measurements. The following table sets forth, by level within the fair value hierarchy, the pension and other postretirement benefits investment assets at fair value as of December 31, 2024 and 2023. Assets are classified in their entirety based on the observability of inputs used in determining the fair value measurement. There were no material investment assets in the pension and other postretirement benefits trusts classified within Level 3 for the years ended December 31, 2024 and 2023.

We use the following valuation techniques to determine fair value. For the year ended December 31, 2024, there were no significant changes to valuation techniques to determine the fair value of our pension and other postretirement benefits' assets.

Level 1 Measurements
Most common and preferred stocks are traded in active markets on national and international securities exchanges and are valued at closing prices on the last business day of each period presented. Cash is stated at cost, which approximates fair value, with the exception of cash held in foreign currencies which fluctuates with changes in the exchange rates. Short-term bills and notes are priced based on quoted market values.

Level 2 Measurements
Most U.S. Government Agency obligations, mortgage/asset-backed securities, and corporate fixed income securities are generally valued by benchmarking model-derived prices to quoted market prices and trade data for identical or comparable securities. To the extent that quoted prices are not available, fair value is determined based on a valuation model that includes inputs such as interest rate yield curves and credit spreads. Securities traded in markets that are not considered active are valued based on quoted market prices, broker or dealer quotations, or alternative pricing sources with reasonable levels of price transparency. Other fixed income includes futures and options which are priced on bid valuation or settlement pricing.

Level 3 Measurements
Investments with unobservable inputs that are supported by little or no market activity and that are significant to the fair value of the assets and liabilities are classified as level 3 investments.

Not Classified
Commingled funds, private equity limited partnerships and real estate partnerships are not classified within the fair value hierarchy. Instead, these assets are measured at estimated fair value using the net asset value per share of the investments. Commingled funds' underlying assets are principally marketable equity and fixed income securities. Units held in commingled funds are valued at the unit value as reported by the investment managers. Private equity funds invest capital in non-public companies and real estate funds invest in commercial and distressed real estate directly or through related debt instruments. The fair value of these investments is determined by reference to the funds' underlying assets.

Fair Value Measurements at December 31, 2024:

(in millions)	December 31, 2024	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Pension plan assets:				
Cash	$ 1.2	$ 1.1	$ 0.1	$ —
Fixed income securities				
Government	186.8	—	186.8	—
Corporate	486.6	—	486.6	—
Mortgages/ Asset Backed Securities	3.6	—	3.6	—
Mutual Funds				
U.S. multi-strategy	56.1	56.1	—	—
International equities	57.2	57.2	—	—
Private equity limited partnerships[1]				
U.S. multi-strategy[2]	3.1	—	—	—
International multi-strategy[3]	0.8	—	—	—
Distressed opportunities	0.1	—	—	—
Real estate[1]	4.0	—	—	—
Commingled funds[1]				
Short-term money markets	45.9	—	—	—
U.S. equities	202.8	—	—	—
International equities	65.3	—	—	—
Fixed income	214.1	—	—	—
Pension plan assets subtotal	$ 1,327.6	$ 114.4	$ 677.1	$ —
Other postretirement benefit plan assets:				
Mutual funds				
U.S. multi-strategy	87.4	87.4	—	—
International equities	16.5	16.5	—	—
Fixed income	96.5	96.5	—	—
Commingled funds[1]				
Short-term money markets	6.7	—	—	—
U.S. equities	12.2	—	—	—
International equities	24.2	—	—	—
Other postretirement benefit plan assets subtotal	$ 243.5	$ 200.4	$ —	$ —
Due to brokers, net[4]	(0.1)	—	(0.1)	—
Accrued income/dividends	8.9	8.9		—
Total pension and other postretirement benefit plan assets	$ 1,579.9	$ 323.7	$ 677.0	$ —

[1] This class of investments is measured at fair value using the net asset value per share and has not been classified in the fair value hierarchy.
[2] This class includes limited partnerships that invest in a diverse portfolio of private equity strategies, including buy-outs, growth capital, special situations and secondary markets, primarily inside the United States.
[3] This class includes limited partnerships that invest a in diverse portfolio of private equity strategies, including buy-outs, growth capital, special situations and secondary markets, primarily outside the United States.
[4] This class represents pending trades with brokers.

The table below sets forth a summary of unfunded commitments, redemption frequency and redemption notice periods for certain investments that are measured at fair value using the net asset value per share for the year ended December 31, 2024:

(in millions)	Fair Value	Redemption Frequency	Redemption Notice Period
Commingled Funds			
Short-term money markets	$ 52.6	Daily	1 day
U.S. equities	215.0	Daily	1 day - 5 days
International equities	89.5	Monthly	10 days-30 days
Fixed income	214.1	Daily	3 days
Private Equity and Real Estate Limited Partnerships[(1)]	8.0	N/A	N/A
Total	$ 579.2		

[(1)]Private equity and real estate limited partnerships typically call capital over a 3-5 year period and pay out distributions as the underlying investments are liquidated. The typical expected life of these limited partnerships is 0-15 years, and these investments typically cannot be redeemed prior to liquidation.

Fair Value Measurements at December 31, 2023:

(in millions)	December 31, 2023	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Pension plan assets:				
Cash	$ 2.2	$ 2.0	$ 0.2	$ —
Equity securities				
International equities	1.1	1.1	—	—
Fixed income securities				
Government	213.1	—	213.1	—
Corporate	482.2	—	482.2	—
Mortgages/Asset backed securities	2.4	—	2.4	—
Mutual Funds				
U.S. multi-strategy	113.1	113.1	—	—
International equities	38.5	38.5	—	—
Private equity limited partnerships[1]				
U.S. multi-strategy[2]	4.8	—	—	—
International multi-strategy[3]	1.2	—	—	—
Distressed opportunities	0.1	—	—	—
Real estate[1]	4.0	—	—	—
Commingled funds[1]				
Short-term money markets	65.3	—	—	—
U.S. equities	148.5	—	—	—
International equities	102.3	—	—	—
Fixed income	242.2	—	—	—
Pension plan assets subtotal	$ 1,421.0	$ 154.7	$ 697.9	$ —
Other postretirement benefit plan assets:				
Mutual funds				
U.S. multi-strategy	82.4	82.4	—	—
International equities	18.0	18.0	—	—
Fixed income	97.0	97.0	—	—
Commingled funds[1]				
Short-term money markets	5.2	—	—	—
U.S. equities	11.4	—	—	—
International equities	22.8	—	—	—
Other postretirement benefit plan assets subtotal	$ 236.8	$ 197.4	$ —	$ —
Due to brokers, net[4]	(2.7)	—	(2.7)	—
Accrued income/dividends	8.5	8.5	—	—
Total pension and other postretirement benefit plan assets	$ 1,663.6	$ 360.6	$ 695.2	$ —

[1]This class of investments is measured at fair value using the net asset value per share and has not been classified in the fair value hierarchy.
[2]This class includes limited partnerships/fund of funds that invest in a diverse portfolio of private equity strategies, including buy-outs, growth capital, special situations and secondary markets, primarily inside the United States.
[3]This class includes limited partnerships/fund of funds that invest in diverse portfolio of private equity strategies, including buy-outs, growth capital, special situations and secondary markets, primarily outside the United States.
[4]This class represents pending trades with brokers.

The table below sets forth a summary of unfunded commitments, redemption frequency and redemption notice periods for certain investments that are measured at fair value using the net asset value per share for the year ended December 31, 2023:

(in millions)	Fair Value	Redemption Frequency	Redemption Notice Period
Commingled Funds			
Short-term money markets	$ 70.5	Daily	1 day
U.S. equities	159.9	Daily	1 day -5 days
International equities	125.1	Monthly	10 days - 30 days
Fixed income	242.2	Daily	3 days
Private Equity and Real Estate Limited Partnerships[(1)]	10.1	N/A	N/A
Total	$ 607.8		

[(1)]Private equity and real estate limited partnerships typically call capital over a 3-5 year period and pay out distributions as the underlying investments are liquidated. The typical expected life of these limited partnerships is 0-15 years, and these investments typically cannot be redeemed prior to liquidation.

Our Pension and Other Postretirement Benefit Plans' Funded Status and Related Disclosure. The following table provides a reconciliation of the plans' funded status and amounts reflected in our Consolidated Balance Sheets at December 31 based on a December 31 measurement date:

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2024**	2023	**2024**	2023
Change in projected benefit obligation[1]				
Benefit obligation at beginning of year	**$ 1,401.8**	$ 1,427.4	**$ 468.8**	$ 449.0
Service cost	**21.9**	20.5	**5.0**	5.1
Interest cost	**64.9**	68.4	**22.0**	21.8
Plan participants' contributions	**—**	—	**3.6**	4.2
Plan amendments	**—**	—	**—**	3.4
Actuarial loss (gain)[2]	**(64.8)**	27.4	**(22.5)**	29.1
Benefits paid	**(136.4)**	(141.9)	**(40.7)**	(44.3)
Estimated benefits paid by incurred subsidy	**—**	—	**0.1**	0.5
Projected benefit obligation at end of year	**$ 1,287.4**	$ 1,401.8	**$ 436.3**	$ 468.8
Change in plan assets				
Fair value of plan assets at beginning of year	**$ 1,426.8**	$ 1,422.8	**$ 236.5**	$ 224.9
Actual return on plan assets	**43.7**	142.8	**20.0**	28.2
Employer contributions	**2.4**	3.1	**23.6**	23.4
Plan participants' contributions	**—**	—	**3.8**	4.3
Benefits paid	**(136.4)**	(141.9)	**(40.7)**	(44.3)
Fair value of plan assets at end of year	**$ 1,336.5**	$ 1,426.8	**$ 243.2**	$ 236.5
Funded Status at end of year	**$ 49.1**	$ 25.0	**$ (193.1)**	$ (232.3)
Amounts recognized in the statement of financial position consist of:				
Noncurrent assets	**66.5**	44.1	**—**	—
Current liabilities	**(2.3)**	(2.2)	**(1.0)**	(1.0)
Noncurrent liabilities	**(15.1)**	(16.9)	**(192.1)**	(231.3)
Net amount recognized at end of year[3]	**$ 49.1**	$ 25.0	**$ (193.1)**	$ (232.3)
Amounts recognized in accumulated other comprehensive income or regulatory asset/liability[4]				
Unrecognized prior service credit	**$ 0.3**	$ 0.3	**$ 3.8**	$ 2.1
Unrecognized actuarial loss	**451.4**	500.4	**47.0**	76.6
Net amount recognized at end of year	**$ 451.7**	$ 500.7	**$ 50.8**	$ 78.7

[1]The change in benefit obligation for Pension Benefits represents the change in Projected Benefit Obligation while the change in benefit obligation for Other Postretirement Benefits represents the change in accumulated postretirement benefit obligation.
[2]The pension actuarial gain was primarily driven by the increase in discount rates interest rate movements. The postretirement benefit actuarial loss (gain) was also primarily driven by a increase in discount rates and claims experience changes in trend rates.
[3]We recognize our Consolidated Balance Sheets underfunded and overfunded status of our various defined benefit postretirement plans, measured as the difference between the fair value of the plan assets and the benefit obligation.
[4]We determined that for certain rate-regulated subsidiaries the future recovery of pension and other postretirement benefits costs is probable. These rate-regulated subsidiaries recorded regulatory assets and liabilities of $485.3 million and zero, respectively, as of December 31, 2024, and $561.6 million and zero, respectively, as of December 31, 2023 that would otherwise have been recorded to accumulated other comprehensive loss.

Our accumulated benefit obligation for our pension plans was $1,278.4 million and $1,390.9 million as of December 31, 2024 and 2023, respectively. The accumulated benefit obligation at each date is the actuarial present value of benefits attributed by the pension benefit formula to employee service rendered prior to that date and based on current and past compensation levels. The accumulated benefit obligation differs from the projected benefit obligation disclosed in the table above in that it includes no assumptions about future compensation levels.

We are required to reflect the funded status of our pension and postretirement benefit plans on the Consolidated Balance Sheet. The funded status of the plans is measured as the difference between the plan assets' fair value and the projected benefit obligation. We present the noncurrent aggregate of all underfunded plans within "Accrued liability for postretirement and postemployment benefits." The portion of the amount by which the actuarial present value of benefits included in the projected

benefit obligation exceeds the fair value of plan assets, payable in the next 12 months, is reflected in "Accrued compensation and other benefits." We present the aggregate of all overfunded plans within "Deferred charges and other."

For our pension plans as of December 31, 2024 and 2023, only our nonqualified plans were underfunded. These plans have no assets as they are not funded until benefits are paid. The following table sets forth the year end accumulated benefit obligation and projected benefit obligation for pension plans with a projected benefit obligation in excess of plan assets:

	December 31,	
	2024	2023
Accumulated Benefit Obligation	**$ 17.4**	$ 19.1
Funded Status		
Projected Benefit Obligation	**$ 17.4**	$ 19.1
Funded Status of Underfunded Pension Plans at End of Year	**$ (17.4)**	$ (19.1)

The following table sets forth the year end accumulated benefit obligation, projected benefit obligation and fair value of plan assets for pension plans with plan assets in excess of the projected benefit obligation:

	December 31,	
	2024	2023
Accumulated Benefit Obligation	**$ 1,261.0**	$ 1,371.8
Funded Status		
Fair Value of Plan Assets	**$ 1,336.4**	$ 1,426.8
Projected Benefit Obligation	**1,269.9**	1,382.7
Funded Status of Overfunded Pension Plans at End of Year	**$ 66.5**	$ 44.1

Our pension plans were overfunded, in aggregate, by $49.1 million at December 31, 2024 compared to being overfunded by $25.0 million at December 31, 2023. The improvement in the funded status was primarily due to an increase in discount rates partially offset by actual return on assets being less than expected return on assets. We contributed $2.4 million and $3.1 million to our pension plans in 2024 and 2023, respectively.

Our other postretirement benefit plans were underfunded, in aggregate by $193.1 million and $232.3 million at December 31, 2024 and 2023, respectively. The change in funded status was primarily due to increased discount rates and actual return on plan assets exceeding expected return. We contributed $23.6 million and $23.4 million to our other postretirement benefit plans in 2024 and 2023, respectively.

In 2024 and 2023, our NiSource Pension Restoration and Columbia Energy Group pension plans paid lump sum payouts in excess of the respective plan's service cost plus interest cost, thereby meeting the requirement for settlement accounting. We recorded settlement charges of $7.2 million and $9.2 million in 2024 and 2023, respectively. In 2024 and 2023, no remeasurement occurred related to lump sum payouts.

The following table provides the key assumptions that were used to calculate the pension and other postretirement benefits obligations for our various plans as of December 31:

	Pension Benefits		Other Postretirement Benefits	
	2024	2023	**2024**	2023
Weighted-average assumptions to Determine Benefit Obligation				
Discount Rate	**5.58 %**	4.95 %	**5.66 %**	4.98 %
Rate of Compensation Increases	**4.00 %**	4.00 %	**N/A**	N/A
Interest Crediting Rates	**4.00 %**	4.00 %	**N/A**	N/A
Health Care Trend Rates				
Trend for Next Year	**N/A**	N/A	**9.77 %**	8.84 %
Ultimate Trend	**N/A**	N/A	**4.75 %**	4.75 %
Year Ultimate Trend Reached	**N/A**	N/A	**2033**	2032

We expect to make contributions of approximately $2.3 million to our pension plans and approximately $21.3 million to our postretirement medical and life plans in 2025.

The following table provides benefits expected to be paid in each of the next five fiscal years, and in the aggregate for the five fiscal years thereafter. The expected benefits are estimated based on the same assumptions used to measure our benefit obligation at the end of the year and include benefits attributable to the estimated future service of employees:

(in millions)	Pension Benefits	Other Postretirement Benefits
Year(s)		
2025	$ 142.6	$ 36.6
2026	136.6	36.1
2027	130.9	36.1
2028	125.8	35.8
2029	119.4	35.6
2030-2034	528.6	171.7

The following table provides the components of the plans' actuarially determined net periodic benefits cost for each of the three years ended December 31, 2024, 2023 and 2022:

	Pension Benefits			Other Postretirement Benefits		
(in millions)	**2024**	2023	2022	**2024**	2023	2022
Components of Net Periodic Benefit (Income) Cost[1]						
Service cost	**$ 21.9**	$ 20.5	$ 27.8	**$ 5.0**	$ 5.1	$ 6.5
Interest cost	**64.9**	68.4	40.5	**22.0**	21.8	12.0
Expected return on assets	**(95.3)**	(94.5)	(90.8)	**(16.1)**	(15.1)	(16.2)
Amortization of prior service cost (credit)	**0.1**	0.1	0.1	**(1.8)**	(2.1)	(2.2)
Recognized actuarial loss	**28.6**	33.7	20.3	**3.2**	3.3	2.6
Settlement loss	**7.2**	9.2	12.4	**—**	—	—
Total Net Periodic Benefits Cost	**$ 27.4**	$ 37.4	$ 10.3	**$ 12.3**	$ 13.0	$ 2.7

[1]Service cost is presented in "Operation and maintenance" on the Statements of Consolidated Income. Non-service cost components are presented within "Other, net."

The following table provides the key assumptions that were used to calculate the net periodic benefits cost for our various plans:

	Pension Benefits			Other Postretirement Benefits		
	2024	2023	2022	**2024**	2023	2022
Weighted-average Assumptions to Determine Net Periodic Benefit Cost						
Discount rate - service cost	**5.06 %**	5.25 %	3.08 %	**5.14 %**	5.30 %	3.21 %
Discount rate - interest cost	**4.88 %**	5.06 %	2.11 %	**4.89 %**	5.07 %	2.24 %
Expected Long-Term Rate of Return on Plan Assets	**7.02 %**	7.00 %	4.80 %	**7.06 %**	6.96 %	5.72 %
Rate of Compensation Increases	**4.00 %**	4.00 %	4.00 %	**N/A**	N/A	N/A
Interest Crediting Rates	**4.00 %**	4.00 %	4.00 %	**N/A**	N/A	N/A

We assumed a 7.02% and 7.06% rate of return on pension and other postretirement plan assets, respectively, for our calculation of 2024 pension benefits and other postretirement benefits costs. These rates were primarily based on asset mix and historical rates of return and were adjusted in 2024 due to changes in asset allocation and projected market returns.

The following table provides other changes in plan assets and projected benefit obligations recognized in other comprehensive income or regulatory asset or liability:

	Pension Benefits		Other Postretirement Benefits	
(in millions)	**2024**	2023	**2024**	2023
Other Changes in Plan Assets and Projected Benefit Obligations Recognized in Other Comprehensive Income or Regulatory Asset or Liability				
Net prior service cost	**$ —**	$ —	**$ —**	$ 3.3
Net actuarial (gain) loss	**(13.1)**	(20.9)	**(26.4)**	16.0
Settlements/curtailments	**(7.2)**	(9.2)	**—**	—
Less: amortization of prior service cost	**(0.1)**	(0.1)	**1.8**	2.1
Less: amortization of net actuarial loss	**(28.6)**	(33.7)	**(3.2)**	(3.3)
Total Recognized in Other Comprehensive Income or Regulatory Asset or Liability	**$ (49.0)**	$ (63.9)	**$ (27.8)**	$ 18.1
Amount Recognized in Net Periodic Benefits Cost and Other Comprehensive Income or Regulatory Asset or Liability	**$ (21.6)**	$ (26.5)	**$ (15.5)**	$ 31.1

17. Share-Based Compensation

Prior to May 19, 2020, we issued share-based compensation to employees and non-employee directors under the NiSource Inc. 2010 Omnibus Plan ("2010 Omnibus Plan"), which was most recently approved by stockholders at the Annual Meeting of Stockholders held on May 12, 2015. The 2010 Omnibus Plan provided for awards to employees and non-employee directors of incentive and nonqualified stock options, stock appreciation rights, restricted stock, restricted stock units, performance shares, performance units, cash-based awards and other stock-based awards and superseded the Director Stock Incentive Plan (“Director Plan”) with respect to grants made after the effective date of the 2010 Omnibus Plan.

The stockholders approved and adopted the NiSource Inc. 2020 Omnibus Incentive Plan ("2020 Omnibus Plan") at the Annual Meeting of Stockholders held on May 19, 2020. The 2020 Omnibus Plan provides for awards to employees and non-employee directors of incentive and nonqualified stock options, stock appreciation rights, restricted stock, restricted stock units, performance shares, performance units, cash-based awards and other stock-based awards and supersedes the 2010 Omnibus Plan with respect to grants made after the effective date of the 2020 Omnibus Plan.

The 2020 Omnibus Plan provides that the number of shares of common stock of NiSource available for awards is 10,000,000 plus the number of shares subject to outstanding awards that expire or terminate for any reason that were granted under the

2020 Omnibus Plan, the 2010 Omnibus Plan or any other equity plan under which awards were outstanding as of May 19, 2020. At December 31, 2024, there were 7,216,823 shares available for future awards under the 2020 Omnibus Plan.

We recognized stock-based employee compensation expense of $32.1 million, $23.9 million and $19.0 million, during 2024, 2023 and 2022, respectively, as well as related tax benefits of $7.0 million, $7.7 million and $3.6 million, respectively. We recognized related excess tax benefits from the distribution of vested share-based employee compensation of $2.0 million, $2.9 million, and $0.4 million in 2024, 2023 and 2022, respectively.

As of December 31, 2024, the total remaining unrecognized compensation cost related to non-vested awards amounted to $46.7 million, which will be amortized over the weighted-average remaining requisite service period of 1.8 years.

Restricted Stock Units and Restricted Stock. We granted 655,713, 500,968, and 477,292 restricted stock units and shares of restricted stock to employees, subject to service conditions in 2024, 2023, and 2022, respectively. The total grant date fair value of the restricted stock units and shares of restricted stock during 2024, 2023, and 2022, respectively, was $17.1 million, $13.7 million, and $12.5 million. The grant date fair value for the 2024 and 2023 awards is based on the average market price of our common stock at the date of each grant. For the year ended 2022, the grant date fair value is based on the average market price of our common stock at the date of each grant less the present value of any dividends not received during the vesting period. The awards are expensed over the vesting period which is generally three years. As of December 31, 2024, 592,490, 393,509, and 270,325 non-vested restricted stock units and shares of restricted stock granted in 2024, 2023, and 2022, respectively, were outstanding. Our non-vested restricted stock units have a non-forfeitable right to dividend equivalents, with immaterial amounts paid in the periods ending December 31, 2024 and 2023. See Note 5, "Earnings Per Share," for further discussion.

In general, if an employee terminates employment before the service conditions lapse under the 2022, 2023 or 2024 awards due to (1) retirement or disability (as defined in the 2020 Omnibus Plan), or (2) death, the service conditions will lapse on the date of such termination with respect to a pro rata portion of the restricted stock units and shares of restricted stock based upon the percentage of the service period satisfied between the grant date and the date of the termination of employment. In the event of a change in control (as defined in the 2020 Omnibus Plan), all unvested shares of restricted stock and restricted stock units awarded will immediately vest upon termination of employment occurring in connection with a change in control. Termination due to any other reason, in general, will result in all unvested shares of restricted stock and restricted stock units awarded being forfeited effective on the employee's date of termination.

A summary of our restricted stock unit award transactions for the year ended December 31, 2024 is as follows:

(shares)	Restricted Stock Units	Weighted Average Award Date Fair Value Per Unit ($)
Non-vested at December 31, 2023	1,066,916	25.71
Granted	655,713	26.10
Forfeited	(167,057)	26.19
Vested	(227,452)	22.90
Non-vested at December 31, 2024	**1,328,120**	**26.49**

Employee Performance Shares. We granted 896,363 performance shares subject to service, performance and/or market-based vesting conditions in 2024. The performance conditions for these shares are based on the achievement of one non-GAAP financial measure, achievement of relative total shareholder return, and other operational metrics, which make up 55%, 25%, and 20% of the issued awards respectively.

The non-GAAP financial measure is cumulative adjusted earnings per share, which we define as diluted earnings per share adjusted for certain items. Relative total shareholder return, a market-based vesting condition, which we define as the annualized growth in dividends and share price of a share of our common stock (calculated using a 20 trading day average of our closing price over the performance period, approximately) compared to the total shareholder return of a predetermined peer group of companies. A Monte Carlo analysis was used to value the portion of these awards dependent on the market-based vesting condition. The grant date fair value of the non-GAAP financial measure shares is based on the closing stock price of our common stock at the date of each grant, which will be expensed over the requisite service period of three years. The conditions

for the remaining performance-based awards are based on operational goals of Annual Operational Index Scorecard (10%), Employee Engagement Index Score (5%), and Environmental Greenhouse Gas Reduction (5%).

In 2023, we granted 649,088 performance shares subject to service, performance and/or market-based vesting conditions. The performance conditions for these shares are based on the achievement of one non-GAAP financial measure, achievement of relative total shareholder return, and other operational metrics, which make up 50%, 25%, and 25% of the issued awards respectively. The operational metrics consist of goals of economic inclusion (5%), OPEX ("Operating Expenses") Index (10%), Employee Engagement Index Score (5%), and Environmental GHG Reduction (5%). The OPEX Index is further defined by goals related to risk mitigation and modernization of our infrastructure.

In 2022, we granted 566,086 performance shares subject to service, performance and/or market-based vesting conditions. The performance conditions for these shares are based on the achievement of one non-GAAP financial measure, and/or achievement of relative total shareholder return, outlined above. The number of shares that are eligible to vest based on these performance conditions are adjusted based on performance of the magnifier framework for 2022 awards. The operational magnifier framework for 2022 performance shares consists of three areas of focus, including safety, environment, and workforce, representing 20%, 10% and 10%, respectively.

The following table presents details of the performance awards described above.

Award Year	Service Conditions Lapse date	Performance Period	Award Conditions	Shares outstanding at 12/31/2024 *(shares)*	Grant Date Fair Value *(in millions)*
2024	2/26/2027	01/01/2024-12/31/2026	Non-GAAP Financial and Operational Measures	619,673	$ 17.4
			Relative Total Shareholder Return	206,524	$ 6.9
2023	2/28/2026	01/01/2023-12/31/2025	Non-GAAP Financial and Operational Measures	430,670	$ 13.3
			Relative Total Shareholder Return	143,540	$ 5.4
2022	2/28/2025	01/01/2022-12/31/2024	Non-GAAP Financial Measure	195,460	$ 7.4
			Relative Total Shareholder Return	195,460	$ 10.6

A summary of our performance award transactions for the year ended December 31, 2024 is as follows:

(shares)	Performance Awards	Weighted Average Grant Date Fair Value Per Unit ($)
Non-vested at December 31, 2023	1,558,509	28.01
Granted	896,363	27.05
Forfeited	(189,080)	31.75
Vested	(546,569)	21.95
Non-vested at December 31, 2024	**1,719,223**	**24.96**

Non-employee Director Awards. As of May 19, 2020, awards to non-employee directors may be made only under the 2020 Omnibus Plan. Currently, restricted stock units are granted annually to non-employee directors, subject to a non-employee director's election to defer receipt of such restricted stock unit award. The non-employee director's annual award of restricted stock units vest on the first anniversary of the grant date subject to special pro-rata vesting rules in the event of retirement or

disability (as defined in the award agreement), or death. The vested restricted stock units are payable as soon as practicable following vesting except as otherwise provided pursuant to the non-employee director's deferral election. Certain restricted stock units remain outstanding from the 2010 Omnibus Plan and the Director Plan. All such awards are fully vested and shall be distributed to the directors upon their separation from the Board.

As of December 31, 2024, 292,566 restricted stock units are outstanding to non-employee directors under either the 2020 Omnibus Plan, the 2010 Omnibus Plan or the Director Plan. Of this amount, 68,436 restricted stock units are unvested and expected to vest.

401(k) Match, Profit Sharing and Company Contribution. Eligible salaried employees hired after January 1, 2010 and hourly and union employees hired after January 1, 2013 receive a non-elective company contribution of 4.5% of eligible pay payable in cash or shares of NiSource common stock. We also have a voluntary 401(k) savings plan covering eligible union and nonunion employees that allows for periodic discretionary matches as a percentage of each participant's contributions payable in cash or shares. Further, we have a retirement savings plan that provides for discretionary profit sharing contributions to eligible employees. For the years ended December 31, 2024, 2023 and 2022, we recognized 401(k) match, profit sharing and non-elective contribution expense of $56.9 million, $50.7 million and $39.1 million, respectively.

18. Leases

Lease Descriptions. We are the lessee for substantially all of our leasing activity, which includes operating and finance leases for corporate and field offices, railcars, land, and fleet vehicles. Our corporate and field office leases and certain land leases have remaining terms between 1 and 39 years with options to renew the leases for up to 35 years. We lease railcars to transport coal to and from our electric generation facilities in Indiana. Our railcars are specifically identified in the lease agreements which have remaining lease terms between 1 and 3 years with options to renew for 1 year. Our fleet vehicles include trucks, trailers and equipment that have been customized specifically for use in the utility industry. We lease fleet vehicles for 1 year terms, after which we have the option to extend on a month-to-month basis or terminate with written notice. We elected the short-term lease practical expedient, allowing us to not recognize ROU assets or lease liabilities for all leases with a term of 12 months or less. ROU assets and liabilities on our Consolidated Balance Sheets do not include obligations for possible fleet vehicle lease renewals beyond the initial lease term. While we have the ability to renew these leases beyond the initial term, we are not reasonably certain to do so.

We have not provided material residual value guarantees for our leases, nor do our leases contain material restrictions or covenants. Lease contracts containing renewal and termination options are mostly exercisable at our sole discretion. Certain of our real estate and railcar leases include renewal periods in the measurement of the lease obligation if we have deemed the renewals reasonably certain to be exercised.

With respect to service contracts involving the use of assets, if we have the right to direct the use of the asset and obtain substantially all economic benefits from the use of an asset, we account for the service contract as a lease. Unless specifically provided to us by the lessor, we utilize NiSource's collateralized incremental borrowing rate commensurate to the lease term as the discount rate for all of our leases. ASC 842 permits a lessee, by class of underlying asset, not to separate nonlease components from lease components. Our policy is to apply this expedient for our leases of fleet vehicles, IT assets and railcars when calculating their respective lease liabilities.

Lease costs for the years ended December 31, 2024 and December 31, 2023 are presented in the table below. These costs include both amounts recognized in expense and amounts capitalized as part of the cost of another asset. Income statement presentation for these costs (when ultimately recognized on the income statement) is also included:

Year Ended December 31, *(in millions)*	Income Statement Classification	**2024**	2023
Finance lease cost			
Amortization of right-of-use assets	Depreciation and amortization	**$ 27.1**	$ 32.0
Interest on lease liabilities	Interest expense, net	**13.5**	8.6
Total finance lease cost		**40.6**	40.6
Operating lease cost	Operation and maintenance	**14.7**	11.3
Total lease cost		**$ 55.3**	$ 51.9

Our right-of-use assets and liabilities are presented in the following lines on the Consolidated Balance Sheets:

At December 31, *(in millions)*	Balance Sheet Classification	**2024**	2023
Assets			
Finance leases	Net Property, Plant and Equipment	**$ 222.9**	$ 184.3
Operating leases	Deferred charges and other	**26.4**	32.9
Total leased assets		**$ 249.3**	217.2
Liabilities			
Current			
Finance leases	Current portion of long-term debt	**$ 22.9**	23.8
Operating leases	Other accruals	**9.1**	8.3
Noncurrent			
Finance leases	Long-term debt, excluding amounts due within one year	**223.3**	181.6
Operating leases	Other noncurrent liabilities and deferred credits	**18.2**	25.8
Total lease liabilities		**$ 273.5**	$ 239.5

Other pertinent information related to leases was as follows:

Year Ended December 31, *(in millions)*	**2024**	2023
Cash paid for amounts included in the measurement of lease liabilities		
Operating cash flows used for finance leases	**$ 11.2**	$ 9.3
Operating cash flows used for operating leases	**14.5**	11.1
Financing cash flows used for finance leases	**26.9**	33.1
Right-of-use assets obtained in exchange for lease obligations		
Finance leases	**65.9**	64.5
Operating leases	**$ 12.2**	$ 5.6

	December 31, 2024	December 31, 2023
Weighted-average remaining lease term (years)		
Finance leases	**20.5**	16.4
Operating leases	**5.6**	6.7
Weighted-average discount rate		
Finance leases	**5.6 %**	5.5 %
Operating leases	**4.5 %**	4.3 %

Maturities of our lease liabilities as of December 31, 2024 were as follows:

As of December 31, 2024, *(in millions)*	Total	Finance Leases	Operating Leases
2025	$ 44.6	$ 34.6	$ 10.0
2026	34.7	29.4	5.3
2027	28.5	24.2	4.3
2028	26.1	23.0	3.1
2029	21.5	19.0	2.5
Thereafter	304.9	299.2	5.7
Total lease payments	460.3	429.4	30.9
Less: Imputed interest	(186.8)	(183.2)	(3.6)
Total	$ 273.5	$ 246.2	$ 27.3
Reported as of December 31, 2024			
Short-term lease liabilities	32.0	22.9	9.1
Long-term lease liabilities	241.5	223.3	18.2
Total lease liabilities	$ 273.5	$ 246.2	$ 27.3

19. Other Commitments and Contingencies

A. Contractual Obligations. We have certain contractual obligations requiring payments at specified periods. The obligations include long-term debt, lease obligations, energy commodity contracts and obligations for various services including pipeline capacity and outsourcing of IT services. The total contractual obligations in existence at December 31, 2024 and their maturities were:

(in millions)	Total	2025	2026	2027	2028	2029	After
Long-term debt [1]	$ 13,205.0	$ 1,260.0	$ —	$ 1,090.0	$ 1,055.0	$ 1,350.0	$ 8,450.0
Interest payments on long-term debt	8,090.3	566.2	551.1	531.7	481.6	453.9	5,505.8
Finance leases[2]	429.4	34.6	29.4	24.2	23.0	19.0	299.2
Operating leases[3]	30.9	10.0	5.3	4.3	3.1	2.5	5.7
Energy commodity contracts	119.7	118.5	0.3	0.3	0.4	0.2	—
Service obligations:							
Pipeline service obligations	2,694.6	685.5	631.2	609.2	373.2	245.2	150.3
IT service obligations	120.7	73.9	30.3	11.4	5.1	—	—
Plant equipment purchase obligations	173.5	140.5	24.9	4.3	3.8	—	—
Other liabilities[4]	336.0	287.0	7.9	7.7	7.6	7.7	18.1
Total contractual obligations	$ 25,200.1	$ 3,176.2	$ 1,280.4	$ 2,283.1	$ 1,952.8	$ 2,078.5	$ 14,429.1

[1] Long-term debt balance excludes unamortized issuance costs and discounts of $95.5 million.
[2] Finance lease payments shown above are inclusive of interest totaling $183.2 million.
[3] Operating lease payments shown above are inclusive of interest totaling $3.6 million. Operating lease balances do not include obligations for possible fleet vehicle lease renewals beyond the initial lease term. While we have the ability to renew these leases beyond the initial term, we are not reasonably certain to do so as they are renewed month-to-month after the first year.
[4] Other liabilities shown above are primarily related to the Dunns Bridge II and Indiana Crossroads Solar Developer payments due in 2025 and ongoing maintenance service agreements for our renewable joint ventures.

Purchase and Service Obligations. We have entered into various purchase and service agreements whereby we are contractually obligated to make certain minimum payments in future periods. Our energy commodity contracts are for the purchase of physical quantities of natural gas, electricity and coal. Our service obligations, consisting of pipeline service obligations and IT service obligations, encompass a broad range of business support and maintenance functions which are generally described below. Our plant equipment purchase obligations are for plant equipment, typically for generation assets, with long lead times that require payments made over time

Our subsidiaries have entered into various energy commodity contracts to purchase physical quantities of natural gas, electricity and coal. These amounts represent the minimum quantity of these commodities we are obligated to purchase at both fixed and variable prices. To the extent contractual purchase prices are variable, obligations disclosed in the table above are valued at market prices as of December 31, 2024.

NIPSCO has PPAs representing a total of 600 MW of wind power, with contracts expiring between 2038 and 2040. No minimum quantities are specified within these agreements due to the variability of electricity generation from wind, so no amounts related to these contracts are included in the table above. Upon early termination of one of these agreements by NIPSCO for any reason (other than material breach by the counterparties), NIPSCO may be required to pay a termination charge that could be material depending on the events giving rise to termination and the timing of the termination.

We have pipeline service agreements that provide for pipeline capacity, transportation and storage services. These agreements, which have expiration dates ranging from 2028 to 2038, require us to pay fixed monthly charges.

NIPSCO has contracts with three major rail operators providing coal transportation services for which there are certain minimum payments. These service contracts extend for various periods through 2025.

We have executed agreements with multiple IT service providers. The agreements extend for various periods through 2029.

B. Guarantees and Indemnities. We and certain of our subsidiaries enter into various agreements providing financial or performance assurance to third parties on behalf of certain subsidiaries as part of normal business. Such agreements include guarantees and stand-by letters of credit. These agreements are entered into primarily to support or enhance the creditworthiness otherwise attributed to a subsidiary on a stand-alone basis, thereby facilitating the extension of sufficient credit to accomplish the subsidiaries' intended commercial purposes. At December 31, 2024 and 2023, we issued stand-by letters of credit of $9.4 million and $9.9 million, respectively, for the benefit of third parties.

We provide guarantees related to our future performance under BTAs for our renewable generation projects. At December 31, 2024 and 2023, our guarantees for multiple BTAs totaled $1,127.5 million and $646.1 million, respectively. The amount of each guaranty will decrease upon completion of certain milestones for the construction of the facilities, including mechanical and substantial completion. See "- E. Other Matters - Generation Transition," below for more information.

We provide guarantees related to some of our rail and pipeline service agreements. If we do not meet our contractual obligations under the terms of these agreements we would be required to pay up to a maximum of $61.7 million.

C. Legal Proceedings. From time to time, various legal and regulatory claims and proceedings are pending or threatened against the Company and its subsidiaries. While the amounts claimed may be substantial, the Company is unable to predict with certainty the ultimate outcome of such claims and proceedings. The Company establishes reserves whenever it believes it to be appropriate for pending litigation matters. However, the actual results of resolving the pending litigation matters may be substantially higher than the amounts reserved. If one or more other matters were decided against us, the effects could be material to our results of operations in the period in which we would be required to record or adjust the related liability and could also be material to our cash flows in the periods that we would be required to pay such liability. Due to the inherent uncertainty of litigation, there can be no assurance that the resolution of any particular claim, proceeding or investigation would not have a material adverse effect on our results of operations, financial position or liquidity.

Other Claims and Proceedings. We are also party to certain other claims, regulatory and legal proceedings arising in the ordinary course of business in each state in which we have operations, and based upon an investigation of these matters and discussion with legal counsel, we believe the ultimate outcome of such other legal proceedings to be individually, or in aggregate, not material at this time.

D. Environmental Matters. Our operations are subject to environmental statutes and regulations related to air quality, water quality, hazardous waste and solid waste. We believe that we are in substantial compliance with the environmental regulations currently applicable to our operations.

It is management's continued intent to address environmental issues in cooperation with regulatory authorities in such a manner as to achieve mutually acceptable compliance plans. However, there can be no assurance that fines and penalties will not be incurred. Management expects the majority of environmental assessment and remediation costs and asset retirement costs, further described below, to be recoverable through rates. See Note 11, "Asset Retirement Obligations" and Note 12, "Regulatory Matters," for additional detail.

As of December 31, 2024 and 2023, we had recorded a liability of $91.8 million and $80 million, respectively, to cover environmental remediation at various sites. This liability is included in "Other accruals" and "Other noncurrent liabilities and deferred credits" in the Consolidated Balance Sheets. We recognize costs associated with environmental remediation obligations when the incurrence of such costs is probable and the amounts can be reasonably estimated. The original estimates for remediation activities may differ materially from the amount ultimately expended. The actual future expenditures depend on many factors, including laws and regulations, the nature and extent of impact and the method of remediation. These expenditures are not currently estimable at some sites. We periodically adjust our liability as information is collected and estimates become more refined.

CERCLA. Our subsidiaries are potentially responsible parties at waste disposal sites under the CERCLA and similar state laws. Under CERCLA, each potentially responsible party can be held jointly, severally and strictly liable for the remediation costs as the EPA, or state, can allow the parties to pay for remedial action or perform remedial action themselves and request reimbursement from the potentially responsible parties. Our affiliates have retained CERCLA environmental liabilities, including remediation liabilities, associated with certain current and former operations. At this time, we cannot estimate the full cost of remediating properties that have not yet been investigated, but it is possible that the future costs could be material to the Consolidated Financial Statements.

MGP. We maintain a program to identify and investigate former MGP sites where gas distribution subsidiaries or predecessors may have liability. The program has identified 51 such sites where liability is probable. Remedial actions at many of these sites are being overseen by state or federal environmental agencies through consent agreements or voluntary remediation agreements.

We utilize a probabilistic model to estimate our future remediation costs related to MGP sites. The model was prepared with the assistance of a third party and incorporates our experience and general industry experience with remediating MGP sites. We complete an annual refresh of the model in the second quarter of each fiscal year. We recorded an $11.2 million increase to the estimated future remediation costs as a result of the refresh completed in the second quarter of 2024. No material changes to the estimated future remediation costs were noted as a result of an internal quarterly review of environmental reserves completed as of December 31, 2024. Our total estimated liability related to the facilities subject to remediation was $86.4 million and $73.7 million at December 31, 2024 and 2023, respectively. The liability represents our best estimate of the probable cost to remediate the MGP sites. Our model indicates that it is reasonably possible that remediation costs could vary by as much as $16.3 million in addition to the costs noted above. Remediation costs are estimated based on the best available information, applicable remediation standards at the balance sheet date, and experience with similar facilities.

CCRs. NIPSCO continues to meet the compliance requirements established by the EPA for the regulation of CCRs. The CCR rule requirements currently in effect required revisions to previously recorded legal obligations associated with the retirement of certain NIPSCO facilities. The actual asset retirement costs related to the CCR rule may vary substantially from the estimates used to record the increased asset retirement obligation due to the uncertainty about the requirements that will be established by environmental authorities, compliance strategies that will be used and the preliminary nature of available data used to estimate costs. As allowed by the rule, NIPSCO will continue to collect data over time to determine the specific compliance solutions and associated costs and, as a result, the actual costs may vary.

On May 8, 2024, the EPA finalized changes to the current CCR regulations ("Legacy CCR Rule") which address inactive surface impoundments at inactive facilities, referred to as legacy impoundments, and CCR management units ("CCRMUs") at inactive and active facilities. The rule largely requires these newly regulated units to conform to existing requirements, such as groundwater monitoring, closure requirements, and post-closure care. During 2024, we recorded additional asset retirement obligations of $149.7 million to cover probable and estimable compliance activities associated with the Legacy CCR Rule with an offsetting regulatory asset. Facility evaluations for CCRMUs are required by February 2026 and 2027. NIPSCO continues to assess whether existing legal obligations associated with the retirement of certain facilities must be revised and to estimate probable additional required asset retirement costs. NIPSCO expects to receive recovery of any such costs through existing and future depreciation rates.

E. Other Matters

Generation Transition. NIPSCO has executed several BTAs with developers to construct renewable generation facilities. NIPSCO has received IURC approval for all of its BTAs and PPAs. In October 2024, NIPSCO contracted with a developer to convert the previously approved Templeton Wind PPA to a BTA and has provided a notice of intent to file a CPCN with the IURC. In addition to IURC approval, NIPSCO's purchase obligation under certain BTAs is dependent on timely completion of construction. Certain agreements require NIPSCO to make partial payments upon the developer's completion of significant construction milestones. With respect to BTAs for which tax equity partnerships are utilized, once the tax equity partner has earned its negotiated rate of return and we have reached the agreed upon contractual date, NIPSCO has the option to purchase at fair market value the remaining interest in the JV from the tax equity partner. In January 2024, the IURC approved the full ownership of Cavalry and Dunns Bridge II which will allow those BTAs to be executed through direct ownership. In March 2024, Cavalry achieved mechanical completion, resulting in NIPSCO making a $110.6 million payment to the developer. In May 2024, Cavalry achieved substantial completion and commenced commercial operations, resulting in NIPSCO making a $114.9 million payment to the developer. In August 2024, the IURC approved full ownership of the Gibson and Fairbanks projects as well as an increase to the cost of the Fairbanks project. In January 2025, Fairbanks achieved mechanical completion resulting in NIPSCO making a $336.6 million payment to the developer. In September 2024, Dunns Bridge II achieved mechanical completion, resulting in NIPSCO making a $153.3 million payment to the developer. In January 2025, substantial completion was achieved requiring a final payment of $217.6 million to be paid in February 2025. NIPSCO has filed a request to modify the ownership structure for the Templeton wind project to become a wholly owned project.

NIPSCO Minority Interest Transaction. On December 31, 2023, pursuant to the terms of the BIP Purchase Agreement and simultaneously with the closing of the NIPSCO Minority Interest Transaction, Blackstone, NIPSCO Holdings I, NIPSCO

Holdings II and NiSource entered into an Amended and Restated Limited Liability Company Agreement (the "LLC Agreement") of NIPSCO Holdings II. Specifically, under the terms of the LLC Agreement, Blackstone will provide up to $250 million in additional capital contributions over a three-year period after the closing, which the obligation is backed by an Equity Commitment Letter from an affiliate of Blackstone. Under the LLC Agreement, Blackstone is entitled to appoint two directors to the board of directors of NIPSCO Holdings II (the "Board") so long as Blackstone (together with any approved affiliate) holds at least a 17.5% percentage interest (as defined in the LLC Agreement). In connection with the closing, Blackstone appointed two directors to the Board, such that the Board is now comprised of seven directors, two appointed by Blackstone and five appointed by NiSource. The LLC Agreement also contains certain investor protections, including, among other things, requiring Blackstone approval for Holdings II to take certain major actions. In addition, the LLC Agreement contains certain terms regarding transfer rights and other obligations applicable to both Blackstone and NiSource. The LLC Agreement establishes, among other things, governance rights, exit rights, requirements for additional capital contributions, mechanics for distributions, and other arrangements for Holdings II following the closing. On January 31, 2024, BIP transferred a 4.5% equity interest in NIPSCO Holdings II to BIP Blue Buyer VCOC L.L.C., a Delaware limited liability company and also an affiliate of Blackstone. Effective upon the closing of this transfer, the members of NIPSCO Holdings II entered into a Second Amended and Restated Limited Liability Company Operating Agreement of NIPSCO Holdings II (the "Amended LLC Agreement"). The two affiliates of Blackstone must vote their equity holdings under the Amended LLC Agreement as one investor.

Refer to Note 4, "Noncontrolling Interests," for detailed discussion of accounting for the NIPSCO Minority Interest Transaction.

20. Accumulated Other Comprehensive Loss

The following table displays the activity of Accumulated Other Comprehensive Loss, net of tax:

(in millions)	Gains and Losses on Securities[1]	Gains and Losses on Cash Flow Hedges[1]	Pension and OPEB Items[1]	Accumulated Other Comprehensive Loss[1]
Balance as of January 1, 2022	**$ 2.1**	**$ (122.5)**	**$ (6.4)**	**$ (126.8)**
Other comprehensive (loss) income before reclassifications	(13.7)	109.7	(8.9)	87.1
Amounts reclassified from accumulated other comprehensive loss	0.4	0.2	2.0	2.6
Net current-period other comprehensive (loss) income	(13.3)	109.9	(6.9)	89.7
Balance as of December 31, 2022	**$ (11.2)**	**$ (12.6)**	**$ (13.3)**	**$ (37.1)**
Other comprehensive (loss) income before reclassifications	3.1	(0.5)	(1.4)	1.2
Amounts reclassified from accumulated other comprehensive loss	0.8	0.3	1.2	2.3
Net current-period other comprehensive (loss) income	3.9	(0.2)	(0.2)	3.5
Balance as of December 31, 2023	**$ (7.3)**	**$ (12.8)**	**$ (13.5)**	**$ (33.6)**
Other comprehensive income (loss) before reclassifications	1.5	—	(1.2)	0.3
Amounts reclassified from accumulated other comprehensive loss	1.8	(0.4)	1.5	2.9
Net current-period other comprehensive income (loss)	3.3	(0.4)	0.3	3.2
Balance as of December 31, 2024	**$ (4.0)**	**$ (13.2)**	**$ (13.2)**	**$ (30.4)**

[1]All amounts are net of tax. Amounts in parentheses indicate debits.

21. Business Segment Information

Our reportable segments reflect the manner in which our business is managed and our resources are allocated. Following the consummation of the NIPSCO Minority Interest Transaction, we revised how we evaluate results and allocate resources across our business with an increased focus on operating performance at the state level. Refer to Note 4, "Noncontrolling Interests," for additional information on the NIPSCO Minority Interest Transaction. At December 31, 2024, our operations are divided into two primary reportable segments, the Columbia Operations and the NIPSCO Operations segments. Columbia Operations aggregates the results of the fully regulated and wholly owned subsidiaries of NiSource Gas Distribution Group, Inc. (a holding company that owns Columbia of Kentucky, Columbia of Maryland, Columbia of Ohio, Columbia of Pennsylvania, and Columbia of Virginia). Each Columbia distribution company is an operating segment which we aggregate to form the Columbia Operations reportable segment. NIPSCO Operations includes the results of NIPSCO Holdings I and its majority-owned subsidiaries, including NIPSCO, which has fully regulated gas and electric operations in northern Indiana. Our historical segment disclosures have been recast to be consistent with the current presentation.

The remainder of our operations, which are not significant enough on a stand-alone basis to warrant treatment as an operating segment, are presented as "Corporate and Other" in the subsequent reconciliation table and primarily are comprised of interest expense on holding company debt and unallocated corporate costs and activities. Refer to Note 3, "Revenue Recognition," for additional information on our segments and their sources of revenues. The following table provides information about our reportable segments. We use operating income as our primary measurement for each of the reported segments and make decisions on financing, dividends and taxes at the corporate level on a consolidated basis. We provide this measure to our Chief Operating Decision Maker, the CEO, who utilizes this measure to make operating segment level strategy decisions based on budget-to-actual variances and against prior periods to allocate resources accordingly. Segment revenues include intersegment sales to affiliated subsidiaries, which are eliminated in consolidation. Affiliated sales are recognized on the basis of prevailing market, regulated prices or at levels provided for under contractual agreements. Operating income is derived from revenues and expenses directly associated with each segment.

Year Ended December 31, 2024 (in millions)

	Columbia Operations	NIPSCO Operations	Total of Reportable Segments
Operating Revenues			
External Revenue	$ 2,703.2	$ 2,751.0	$ 5,454.2
Intersegment Revenue	12.8	1.0	13.8
Total Operating Revenue	**$ 2,716.0**	**$ 2,752.0**	**$ 5,468.0**
Cost of energy	514.7	617.5	1,132.2
O&M	837.5	761.4	1,598.9
Depreciation	409.1	590.3	999.4
Total other taxes	218.6	64.3	282.9
Other segment items[(1)]	7.4	(1.3)	6.1
Operating Income	**$ 728.7**	**$ 719.8**	**$ 1,448.5**
Capital Expenditures[(2)]	**$ 1,209.0**	**$ 2,252.4**	**$ 3,461.4**
Assets	**$ 14,769.5**	**$ 15,823.5**	**$ 30,593.0**

[(1)]Other segment items consists of Loss (gain) on Sale or Impairment of Assets and other segment income or expenses deemed insignificant which are used to reach our measurement of segment profit or loss, Operating Income.
[(2)]Amounts differ from those presented on the Statements of Consolidated Cash Flows primarily due to the inclusion of capital expenditures in current liabilities, the capitalized portion of the Corporate Incentive Plan payout, and AFUDC Equity.

Year Ended December 31, 2023 (in millions)

	Columbia Operations	NIPSCO Operations	Total of Reportable Segments
Operating Revenues			
External Revenue	$ 2,733.9	$ 2,770.7	$ 5,504.6
Intersegment Revenue	12.2	0.9	13.1
Total Operating Revenue	**$ 2,746.1**	**$ 2,771.6**	**$ 5,517.7**
Cost of energy	645.0	888.3	1,533.3
O&M	792.3	787.7	1,580.0
Depreciation	371.7	493.8	865.5
Total other taxes	198.8	57.9	256.7
Other segment items[(1)]	—	2.2	2.2
Operating Income	**$ 738.3**	**$ 541.7**	**$ 1,280.0**
Capital Expenditures[(2)]	**$ 1,159.6**	**$ 1,294.8**	**$ 2,454.4**
Assets	**$ 13,664.5**	**$ 13,962.6**	**$ 27,627.1**

[(1)]Other segment items consists of Loss(gain) on Sale or Impairment of Assets and other segment income or expenses deemed insignificant which are used to reach our measurement of segment profit or loss, Operating Income.
[(2)]Amounts differ from those presented on the Statements of Consolidated Cash Flows primarily due to the inclusion of capital expenditures in current liabilities, the capitalized portion of the Corporate Incentive Plan payout, and AFUDC Equity.

Year Ended December 31, 2022 (in millions)

	Columbia Operations	NIPSCO Operations	Total of Reportable Segments
Operating Revenues			
External Revenue	$ 2,951.9	$ 2,886.2	$ 5,838.1
Intersegment Revenue	12.5	0.9	13.4
Total Operating Revenue	**$ 2,964.4**	**$ 2,887.1**	**$ 5,851.5**
Cost of energy	978.4	1,132.1	2,110.5
O&M	791.3	740.4	1,531.7
Depreciation	329.4	449.4	778.8
Total other taxes	184.2	72.1	256.3
Other segment items[(1)]	(103.9)	—	(103.9)
Operating Income	**$ 785.0**	**$ 493.1**	**$ 1,278.1**
Capital Expenditures[(2)]	**$ 1,237.9**	**$ 1,018.9**	**$ 2,256.8**
Assets	**$ 13,059.4**	**$ 11,759.9**	**$ 24,819.3**

[(1)]Other segment items consists of proceeds from a property insurance settlement related to the Greater Lawrence Incident and other segment income or expenses deemed insignificant which are used to reach our measurement of segment profit or loss, Operating Income.
[(2)]Amounts differ from those presented on the Statements of Consolidated Cash Flows primarily due to the inclusion of capital expenditures in current liabilities, the capitalized portion of the Corporate Incentive Plan payout, and AFUDC Equity.

To reconcile the segment tables above to consolidated NiSource:

Year Ended December 31, 2024 (in millions)

	Total Reportable Segments	Corporate and Other	Eliminations	Consolidated NiSource
Total Operating Revenue	$ 5,468.0	$ 581.9	$ (594.8)	$ 5,455.1
Operating Income	1,448.5	7.0	—	1,455.5
Capital Expenditures	3,461.4	231.1	—	3,692.5
Assets	30,593.0	1,195.1	—	31,788.1

Year Ended December 31, 2023 (in millions)

	Total Reportable Segments	Corporate and Other	Eliminations	Consolidated NiSource
Total Operating Revenue	$ 5,517.7	$ 504.6	$ (516.9)	$ 5,505.4
Operating Income	1,280.0	15.5	—	1,295.5
Capital Expenditures	2,454.4	236.3	—	2,690.7
Assets	27,627.1	3,450.1	—	31,077.2

Year Ended December 31, 2022 (in millions)

	Total Reportable Segments	Corporate and Other	Eliminations	Consolidated NiSource
Total Operating Revenue	$ 5,851.5	$ 477.5	$ (478.4)	$ 5,850.6
Operating Income (Loss)	1,278.1	(12.3)	—	1,265.8
Capital Expenditures	2,256.8	41.2	—	2,298.0
Assets	24,819.3	1,917.3	—	26,736.6

22. Other, Net

The following table displays the components of Other, Net included on the Statements of Consolidated Income:

Year Ended December 31, *(in millions)*	**2024**	2023	2022
Interest income	**$ 10.4**	$ 9.0	$ 4.3
AFUDC equity	**75.1**	25.2	15.1
Charitable contributions	**(5.4)**	(1.8)	(4.4)
Pension and other postretirement non-service cost[(1)]	**(13.5)**	(24.0)	27.6
Interest rate swap settlement gain	**—**	—	10.0
Miscellaneous	**(2.1)**	(0.4)	(0.4)
Total Other, net	**$ 64.5**	$ 8.0	$ 52.2

(1) See Note 16, "Pension and Other Postemployment Benefits," for additional information.

23. Interest Expense, Net

The following table displays the components of Interest Expense, Net included on the Statements of Consolidated Income:

Year Ended December 31, *(in millions)*	**2024**	2023	2022
Interest on long-term debt	**$ 506.2**	$ 404.1	$ 344.5
Interest on short-term borrowings	**43.2**	108.9	22.7
Debt discount/cost amortization	**13.8**	13.5	11.7
Accounts receivable securitization fees	**1.5**	2.7	2.5
Allowance for borrowed funds used and interest capitalized during construction	**(40.1)**	(25.3)	(6.7)
Debt-based post-in-service carrying charges	**(26.4)**	(30.7)	(21.1)
Other	**19.0**	16.4	8.0
Total Interest Expense, net	**$ 517.2**	$ 489.6	$ 361.6

24. Supplemental Cash Flow Information

The following table provides additional information regarding our Consolidated Statements of Cash Flows for the years ended December 31, 2024, 2023 and 2022:

Year Ended December 31, *(in millions)*	**2024**	2023	2022
Supplemental Disclosures of Cash Flow Information			
Non-cash transactions:			
Capital expenditures included in current liabilities	**$ 367.0**	$ 315.0	$ 275.1
Assets acquired under a finance lease	**65.9**	64.5	19.3
Assets acquired under an operating lease	**12.2**	5.6	8.8
Assets recorded for asset retirement obligations[(1)]	**277.4**	61.1	6.3
Purchase contract liability, net of fees and payments[(2)]	**—**	—	65.0
Schedule of interest and income taxes paid:			
Cash paid for interest on debt, net of interest capitalized amounts	**$ 468.2**	$ 433.9	$ 343.8
Cash paid for interest on finance leases	**11.2**	8.6	8.5
Cash paid for income taxes, net of refunds	**4.3**	9.4	7.2

[(1)]See Note 11, "Asset Retirement Obligations," for additional information.
[(2)]Refer to Note 6, "Equity," for additional information.

NISOURCE INC.

SCHEDULE II – VALUATION AND QUALIFYING ACCOUNTS

Twelve months ended December 31, 2024

($ in millions)	Balance Jan. 1, 2024	Additions: Charged to Costs and Expenses	Additions: Charged to Other Account [1]	Deductions for Purposes for which Reserves were Created	Balance Dec. 31, 2024
Reserves Deducted in Consolidated Balance Sheet from Assets to Which They Apply:					
Reserve for accounts receivable	$ 22.9	$ 23.2	$ 32.3	$ 54.7	$ 23.7
Reserve for deferred charges and other	1.3	—	(0.2)	—	1.1

Twelve months ended December 31, 2023

($ in millions)	Balance Jan. 1, 2023	Additions: Charged to Costs and Expenses	Additions: Charged to Other Account [1]	Deductions for Purposes for which Reserves were Created	Balance Dec. 31, 2023
Reserves Deducted in Consolidated Balance Sheet from Assets to Which They Apply:					
Reserve for accounts receivable	$ 23.9	$ 23.4	$ 36.6	$ 61.0	$ 22.9
Reserve for deferred charges and other	1.0	—	0.3	—	1.3

Twelve months ended December 31, 2022

($ in millions)	Balance Jan. 1, 2022	Additions: Charged to Costs and Expenses	Additions: Charged to Other Account [1]	Deductions for Purposes for which Reserves were Created	Balance Dec. 31, 2022
Reserves Deducted in Consolidated Balance Sheet from Assets to Which They Apply:					
Reserve for accounts receivable	$ 23.5	$ 20.6	$ 36.4	$ 56.6	$ 23.9
Reserve for deferred charges and other	2.3	—	(1.3)	—	1.0

[1] Charged to Other Accounts reflects the deferral of bad debt expense to a regulatory asset or the movement of the reserve between short term and long term.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

Our CEO and CFO are responsible for evaluating the effectiveness of disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)). Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by the Company in reports that are filed or submitted under the Exchange Act are accumulated and communicated to management, including our CEO and CFO, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon that evaluation, our CEO and CFO concluded that, as of the end of the period covered by this report, disclosure controls and procedures were effective to provide reasonable assurance that financial information was processed, recorded and reported accurately.

Management's Annual Report on Internal Control over Financial Reporting

Our management, including our CEO and CFO, are responsible for establishing and maintaining internal control over financial reporting, as such term is defined under Rule 13a-15(f) or Rule 15d-15(f) promulgated under the Exchange Act. However, management would note that a control system can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Our management has adopted the 2013 framework set forth in the Committee of Sponsoring Organizations of the Treadway Commission report, Internal Control - Integrated Framework, the most commonly used and understood framework for evaluating internal control over financial reporting, as its framework for evaluating the reliability and effectiveness of internal control over financial reporting. During 2024, we conducted an evaluation of our internal control over financial reporting. Based on this evaluation, management concluded that our internal control over financial reporting was effective as of the end of the period covered by this Annual Report on Form 10-K.

Deloitte & Touche LLP, our independent registered public accounting firm, issued an attestation report on our internal controls over financial reporting which is included herein.

Changes in Internal Controls

There have been no changes in our internal control over financial reporting during the most recently completed quarter covered by this report that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

NISOURCE INC.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of NiSource Inc.

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of NiSource Inc. and subsidiaries (the "Company") as of December 31, 2024, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2024, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements as of and for the year ended December 31, 2024, of the Company and our report dated February 12, 2025, expressed an unqualified opinion on those financial statements.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed 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. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ DELOITTE & TOUCHE LLP
Columbus, Ohio
February 12, 2025

ITEM 9B. OTHER INFORMATION

NiSource Inc.

Director and Officer Trading Arrangements

The following table describes any contracts, instructions or written plans for the sale or purchase of NiSource securities and intended to satisfy the affirmative defense conditions of Rule 10b5-1(c) of the Exchange Act that were adopted by our directors and executive officers during the year ended December 31, 2024:

Name and Title	Date of Adoption of Rule 10b-5-1 Trading Plan	Scheduled Expiration Date of Rule 10b5-1 Trading Plan[(1)]	Aggregate Number of Securities to Be Purchased or Sold
Shawn Anderson Executive Vice President, Chief Financial Officer	11/1/2024	5/30/2025	Sale of up to 12,900 shares of common stock in multiple transactions
Michael Jesanis Director	11/11/2024	5/16/2025	Sale of up to 10,092 shares of common stock in multiple transactions

[(1)]A trading plan may also expire on such earlier date that all transactions under the trading plan are completed.

During the year ended December 31, 2024, none of our directors or executive officers terminated a Rule 10b5-1 trading plan or adopted or terminated a non-Rule 10b5-1 trading arrangement (as defined in Item 408(c) of Regulation S-K).

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS

Not applicable.

PART III

NiSource Inc.

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Except for the information required by this item with respect to our executive officers included at the end of Part I of this report on Form 10-K and the information with respect to our insider trading policy set forth below, the information required by this Item 10 is incorporated herein by reference to the discussion in "Proposal 1 Election of Directors," "Corporate Governance - Board Committee Composition," "Corporate Governance - Code of Business Conduct," and "Delinquent Section 16(a) Reports" of the Proxy Statement for the Annual Meeting of Stockholders to be held on May 12, 2025.

Insider Trading Policy

The Company has adopted an Insider Trading Policy, our "Securities Transaction Compliance Policy", governing the purchase, sale, and/or other dispositions of the Company's securities by our directors and all employees, including officers as defined under Rule 16a-1(f) of the Securities Exchange Act of 1934 and certain designated employees as well as their immediate family and members of their households, that we believe is reasonably designed to promote compliance with insider trading laws, rules and regulations and the exchange listing standards applicable to us. A copy of our policy is filed as Exhibit 19.1 to this Annual Report on Form 10-K.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this Item 11 is incorporated herein by reference to the discussion in "Compensation and Human Capital Committee Interlocks and Insider Participation," "2024 Director Compensation," "2024 Executive Compensation," "Compensation Discussion and Analysis (CD&A)," "Assessment of Risk," "2024 Pay Versus Performance," and "Compensation and Human Capital Committee Report" of the Proxy Statement for the Annual Meeting of Stockholders to be held on May 12, 2025.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information required by this Item 12 is incorporated herein by reference to the discussion in "Security Ownership of Certain Beneficial Owners and Management," and "Equity Compensation Plan Information" of the Proxy Statement for the Annual Meeting of Stockholders to be held on May 12, 2025.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information required by this Item 13 is incorporated herein by reference to the discussion in "Corporate Governance - Policies and Procedures with Respect to Transactions with Related Persons" and "Corporate Governance - Director Independence" of the Proxy Statement for the Annual Meeting of Stockholders to be held on May 12, 2025.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required by this Item 14 is incorporated herein by reference to the discussion in "Independent Registered Public Accounting Firm Fees" of the Proxy Statement for the Annual Meeting of Stockholders to be held on May 12, 2025.

PART IV

NISOURCE INC.

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

Financial Statements and Financial Statement Schedules

The following financial statements and financial statement schedules filed as a part of the Annual Report on Form 10-K are included in Item 8, "Financial Statements and Supplementary Data."

	Page
Report of Independent Registered Public Accounting Firm (PCAOB ID: 34)	58
Statements of Consolidated Income	61
Statements of Consolidated Comprehensive Income	62
Consolidated Balance Sheets	63
Statements of Consolidated Cash Flows	65
Statements of Consolidated Stockholders' Equity	66
Notes to Consolidated Financial Statements	68
Schedule II	121

Exhibits

The exhibits filed herewith as a part of this report on Form 10-K are listed on the Exhibit Index below. Each management contract or compensatory plan or arrangement of ours, listed on the Exhibit Index, is separately identified by an asterisk.

Pursuant to Item 601(b), paragraph (4)(iii)(A) of Regulation S-K, certain instruments representing long-term debt of our subsidiaries have not been included as Exhibits because such debt does not exceed 10% of the total assets of ours and our subsidiaries on a consolidated basis. We agree to furnish a copy of any such instrument to the SEC upon request.

EXHIBIT NUMBER	DESCRIPTION OF ITEM
(1.1)	Form of Equity Distribution Agreement (incorporated by reference to Exhibit 1.1 of the NiSource Inc. Form 8-K filed on February 22, 2024).
(1.2)	Form of Master Forward Sale Confirmation (incorporated by reference to Exhibit 1.2 of the NiSource Inc. Form 8-K filed on February 22, 2024).
(2.1)	Separation and Distribution Agreement, dated as of June 30, 2015, by and between NiSource Inc. and Columbia Pipeline Group, Inc. (incorporated by reference to Exhibit 2.1 to the NiSource Inc. Form 8-K filed on July 2, 2015).
(3.1)	Articles of Incorporation of NiSource Inc., as amended and restated through October 21, 2024 (incorporated by reference to Exhibit 3.3 to the NiSource Inc. Form 8-K filed on October 22, 2024).
(3.2)	Bylaws of NiSource Inc., as amended and restated through October 21, 2024 (incorporated by reference to Exhibit 3.4 to the NiSource Inc. Form 8-K filed on October 22, 2024).
(3.3)	Certificate of Designations of 6.50% Series B Fixed-Rate Reset Cumulative Redeemable Perpetual Preferred Stock (incorporated by reference to Exhibit 3.1 of the NiSource Inc. Form 8-K filed on December 6, 2018).
(3.4)	Certificate of Designations of Series B-1 Preferred Stock (incorporated by reference to Exhibit 3.1 to the NiSource Inc. Form 8-K filed on December 27, 2018).
(3.5)	Certificate of Elimination of the Company with respect to the Series B Preferred Stock and Series B-1 Preferred Stock (incorporated by reference to Exhibit 3.1 of the NiSource Inc. Form 8-K filed on March 18, 2024).
(3.6)	Certificate of Elimination of the Company with respect to the Series C Preferred Stock, dated October 21, 2024, issued by NiSource Inc. (incorporated by reference to Exhibit 3.1 of the NiSource Inc. Form 8-K filed on October 22, 2024).
(3.7)	Certificate of Elimination of the Company with respect to the Series A Junior Participating Preferred Stock, dated October 21, 2024, issued by NiSource Inc. (incorporated by reference to Exhibit 3.2 of the NiSource Inc. Form 8-K filed on October 22, 2024).
(4.1)	Indenture, dated as of March 1, 1988, by and between Northern Indiana Public Service Company ("NIPSCO") and Manufacturers Hanover Trust Company, as Trustee (incorporated by reference to Exhibit 4 to the NIPSCO Registration Statement (Registration No. 33-44193)).

(4.2) First Supplemental Indenture, dated as of December 1, 1991, by and between Northern Indiana Public Service Company and Manufacturers Hanover Trust Company, as Trustee (incorporated by reference to Exhibit 4.1 to the NIPSCO Registration Statement (Registration No. 33-63870)).

(4.3) Indenture Agreement, dated as of February 14, 1997, by and between NIPSCO Industries, Inc., NIPSCO Capital Markets, Inc. and Chase Manhattan Bank as trustee (incorporated by reference to Exhibit 4.1 to the NIPSCO Industries, Inc. Registration Statement (Registration No. 333-22347)).

(4.4) Second Supplemental Indenture, dated as of November 1, 2000, by and among NiSource Capital Markets, Inc., NiSource Inc., New NiSource Inc., and The Chase Manhattan Bank, as trustee (incorporated by reference to Exhibit 4.45 to the NiSource Inc. Form 10-K for the period ended December 31, 2000).

(4.5) Indenture, dated November 14, 2000, among NiSource Finance Corp., NiSource Inc., as guarantor, and The Chase Manhattan Bank, as Trustee (incorporated by reference to Exhibit 4.1 to the NiSource Inc. Form S-3, dated November 17, 2000 (Registration No. 333-49330)).

(4.6) Form of 3.490% Notes due 2027 (incorporated by reference to Exhibit 4.1 to the NiSource Inc. Form 8-K filed on May 17, 2017).

(4.7) Form of 4.375% Notes due 2047 (incorporated by reference to Exhibit 4.2 to the NiSource Inc. Form 8-K filed on May 17, 2017).

(4.8) Form of 3.950% Notes due 2048 (incorporated by reference to Exhibit 4.1 to the NiSource Inc. Form 8-K filed on September 8, 2017).

(4.9) Second Supplemental Indenture, dated as of November 30, 2017, between NiSource Inc. and The Bank of New York Mellon, as trustee (incorporated by reference to Exhibit 4.4 to Post-Effective Amendment No. 1 to Form S-3 filed November 30, 2017 (Registration No. 333-214360)).

(4.10) Third Supplemental Indenture, dated as of November 30, 2017, between NiSource Inc. and The Bank of New York Mellon, as trustee (incorporated by reference to Exhibit 4.2 to the NiSource Inc. Form 8-K filed on December 1, 2017).

(4.11) Second Supplemental Indenture, dated as of February 12, 2018, between Northern Indiana Public Service Company and The Bank of New York Mellon, solely as successor trustee under the Indenture dated as of March 1, 1988 between the Company and Manufacturers Hanover Trust Company, as original trustee. (incorporated by reference to Exhibit 4.1 to the NiSource Inc. Form 10-Q filed on May 2, 2018).

(4.12) Fourth Supplemental Indenture, dated as of December 18, 2023, between NiSource, Inc. and The Bank of New York Mellon, as trustee, relating to the 7.99% Medium-Term Notes due 2027 and the 6.78% Senior Notes due 2027 (incorporated by reference to Exhibit 10.1 to the NiSource Inc. Form 8-K filed on December 18, 2023).

(4.13) Subordinated Indenture, dated as of May 16, 2024, between NiSource Inc. and The Bank of New York Mellon, as trustee (incorporated by reference to Exhibit 4.2 to the NiSource Form 8-K filed on May 16, 2024).

(4.14) First Supplemental Indenture, dated as of May 16, 2024, between NiSource Inc. and The Bank of New York Mellon, as trustee (incorporated by reference to Exhibit 4.3 to the NiSource Form 8-K filed on May 16, 2024).

(4.15) Second Supplemental Indenture, dated as of September 09, 2024, between NiSource Inc. and The Bank of New York Mellon, as trustee (incorporated by reference to Exhibit 4.2 to the NiSource Form 8-K filed on September 09, 2024).

(4.16) Deposit Agreement, dated as of December 5, 2018, among NiSource, Inc., Computershare Inc. and Computershare Trust Company, N.A., acting jointly as depositary, and the holders from time to time of the depositary receipts described therein (incorporated by reference to Exhibit 4.1 of the NiSource Inc. Form 8-K filed on December 6, 2018).

(4.17) Form of Depositary Receipt (incorporated by reference to Exhibit 4.1 of the NiSource Inc. Form 8-K filed on December 6, 2018).

(4.18) Amended and Restated Deposit Agreement, dated as of December 27, 2018, among NiSource, Inc., Computershare Inc. and Computershare Trust Company, N.A., acting jointly as depositary, and the holders from time to time of the depositary receipts described therein (incorporated by reference to Exhibit 4.1 to the NiSource Inc. Form 8-K filed on December 27, 2018).

(4.19) Form of Depositary Receipt (incorporated by reference to Exhibit 4.1 to the NiSource Inc. Form 8-K filed on December 27, 2018).

(4.20) Form of 2.950% Notes due 2029 (incorporated by reference to Exhibit 4.1 to NiSource Inc. Form 8-K filed on August 12, 2019).

(4.21) Amended and Restated NiSource Inc. Employee Stock Purchase Plan (incorporated by reference to Exhibit C to the Registrant's Definitive Proxy Statement on Schedule 14A, filed with the Commission on April 1, 2019).

(4.22) Form of 3.600% Notes due 2030 (incorporated by reference to Exhibit 4.1 to the NiSource Inc. Form 8-K filed on April 8, 2020).

(4.23) Form of 0.950% Notes due 2025 (incorporated by reference to Exhibit 4.1 to the NiSource Inc. Form 8-K filed on August 18, 2020).

(4.24) Form of 1.700% Notes due 2031(incorporated by reference to Exhibit 4.2 to the NiSource Inc. Form 8-K filed on August 18, 2020).

(4.25) Form of 5.000% Notes due 2052 (incorporated by reference to Exhibit 4.1 of the NiSource Inc. Form 8-K filed on June 10, 2022).

(4.26) Form of 5.250% Notes due 2028 (incorporated by reference to Exhibit 4.1 to the NiSource Inc. Form 8-K filed on March 24, 2023).

(4.27) Form of 5.400% Notes due 2033 (incorporated by reference to Exhibit 4.2 to the NiSource Inc. Form 8-K filed on June 9, 2023).

(4.28) Form of 5.350% Notes due 2034 (incorporated by reference to Exhibit 4.1 to the NiSource Inc. Form 8-K filed on March 14, 2024).

(4.29) Form of 6.950% Fixed-to-Fixed Reset Rate Junior Subordinated Notes due 2054 (incorporated by reference to Exhibit 4.1 to the NiSource Inc. Form 8-K filed on May 16, 2024).

(4.30) Form of 5.200% Notes due 2029 (incorporated by reference to Exhibit 4.1 to the NiSource Inc. Form 8-K filed on June 24, 2024).

(4.31) Form of 6.375% Fixed-to-Fixed Reset Rate Junior Subordinated Notes due 2055 (incorporated by reference to Exhibit 4.1 to the NiSource Inc. Form 8-K filed on September 09, 2024).

(4.32) Description of NiSource Inc.'s Securities Registered Under Section 12 of the Exchange Act.**

(4.33) Form of 6.25% Notes due 2040 (incorporated by reference to Exhibit 4.1 to the NiSource Inc. Form 8-K filed on December 6, 2010).

(4.34) Form of 5.95% Notes due 2041 (incorporated by reference to Exhibit 4.1 to the NiSource Inc. Form 8-K filed on June 10, 2011).

(4.35) Form of 5.80% Notes due 2042 (incorporated by reference to Exhibit 4.2 to the NiSource Inc. Form 8-K filed on November 17, 2011).

(4.36) Form of 5.25% Notes due 2043 (incorporated by reference to Exhibit 4.2 to the NiSource Inc. Form 8-K filed on June 14, 2012).

(4.37) Form of 4.80% Notes due 2044 (incorporated by reference to Exhibit 4.1 to the NiSource Inc. Form 8-K filed on April 12, 2013).

(4.38) Form of 5.65% Notes due 2045 (incorporated by reference to Exhibit 4.1 to the NiSource Inc. Form 8-K filed on October 7, 2013).

(10.1) 2010 Omnibus Incentive Plan (incorporated by reference to Exhibit B to the NiSource Inc. Definitive Proxy Statement to Stockholders for the Annual Meeting held on May 11, 2010, filed on April 2, 2010).*

(10.2) First Amendment to the 2010 Omnibus Incentive Plan (incorporated by reference to Exhibit 10.2 to the NiSource Inc. Form 10-K filed on February 18, 2014.)*

(10.3) 2010 Omnibus Incentive Plan (incorporated by reference to Exhibit C to the NiSource Inc. Definitive Proxy Statement to Stockholders for the Annual Meeting held on May 12, 2015, filed on April 7, 2015).*

(10.4) Second Amendment to the NiSource Inc. 2010 Omnibus Incentive Plan (incorporated by reference to Exhibit 10.1 to the NiSource Inc. Form 8-K filed October 23, 2015.)*

(10.5) Form of Amendment to Restricted Stock Unit Award Agreement related to Vested but Unpaid NiSource Restricted Stock Unit Awards for Nonemployee Directors of NiSource entered into as of July 13, 2015 (incorporated by reference to Exhibit 10.3 to the NiSource Inc. Form 10-Q filed on November 3, 2015).*

(10.6) Supplemental Life Insurance Plan effective January 1, 1991, as amended, (incorporated by reference to Exhibit 2 to the NIPSCO Industries, Inc. Form 8-K filed on March 25, 1992).*

(10.7) Form of Restricted Stock Unit Award Agreement for Nonemployee Directors under the 2010 Omnibus Incentive Plan (incorporated by reference to Exhibit 10.1 to NiSource Inc. Form 10-Q filed on August 2, 2011).*

(10.8) Form of Restricted Stock Unit Award Agreement for Nonemployee Directors under the 2010 Omnibus Incentive Plan (incorporated by reference to Exhibit 10.18 to the NiSource Inc. Form 10-K filed on February 22, 2017). *

(10.9) Amended and Restated NiSource Inc. Executive Deferred Compensation Plan effective November 1, 2012 (incorporated by reference to Exhibit 10.21 to the NiSource Inc. Form 10-K filed on February 19, 2013).*

(10.10) Amended and Restated Executive Deferred Compensation Plan, dated August 12, 2024 (incorporated by reference to Exhibit 10.1 of the NiSource Inc. Form 10-Q filed on October 30, 2024).*

(10.11) Note Purchase Agreement, dated as of August 23, 2005, by and among NiSource Finance Corp., as issuer, NiSource Inc., as guarantor, and the purchasers named therein (incorporated by reference to Exhibit 10.1 to the NiSource Inc. Current Report on Form 8-K filed on August 26, 2005).

(10.12) Amendment No. 1, dated as of November 10, 2008, to the Note Purchase Agreement by and among NiSource Finance Corp., as issuer, NiSource Inc., as guarantor, and the purchasers whose names appear on the signature page thereto (incorporated by reference to Exhibit 10.30 to the NiSource Inc. Form 10-K filed on February 27, 2009).

(10.13) Form of Change in Control and Termination Agreement (incorporated by reference to Exhibit 10.1 to the NiSource Inc. Form 10-Q filed on August 2, 2017).*

(10.14) Registration Rights Agreement, dated as of May 2, 2018, by and among NiSource Inc. and the purchasers named therein (incorporated by reference to Exhibit 10.2 of the NiSource Inc. Form 8-K filed on May 2, 2018).

(10.15) Amended and Restated NiSource Inc. Employee Stock Purchase Plan adopted as of February 1, 2019 (incorporated by reference to Exhibit C to the NiSource Inc. Definitive Proxy Statement to Stockholders for the Annual Meeting to be held on May 7, 2019, filed on April 1, 2019).

(10.16) Amended and Restated NiSource Inc. Employee Stock Purchase Plan adopted as of January 25, 2024 (incorporated by reference to Appendix B to the NiSource Inc. Definitive Proxy Statement to Stockholders for the Annual Meeting to be held on May 13, 2024, filed on April 1, 2024).

(10.17) Form of Cash-Based Award Agreement (incorporated by reference to Exhibit 10.41 of the NiSource Form 10-K filed on February 28, 2020). *

(10.18) 2020 Omnibus Incentive Plan (incorporated by reference to Exhibit A to the NiSource Inc. Definitive Proxy Statement to Stockholders for the Annual Meeting held on May 19, 2020, filed on April 13, 2020).*

(10.19) Form of Restricted Stock Unit Award Agreement for Nonemployee Directors under the 2020 Omnibus Incentive Plan (incorporated by reference to Exhibit 10.2 of the NiSource Inc. Form 10-Q filed on August 5, 2020).*

(10.2) NiSource Inc. Supplemental Executive Retirement Plan, as amended and restated effective November 1, 2020 (incorporated by reference to Exhibit 10.4 to the NiSource Inc. Form 10-Q filed on November 2, 2020).*

(10.21) Pension Restoration Plan for NiSource Inc. and Affiliates, as amended and restated effective November 1, 2020 (incorporated by reference to Exhibit 10.5 to the NiSource Inc. Form 10-Q filed on November 2, 2020).

(10.22) Savings Restoration Plan for NiSource Inc. and Affiliates, as amended and restated effective November 1, 2020 (incorporated by reference to Exhibit 10.6 to the NiSource Inc. Form 10-Q filed on November 2, 2020).*

(10.23) First Amendment to the Savings Restoration Plan for NiSource Inc. and Affiliates dated October 12, 2023 and effective November 1, 2020 (incorporated by reference to Exhibit 10.24 to the NiSource Inc. Form 10-K filed on February 21, 2024).*

(10.24) NiSource Inc. Executive Severance Policy, as amended and restated effective October 19, 2020 (incorporated by reference to Exhibit 10.7 to the NiSource Inc. Form 10-Q filed on November 2, 2020).*

(10.25) NiSource Next Voluntary Separation Program, effective as of August 5, 2020 (incorporated by reference to Exhibit 10.8 to the NiSource Inc. Form 10-Q filed on November 2, 2020).*

(10.26) Form of Restricted Stock Unit Award Agreement. (incorporated by reference to Exhibit 10.53 to the NiSource Inc. Form 10-K filed on February 17, 2021).*

(10.27) Form of Performance Share Unit Award Agreement. (incorporated by reference to Exhibit 10.54 to the NiSource Inc. Form 10-K filed on February 17, 2021).*

(10.28) Form of Special Performance Share Unit Award Agreement. (incorporated by reference to Exhibit 10.55 to the NiSource Inc. Form 10-K filed on February 17, 2021).*

(10.29) Sixth Amended and Restated Revolving Credit Agreement, dated as of February 18, 2022, among NiSource Inc., as Borrower, the Lenders party thereto, Barclays Bank PLC, as Administrative Agent, JPMorgan Chase Bank, N.A. and MUFG Bank, Ltd., as Co-Syndication Agents, Credit Suisse AG, New York Branch, Wells Fargo Bank, National Association, and Bank of America, National Association, as Co-Documentation Agents, Barclays Bank PLC and MUFG Bank, Ltd., as Co-Sustainability Structuring Agents, and Barclays Bank PLC, JPMorgan Chase Bank, N.A. MUFG Bank, Ltd., Credit Suisse Loan Funding LLC, Wells Fargo Securities, LLC, and BofA Securities, Inc., as Joint Lead Arrangers and Joint Bookrunners (incorporated by reference to Exhibit 10.1 of the NiSource Inc. Form 8-K filed on February 18, 2022).

(10.3) Amendment No. 1 to the Sixth Amended and Restated Revolving Credit Agreement dated February 18, 2022, made as of August 23, 2023 by and among NiSource Inc., the financial institutions listed on the signature pages and Barclays Bank PLC, as administrative agent (incorporated by reference to Exhibit 10.1 to the NiSource Inc. Form 8-K filed on August 23, 2023).

(10.31) First Amendment to the NiSource Inc. 2020 Omnibus Incentive Plan (incorporated by reference to Exhibit 10.1 of the NiSource Inc. Form 10-Q filed on May 4, 2022).

(10.32) Credit Agreement, dated as of December 20, 2022, among NiSource Inc., as Borrower, the lenders party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent, PNC Capital Markets LLC, as Syndication Agent, Bank of America, N.A. and Wells Fargo Bank, N.A., as Co-Documentation Agents and JPMorgan Chase Bank, N.A., PNC Capital Markets LLC, Bank of America, N.A. and Wells Fargo Securities, LLC, as Joint Lead Arrangers and Joint Bookrunners (incorporated by reference to Exhibit 10.1 of the NiSource Inc. Form 8-K filed on December 20, 2022).

(10.33) Amendment No. 1 to the Credit Agreement dated December 20, 2022, made as of October 5, 2023 by and among NiSource Inc., the financial institutions listed on the signature pages and JPMorgan Chase Bank, N.A., as administrative agent (incorporated by reference to Exhibit 10.1 to the NiSource Inc. Form 8-K filed on October 5, 2023).

(10.34) Credit Agreement, dated as of November 9, 2023, among NiSource Inc., as Borrower, the lenders party there to, and U.S. Bank National Association, as Administrative Agent, as Sole Lead Arranger and Bookrunner (incorporated by reference to Exhibit 10.1 to the NiSource Inc. Form 8-K filed on November 9, 2023).

(10.35) Augmenting Lender Supplement, dated December 6, 2023, by and among NiSource Inc., Mizuho Bank, LTD, Bank of Montreal. and U.S. Bank National Association (incorporated by reference to Exhibit 10.1 to the NiSource Inc. Form 8-K filed on December 6, 2023).

(10.36) Form of Restricted Stock Unit Award Agreement.(incorporated by reference to Exhibit 10.57 to the NiSource Inc. Form 10-K filed on February 22, 2023).*

(10.37) Form of Performance Share Unit Award Agreement (incorporated by reference to Exhibit 10.58 to the NiSource Inc. Form 10-K filed on February 22, 2023).*

(10.38) Form of Restricted Stock Unit Award Agreement. (incorporated by reference to Exhibit 10.59 to the NiSource Inc. Form 10-K filed on February 22, 2023).*

(10.39) Form of Performance Share Unit Award Agreement. (incorporated by reference to Exhibit 10.60 to the NiSource Inc. Form 10-K filed on February 22, 2023).*

(10.40) Purchase and Sale Agreement, dated as of June 17, 2023, among NiSource Inc., as the Parent, NIPSCO Holdings II LLC, as the Company, and BIP BLUE BUYER L.L.C., as the Investor (incorporated by reference to Exhibit 10.1 to the NiSource Inc. Form 8-K filed on June 20, 2023).

(10.41) Amendment No. 1 to the Purchase and Sale Agreement, dated as of July 6, 2023, among NiSource Inc., as the Parent, NIPSCO Holdings II LLC, as the Company, and BIP BLUE BUYER L.L.C., as the Investor (incorporated by reference to Exhibit 10.2 of the NiSource Inc. Form 10-Q filed on August 2, 2023).****

(10.42)	Amended and Restated Limited Liability Company Agreement of NIPSCO Holdings II LLC, dated December 31, 2023 (incorporated by reference to Exhibit 10.1 of the NiSource Inc. Form 8-K filed on January 2, 2024).****
(10.43)	Second Amended and Restated Limited Liability Company Agreement of NIPSCO Holdings II LLC, dated January 30, 2024 (incorporated by reference to Exhibit 10.44 to the NiSource Inc. Form 10-K filed on February 21, 2024).*
(10.44)	Form of 2024 CEO RSU Award Agreement (incorporated by reference to Exhibit 10.1 of the NiSource Inc. Form 8-K filed on January 26, 2024).*
(10.45)	Form of 2024 CEO PSU Award Agreement (incorporated by reference to Exhibit 10.2 of the NiSource Inc. Form 8-K filed on January 26, 2024).*
(10.46)	Form of RSU Award Agreement (for awards on or after 2024) (incorporated by reference to Exhibit 10.3 of the NiSource Inc. Form 8-K filed on January 26, 2024).*
(10.47)	Form of PSU Award Agreement (for awards on or after 2024) (incorporated by reference to Exhibit 10.48 to the NiSource Inc. Form 10-K filed on February 22, 2023).****
(10.48)	Separation Agreement dated March 15, 2024, between NiSource Inc. and Donald Brown (incorporated by reference to Exhibit 10.1 to the NiSource Inc. Form 8-K filed on March 15, 2024).
(19.1)	Securities Transaction Compliance Policy**
(21)	List of Subsidiaries.**
(23)	Consent of Deloitte & Touche LLP.**
(31.1)	Certification of Chief Executive Officer, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.**
(31.2)	Certification of Chief Financial Officer, pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.**
(32.1)	Certification of Chief Executive Officer, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (furnished herewith).**
(32.2)	Certification of Chief Financial Officer, pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (furnished herewith).**
(97.1)	NiSource Inc. Compensation Recoupment Policy.**
(101.INS)	Inline XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document. **
(101.SCH)	Inline XBRL Schema Document.**
(101.CAL)	Inline XBRL Calculation Linkbase Document.**
(101.LAB)	Inline XBRL Labels Linkbase Document.**
(101.PRE)	Inline XBRL Presentation Linkbase Document.**
(101.DEF)	Inline XBRL Definition Linkbase Document.**
(104)	Cover page Interactive Data File (formatted as inline XBRL, and contained in Exhibit 101.)

* Management contract or compensatory plan or arrangement of NiSource Inc.

** Exhibit filed herewith.

*** Schedules and exhibits have been omitted pursuant to Item 601(b)(2) of Regulation S-K. NiSource agrees to furnish supplementally a copy of any omitted schedules or exhibits to the SEC upon request.

**** Schedules and similar attachments to this Exhibit have been omitted pursuant to Item 601(a)(5) of Regulation S-K. The Company agrees to furnish supplementally a copy of any omitted schedule or exhibit to the U.S. Securities and Exchange Commission (the "SEC") upon request.

References made to NIPSCO filings can be found at Commission File Number 001-04125. References made to NiSource Inc. filings made prior to November 1, 2000 can be found at Commission File Number 001-09779.

ITEM 16. FORM 10-K SUMMARY

None.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, hereunto duly authorized.

NiSource Inc.
(Registrant)

Date: February 12, 2025

By: /s/ LLOYD M. YATES
Lloyd M. Yates
President, Chief Executive Officer and Director
(Principal Executive Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

/s/ LLOYD M. YATES Lloyd M. Yates	President, Chief Executive Officer, and Director (Principal Executive Officer)	Date:	February 12, 2025
/s/ SHAWN ANDERSON Shawn Anderson	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	Date:	February 12, 2025
/s/ GUNNAR J. GODE Gunnar J. Gode	Vice President and Chief Accounting Officer (Principal Accounting Officer)	Date:	February 12, 2025
/s/ KEVIN T. KABAT Kevin T. Kabat	Chairman of the Board	Date:	February 12, 2025
/s/ PETER A. ALTABEF Peter A. Altabef	Director	Date:	February 12, 2025
/s/ SONDRA L. BARBOUR Sondra L. Barbour	Director	Date:	February 12, 2025
/s/ THEODORE H. BUNTING, JR. Theodore H. Bunting, Jr.	Director	Date:	February 12, 2025
/s/ ERIC L. BUTLER Eric L. Butler	Director	Date:	February 12, 2025
/s/ DEBORAH A. HENRETTA Deborah A. Henretta	Director	Date:	February 12, 2025
/s/ DEBORAH A.P. HERSMAN Deborah A. P. Hersman	Director	Date:	February 12, 2025
/s/ WILLIAM D. JOHNSON William D. Johnson	Director	Date:	February 12, 2025
/s/ MICHAEL E. JESANIS Michael E. Jesanis	Director	Date:	February 12, 2025
/s/ CASSANDRA S. LEE Cassandra S. Lee	Director	Date:	February 12, 2025
/s/ JOHN MCAVOY John McAvoy	Director	Date:	February 12, 2025

STOCKHOLDER INFORMATION

Forward-Looking Statements

This document contains "forward-looking statements," within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). Investors and prospective investors should understand that many factors govern whether any forward-looking statement contained herein will be or can be realized. Any one of those factors could cause actual results to differ materially from those projected. These forward-looking statements include, but are not limited to, statements concerning our plans, strategies, objectives, expected performance, expenditures, recovery of expenditures through rates, stated on either a consolidated or segment basis, and any and all underlying assumptions and other statements that are other than statements of historical fact. Expressions of future goals and expectations and similar expressions, including "may," "will," "should," "could," "would," "aims," "seeks," "expects," "plans," "anticipates," "intends," "believes," "estimates," "predicts," "potential," "targets," "forecast," and "continue," reflecting something other than historical fact are intended to identify forward-looking statements. All forward-looking statements are based on assumptions that management believes to be reasonable; however, there can be no assurance that actual results will not differ materially.

Factors that could cause actual results to differ materially from the projections, forecasts, estimates and expectations discussed in this document include, among other things: our ability to execute our business plan or growth strategy, including utility infrastructure investments, or business opportunities, such as data center development and related generation sources and transmission capabilities to meet potential load growth; our ability to manage data center growth in our service territories; potential incidents and other operating risks associated with our business; our ability to work successfully with our third-party investors; our ability to adapt to, and manage costs related to, advances in technology, including alternative energy sources and changes in laws and regulations; our increased dependency on technology; impacts related to our aging infrastructure; our ability to obtain sufficient insurance coverage and whether such coverage will protect us against significant losses; the success of our electric generation strategy; construction risks and supply risks; fluctuations in demand from residential and commercial customers; fluctuations in the price of energy commodities and related transportation costs or an inability to obtain an adequate, reliable and cost-effective fuel supply to meet customer demand; our ability to attract, retain or re-skill a qualified, diverse workforce and maintain good labor relations; our ability to manage new initiatives and organizational changes; the performance and quality of third-party suppliers and service providers; our ability to manage the financial and operational risks related to achieving our carbon emission reduction goals, including our Net Zero Goal, including any future associated impact from business opportunities such as data center development as those opportunities evolve; potential cybersecurity attacks or security breaches; increased requirements and costs related to cybersecurity; the actions of activist stockholders; any damage to our reputation; the impacts of natural disasters, potential terrorist attacks or other catastrophic events; the physical impacts of climate change and the transition to a lower carbon future; our debt obligations; any changes to our credit rating or the credit rating of certain of our subsidiaries; adverse economic and capital market conditions, including increases in inflation or interest rates, recession, or changes in investor sentiment; economic regulation and the impact of regulatory rate reviews; our ability to obtain expected financial or regulatory outcomes; economic conditions in certain industries; the reliability of customers and suppliers to fulfill their payment and contractual obligations; the ability of our subsidiaries to generate cash; pension funding obligations; potential impairments of goodwill; the outcome of legal and regulatory proceedings, investigations, incidents, claims and litigation; compliance with changes in, or new interpretations of applicable laws, regulations and tariffs; the cost of compliance with environmental laws and regulations and the costs of associated liabilities; changes in tax laws or the interpretation thereof and other matters set forth in Item 1, "Business," Item 1A, "Risk Factors" and Part II, Item 7, "Management's Discussion and Analysis of Financial Condition and Results of Operations," of our Annual Report on Form 10-K for the fiscal year ended December 31, 2024, and any subsequent filings made with the Securities and Exchange Commission, some of which risks are beyond our control. In addition, the relative contributions to profitability by each business segment, and the assumptions underlying the forward- looking statements relating thereto, may change over time.

All forward-looking statements are expressly qualified in their entirety by the foregoing cautionary statements. We undertake no obligation to, and expressly disclaim any such obligation to, update or revise any forward-looking statements to reflect changed assumptions, the occurrence of anticipated or unanticipated events or changes to the future results over time or otherwise, except as required by law.

Regulation G Disclosure Statement

This document includes financial results and guidance for NiSource with respect to adjusted earnings per share, funds from operations/debt, and earnings CAGR, which are non- GAAP financial measures as defined by the Securities and Exchange Commission's (SEC) Regulation G. The company includes these measures because management believes it permits investors to view the company's performance using the same tools that management uses and to better evaluate the company's ongoing business performance. Reconciliations of historical non-GAAP financial measures to the most comparable GAAP financial measures can be found on page 8. With respect to guidance, it should be noted that there will likely be a difference between these measures and their GAAP equivalents due to various factors, including, but not limited to, fluctuations in weather, the impact of asset sales and impairments, and other unusual or infrequent items included in GAAP results. The company is not able to estimate the impact of such factors on GAAP earnings and, as such, is not providing earnings guidance on a GAAP basis. In addition, the company is not able to provide a reconciliation of its non-GAAP net operating earnings guidance or its funds from operations/debt guidance to their GAAP equivalents without unreasonable efforts.

Investor Relations
investors@nisource.com

Media Relations
media@nisource.com

Anticipated Dividend Record and Payment Dates* (NiSource Common Stock)

Record Date	Payment Date
02/03/25	02/20/25
04/30/25	05/20/25
07/31/25	08/20/25
10/31/25	11/20/25
02/03/26	02/20/26

Common Stock Dividend Declared*

On February 20, 2025, the company paid a quarterly dividend of $0.28 per share to stockholders of record as of the close of business on February 3, 2025, equivalent to $1.12 per share on an annual basis.

Stockholder Services

Questions about stockholder accounts, stock certificates, transfer of shares, dividend payments, automatic dividend reinvestment and stock purchase plan, and electronic deposit may be directed to Computershare at the following:

Computershare

c/o Shareholder Services
P.O. Box 43078
Providence, RI 02940-3078
(888) 884-7790
• TDD for Hearing Impaired: (800) 231-5469
• Foreign Stockholders: (201) 680-6578
• TDD Foreign Stockholders: (201) 680-6610
• Computershare.com/investor

*DIVIDENDS ARE SUBJECT TO BOARD APPROVAL.

Investor and Financial Information

Financial analysts and investment professionals should direct written and email inquiries to NiSource Investor Relations, 801 East 86th Avenue, Merrillville, Indiana 46410 or investors@nisource.com. Copies of NiSource's financial reports are available at NiSource.com.

Stock Listing

NiSource Inc. common stock is listed on the New York Stock Exchange under the ticker symbol "NI."

Independent Registered Public Accounting Firm

Deloitte & Touche LLP

Sustainability

Additional details on sustainability and environmental, social and governance (ESG) issues and related policies can be found under the Sustainability tab at NiSource.com.

Board of Directors

Communications with the Board of Directors may be made generally, to any director individually, to the non-management directors as a group or the lead director of the non-management group by writing to the following address:

NiSource Inc.
Attention: Board of Directors, Board Member, non-management directors or Chairman
c/o Corporate Secretary
801 East 86th Avenue
Merrillville, Indiana 46410

Corporate Governance

At NiSource.com, shareholders can view the company's corporate governance guidelines, code of business conduct, political spending policy and charters of all board-level committees. Copies of these documents are available to shareholders without charge upon written request to Corporate Secretary at the above address.

COMPANY INFORMATION

CORPORATE HEADQUARTERS
NiSource Inc.
801 E. 86th Avenue
Merrillville, Indiana 46410
(219) 647-5990
NiSource.com

NISOURCE CORPORATE SERVICES
801 E. 86th Avenue
Merrillville, Indiana 46410
(614) 460-6000

COLUMBIA GAS OF KENTUCKY
2001 Mercer Road
Lexington, Kentucky 40511
Emergency: (800) 432-9515
Customer Care: (800) 432-9345
ColumbiaGasKY.com

COLUMBIA GAS OF MARYLAND
121 Champion Way
Canonsburg, Pennsylvania 15317
Emergency: (888) 460-4332
Customer Care: (888) 460-4332
ColumbiaGasMD.com

COLUMBIA GAS OF OHIO
290 W. Nationwide Boulevard
Columbus, Ohio 43215
Emergency: (800) 344-4077
Customer Care: (800) 344-4077
ColumbiaGasOhio.com

COLUMBIA GAS OF PENNSYLVANIA
121 Champion Way
Canonsburg, Pennsylvania 15317
Emergency: (888) 460-4332
Customer Care: (888) 460-4332
ColumbiaGasPA.com

COLUMBIA GAS OF VIRGINIA
1809 Coyote Drive
Chester, Virginia 23836
Emergency: (800) 544-5606
Customer Care: (800) 543-8911
ColumbiaGasVA.com

NIPSCO
801 E. 86th Avenue
Merrillville, Indiana 46410
Customer Care: (800) 464-7726
Gas Emergency: (800) 634-3524
Electric Emergency: (800) 464-7726
NIPSCO.com

NiSource is a trademark of NiSource Inc. All other trademarks are the property of their respective owners. Further information about NiSource and its subsidiary companies can be found at NiSource.com. Information made available on our website does not constitute a part of this report.

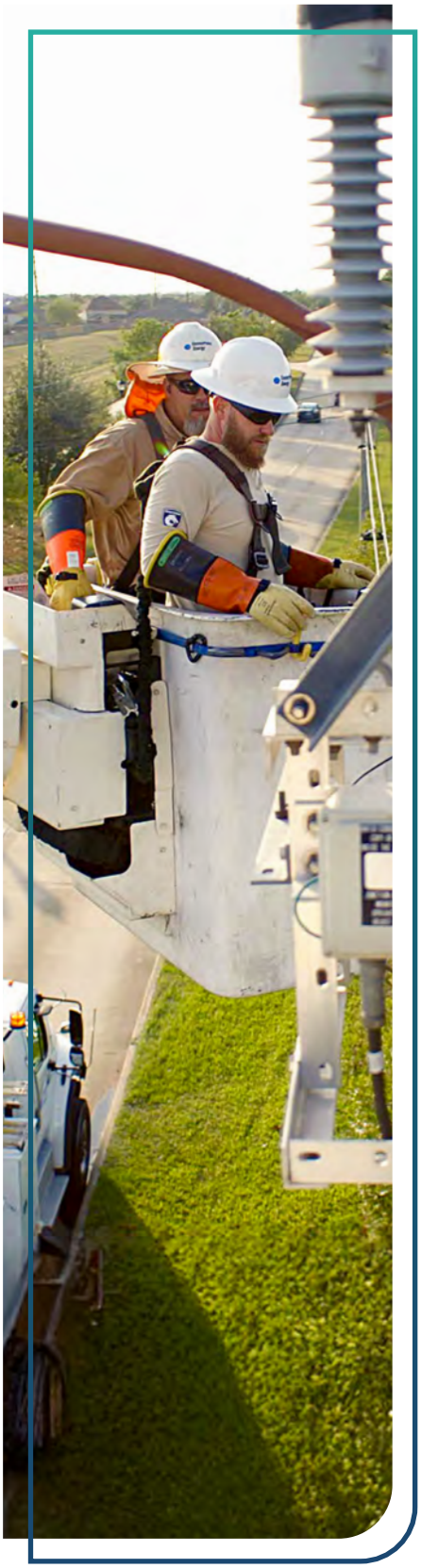
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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

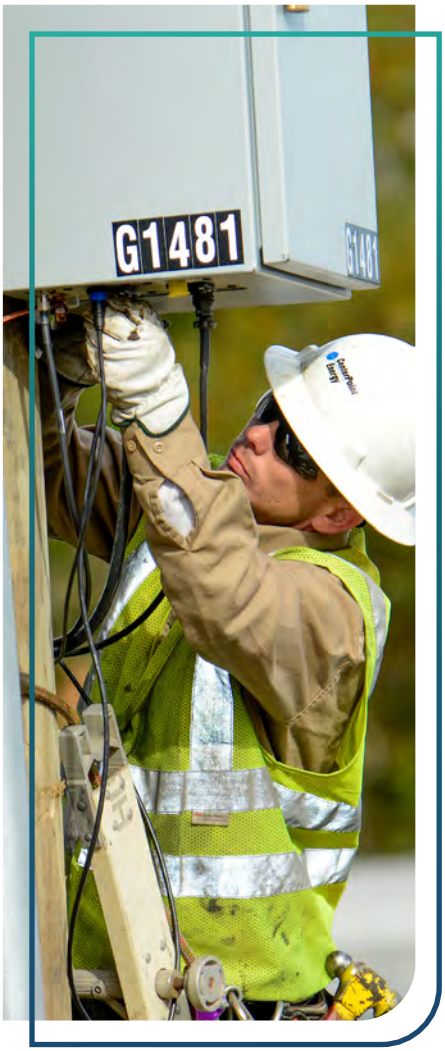
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

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

Exhibit 79
CenterPoint 2024 Annual Report







2024 Annual Report

CenterPoint® Energy

Dear Fellow Shareholders,

At CenterPoint Energy, we understand there is no greater privilege than serving the millions of people who receive electric and natural gas service from us in the thousands of cities and communities across our service territories in Texas, Indiana, Louisiana, Minnesota, Mississippi and Ohio. Our nearly 9,000 coworkers rise to the occasion each day to provide vital services that enable everyday life, drive economic development and growth, and provide for secure communities.

Our customer focus grew in prominence in 2024 as we worked to regain trust in our Greater Houston service area following multiple unprecedented weather events which impacted electric service to a significant number of the 2.8 million homes and businesses we serve. We held ourselves accountable to address the feedback we received from our numerous stakeholders.

In the second half of 2024, we accelerated our investments in resiliency and began executing an action plan to **build the most resilient coastal grid in the nation**.

This plan outlines dozens of resiliency measures that are designed to strengthen tens of thousands of miles of our transmission and distribution system, deploy additional automation, and increase situational awareness as we work to improve the customer experience for those that live and work in higher-risk areas.

Nearly

9,000

coworkers rise to the occasion each day

Serving more than

7 million

homes and businesses with natural gas and electricity



Phillip R. Smith, Independent Chair of the Board and Jason P. Wells, President and CEO

Investing in our system

Over the last several years, we've worked diligently to build a more resilient electric transmission backbone and modernize our natural gas networks across our service territories. This has been mainly accomplished by executing our 10-year capital plan through 2030 that is focused on investments made in safety, resiliency, reliability and growth enablement. Going forward, we will accelerate these investments and their associated plans as we work to address the evolving needs of the customers and communities that we serve.

A more resilient electric system

Following Hurricane Beryl, which impacted the Greater Houston area, we acted with urgency, and we introduced the Greater Houston Resiliency Initiative **(GHRI)** to address stakeholder concerns and strengthen our infrastructure against extreme weather. The GHRI reflects direct feedback from the public and stakeholders. Phase one of our plan included **more than 40 critical near- and medium-term operational objectives,** which we completed in approximately 60 days.

Since then, we have been relentlessly driving our continued efforts to harden our system and improve our communications with the objective of surpassing the expectations of our customers and enhancing their experiences. We began the second phase of the GHRI in fall 2024, which includes: installing 25,000 stronger, more storm-resilient poles; deploying 4,500 more automated reliability devices that are capable of self-healing; and trimming 4,000 more miles of higher risk trees and vegetation as well as many other additional system enhancements. Our actions are on track to be completed by the beginning of the 2025 hurricane season.

While there has been noteworthy progress to date, there is still much work to be done in our pursuit of becoming the most resilient coastal grid in the country. We fully understand our customers' expectations for exceptional service and are confident we will rise to meet those expectations. To accelerate delivery on these expectations and to achieve our next phase of resiliency work in Texas, we filed our revised $5.75 billion, 2026 – 2028 Systemwide Resiliency Plan in January. The investments included in our filing represent the largest single investment in grid resiliency in our company's history.



Gas system modernization

As part of our gas system modernization program across all six states in our service territory,

we replaced more than **470 miles of pipeline** in 2024 in the cities and communities we serve.

Approximately 190 miles of the replacements were bare steel and cast iron. We expect to be essentially complete with the cast iron modernization work by the end of 2026. Additionally, we continue to leverage technology to help keep our communities and our employees safe while continuing to operate a safe system. Our Picarro Surveyor advanced leak detection surveys are designed to help identify leaks earlier and mitigate safety risks sooner. We are in the midst of our seven-year program of Intelis smart meter deployment across our gas footprint. This innovative technology will change how we interact with our customers and better provide for their energy needs. In 2024, we installed more than 250,000 gas smart meters, allowing us to reach the milestone of more than 890,000 meters installed since our program began. CenterPoint is among the national leaders in Intelis gas smart meter deployment.

Results delivered



We reported full year 2024 earnings of $1.58 per diluted share on a GAAP basis and $1.62 on a non-GAAP basis, which represents an 8% growth rate year over year. This is our fourth consecutive year of meeting or exceeding financial expectations. This track record of consistent earnings growth over the last four years is top decile among our peers. For 2025, we are targeting non-GAAP EPS of $1.74 - $1.76, which, at its midpoint, would represent 8% growth from our 2024 non-GAAP results.[1]

We invested $3.8 billion of capital in 2024, excluding storm costs, as we continue to execute on our now $47.5 billion, 10-year capital investment plan which runs through 2030. During 2024, we increased our previous $44.5 billion capital investment plan by $3 billion to further support electric resiliency investments included in our Systemwide Resiliency Plan. With this increase in our customer-focused investments, we anticipate that our enterprise rate base annual growth rate will be approximately 10% through the balance of this decade.

Regulatory

Over the last 18 months, we've filed five base rate cases in four of the states we serve. The constructive settlements of four of those cases represent 80% of our enterprise rate base, which gives clear line of sight to financial execution over the next four years.

Filed

5

base rate cases in four of the states we serve

That execution is driven by regulatory mechanisms that allow for over 80% of our expected 10-year capital plan to be recoverable through interim capital recovery filings. The remaining rate case in Ohio will continue through 2025, and we'll work with stakeholders toward a constructive outcome.

Financing transactions

We are still on track to receive nearly $3 billion of proceeds in 2025 as we continue to finance our customer-driven investments.

In Texas, we are making progress towards securitizing approximately $1.6 billion of associated storm costs incurred through two regulatory filings under the existing state construct. Given the precedent in the state, we anticipate receiving proceeds for storm related securitization filings by year end 2025, which should be seen as a credit supportive action.

Additionally, we are on track to receive the anticipated $1.2 billion of gross sales proceeds from our Louisiana and Mississippi natural gas business divestiture by the end of the first quarter of 2025.

We are appreciative of the work our teams have performed, facilitating the transaction while enabling the seamless transition of both the Louisiana and Mississippi customers and our workforce. We would like to thank those employees joining Delta Utilities for their service to our customers and our company, and we wish them much success.

[1] ***Note:*** *Disclaimers regarding forward-looking statements, our net zero and greenhouse gas emissions reduction goals and non-GAAP financial metrics, including a reconciliation of 2023 and 2024 non-GAAP measures to the nearest GAAP metrics and information about forward-looking 2025 non-GAAP measures (including inability to present a reconciliation to the nearest GAAP metrics), are found in the Investor Information section of the report.*

Continued and sustained growth

There has never been a better time to be part of this industry because of the long-term economic growth trajectory and increased energy needs we see across our states, especially in Texas and specifically the Greater Houston region.

It is our privilege to serve one of the fastest growing regions in the United States with an **expected peak load increase of nearly 50%** in the Houston area through 2031.

We expect that this growth from 21 GW to 31 GW will be powered by a diverse set of economic drivers, such as new data centers and logistics industry electrification. We believe this peak load growth will provide incremental capex tailwinds to an already industry-leading plan.

Houston is home to the largest medical complex in the world, and it will only continue to grow. It continues to expand its offerings for patients who come from all over the globe for treatment and pioneer medical innovation and medical manufacturing.



The Greater Houston region is, and will continue to be, at the center for energy refining and energy exports. As the global energy mix continues to evolve, whether it be LNG, hydrogen or something else, we believe that Houston will play a central role in the development and exporting of that energy. This expected growth is yet another tailwind in what we continue to believe is one of the most tangible long-term growth stories in the industry.

Our growth story is one that includes $47.5 billion of capital investments across multiple states and growing non-GAAP EPS at the mid-to-high end of the 6% to 8% range annually, through 2030. We also expect to grow dividends per share in line with earnings growth over this same period of time.

Looking ahead

It's an exciting time to be a part of CenterPoint Energy as we set our sights on the future and the opportunities that await our company, our states and our customers. We have a compelling resiliency and growth story, driven by a committed and accountable workforce, who share an unrelenting dedication to the pursuit and achievement of positive outcomes for all our stakeholders. We extend our gratitude to you, our shareholders, for the trust you continue to place in CenterPoint Energy, our employees, our leadership team and our Board of Directors. We appreciate your support and confidence, and together we will continue to build a resilient, innovative and successful company that meets the energy needs of tomorrow.

Sincerely,



Jason P. Wells
President and
Chief Executive Officer



Phillip R. Smith
Independent Chair
of the Board of Directors

Houston Electric

~2% customer growth realized in 2024, adding more than 54,000 metered customers

Greater Houston Resiliency Initiative (GHRI) Phase 1 **completed ahead of schedule**; Phase 2 currently underway through June 1, 2025

Total of **22,114 structures hardened** between transmission and distribution

Conducted **advanced aerial imagery data capture to support advanced vegetation management**, including LiDAR, High Resolution Imagery and Hyperspectral

Developed **damage prediction-based models** to forecast crew requirements, staging sites and temporary generation locations

Interconnected **5,352 MW of transmission generation** and **216 MW of distribution generation**

Indiana Electric

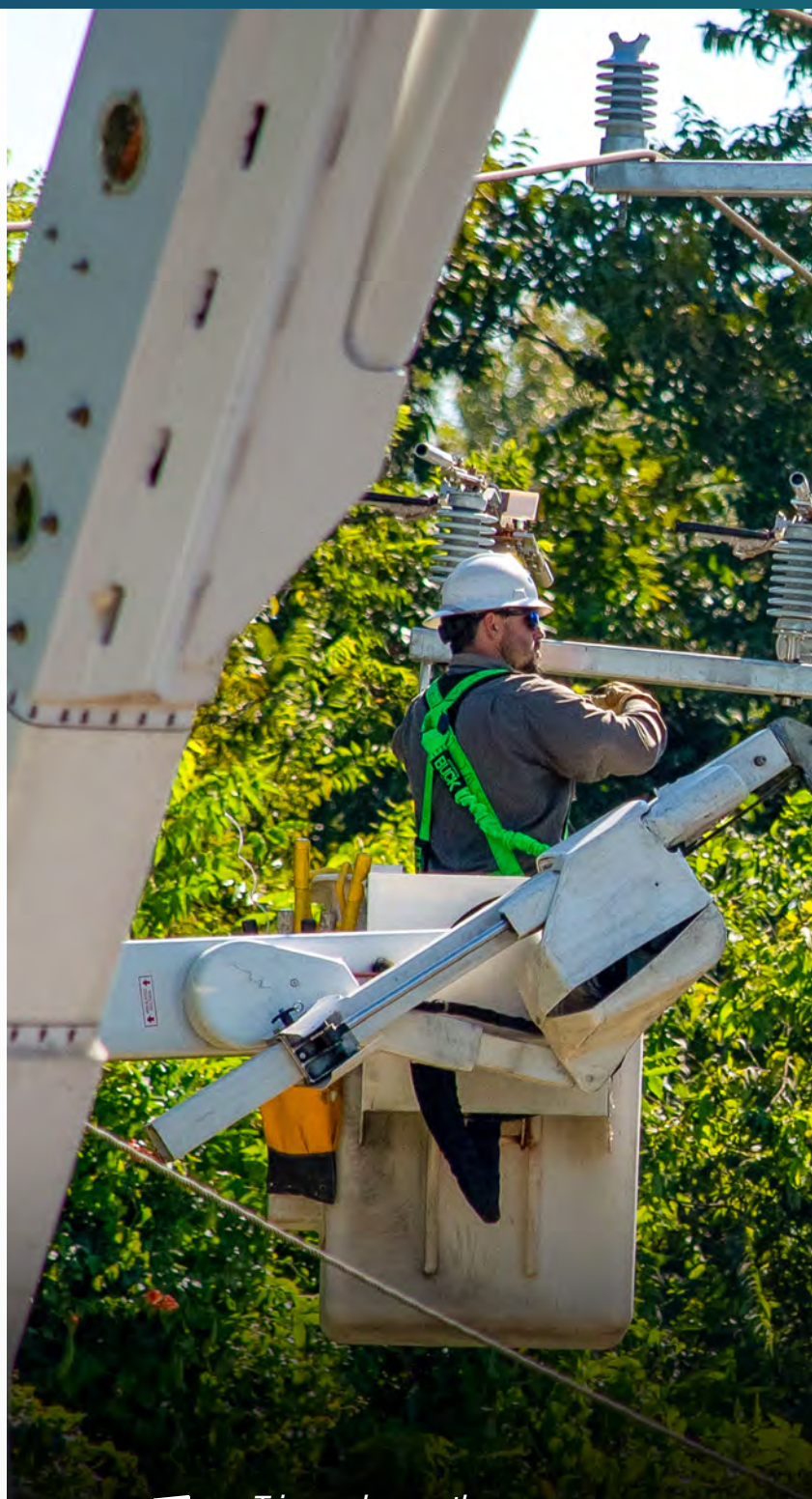
Added 914 metered customers, resulting in 0.5% customer growth

Executed the first year of its five-year distribution, transmission, and substation modernization plan, **investing an additional $73 million** in 2024

- 31 automated devices installed
- 252 transmission structures replaced
- 2,078 distribution structures replaced

Executed and received Indiana Utility Regulatory Commission (IURC) approval for an Illinois-based **147 MW wind purchased power agreement** (PPA)

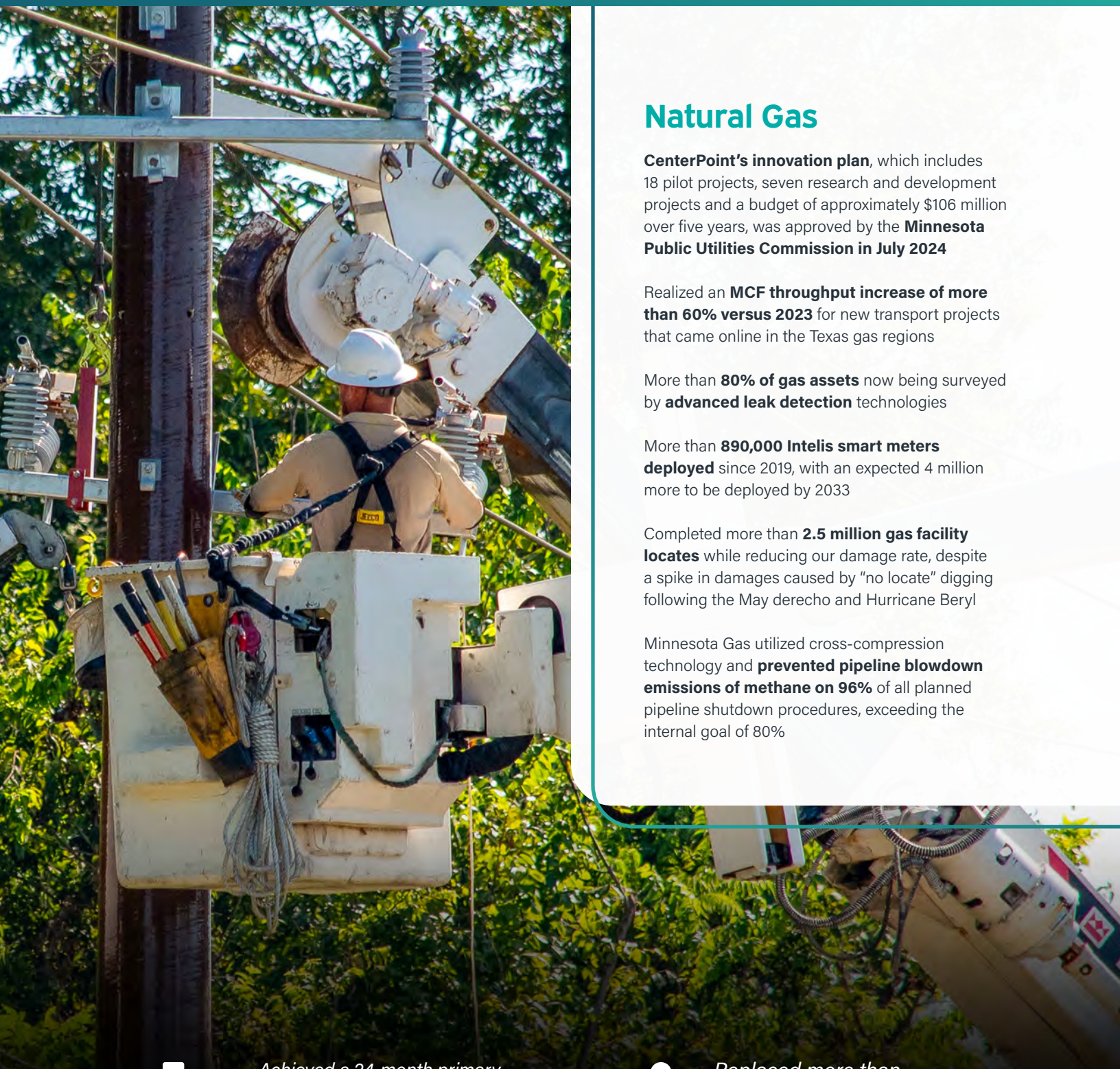
Construction continues on A.B. Brown combustion turbines (460 MW) and Posey Solar (191 MW), with **expected commercial operation date in mid-2025**



Trimmed more than

5.7K line miles of vegetation in Greater Houston

420 line miles of vegetation in Indiana



Natural Gas

CenterPoint's innovation plan, which includes 18 pilot projects, seven research and development projects and a budget of approximately $106 million over five years, was approved by the **Minnesota Public Utilities Commission in July 2024**

Realized an **MCF throughput increase of more than 60% versus 2023** for new transport projects that came online in the Texas gas regions

More than **80% of gas assets** now being surveyed by **advanced leak detection** technologies

More than **890,000 Intelis smart meters deployed** since 2019, with an expected 4 million more to be deployed by 2033

Completed more than **2.5 million gas facility locates** while reducing our damage rate, despite a spike in damages caused by "no locate" digging following the May derecho and Hurricane Beryl

Minnesota Gas utilized cross-compression technology and **prevented pipeline blowdown emissions of methane on 96%** of all planned pipeline shutdown procedures, exceeding the internal goal of 80%

Achieved a 24-month primary
emergency response time deduction of
7.5%

Replaced more than
420
pipeline miles through modernization projects

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

(Mark One)

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

FOR THE FISCAL YEAR ENDED DECEMBER 31, 2024

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 number	Registrant, State or Other Jurisdiction of Incorporation or Organization Address of Principal Executive Offices, Zip Code and Telephone Number	I.R.S. Employer Identification No.
1-31447	**CenterPoint Energy, Inc.** **(a Texas corporation)** **1111 Louisiana** **Houston, Texas 77002** **(713) 207-1111**	74-0694415
1-3187	**CenterPoint Energy Houston Electric, LLC** **(a Texas limited liability company)** **1111 Louisiana** **Houston, Texas 77002** **(713) 207-1111**	22-3865106
1-13265	**CenterPoint Energy Resources Corp.** **(a Delaware corporation)** **1111 Louisiana** **Houston, Texas 77002** **(713) 207-1111**	76-0511406

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

Registrant	Title of each class	Trading symbol(s)	Name of each exchange on which registered
CenterPoint Energy, Inc.	Common Stock, $0.01 par value	CNP	New York Stock Exchange
			NYSE Chicago
CenterPoint Energy Houston Electric, LLC	6.95% General Mortgage Bonds due 2033	n/a	New York Stock Exchange
CenterPoint Energy Resources Corp.	6.625% Senior Notes due 2037	n/a	New York Stock Exchange

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

None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

CenterPoint Energy, Inc.	Yes ☑	No ☐
CenterPoint Energy Houston Electric, LLC	Yes ☑	No ☐
CenterPoint Energy Resources Corp.	Yes ☑	No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

CenterPoint Energy, Inc.	Yes ☐	No ☑
CenterPoint Energy Houston Electric, LLC	Yes ☐	No ☑
CenterPoint Energy Resources Corp.	Yes ☐	No ☑

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.

CenterPoint Energy, Inc.	Yes ☑	No ☐
CenterPoint Energy Houston Electric, LLC	Yes ☑	No ☐
CenterPoint Energy Resources Corp.	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).

CenterPoint Energy, Inc.	Yes ☑	No ☐
CenterPoint Energy Houston Electric, LLC	Yes ☑	No ☐
CenterPoint Energy Resources Corp.	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.

	Large accelerated filer	Accelerated filer	Non-accelerated filer	Smaller reporting company	Emerging growth company
CenterPoint Energy, Inc.	☑	☐	☐	☐	☐
CenterPoint Energy Houston Electric, LLC	☐	☐	☑	☐	☐
CenterPoint Energy Resources Corp.	☐	☐	☑	☐	☐

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 Act. ☐

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☑

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements.

CenterPoint Energy, Inc.	☐
CenterPoint Energy Houston Electric, LLC	☐
CenterPoint Energy Resources Corp.	☐

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240.10D-1(b).

CenterPoint Energy, Inc.	☐
CenterPoint Energy Houston Electric, LLC	☐
CenterPoint Energy Resources Corp.	☐

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

CenterPoint Energy, Inc.	Yes ☐	No ☑
CenterPoint Energy Houston Electric, LLC	Yes ☐	No ☑
CenterPoint Energy Resources Corp.	Yes ☐	No ☑

The aggregate market values of the voting stock held by non-affiliates of the Registrants as of June 30, 2024 are as follows:

CenterPoint Energy, Inc. (using the definition of beneficial ownership contained in Rule 13d-3 promulgated pursuant to Securities Exchange Act of 1934 and excluding shares held by directors and executive officers)	$19,797,614,936
CenterPoint Energy Houston Electric, LLC	None
CenterPoint Energy Resources Corp.	None

Indicate the number of shares outstanding of each of the issuers' classes of common stock as of February 10, 2025:

CenterPoint Energy, Inc.	651,729,244	shares of common stock outstanding, excluding 166 shares held as treasury stock
CenterPoint Energy Houston Electric, LLC	1,000	common shares outstanding, all held by Utility Holding, LLC, a wholly-owned subsidiary of CenterPoint Energy, Inc.
CenterPoint Energy Resources Corp.	1,000	shares of common stock outstanding, all held by Utility Holding, LLC, a wholly-owned subsidiary of CenterPoint Energy, Inc.

CenterPoint Energy Houston Electric, LLC and CenterPoint Energy Resources Corp. meet the conditions set forth in general instruction I(1)(a) and (b) of Form 10-K and are therefore filing this Form 10-K with the reduced disclosure format specified in General Instruction I(2) of Form 10-K.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the definitive proxy statement relating to the 2025 Annual Meeting of Shareholders of CenterPoint Energy, which will be filed with the Securities and Exchange Commission within 120 days of December 31, 2024, are incorporated by reference in Item 10, Item 11, Item 12, Item 13 and Item 14 of Part III of this Form 10-K.

TABLE OF CONTENTS

PART I

		Page
Item 1.	Business	1
Item 1A.	Risk Factors	18
Item 1B.	Unresolved Staff Comments	43
Item 1C.	Cybersecurity	43
Item 2.	Properties	45
Item 3.	Legal Proceedings	48
Item 4.	Mine Safety Disclosures	48
	PART II	
Item 5.	Market for Registrants' Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities	48
Item 6.	[Reserved]	49
Item 7.	Management's Discussion and Analysis of Financial Condition and Results of Operations	49
Item 7A.	Quantitative and Qualitative Disclosures About Market Risk	88
Item 8.	Financial Statements and Supplementary Data	91
Item 9.	Changes in and Disagreements with Accountants on Accounting and Financial Disclosure	181
Item 9A.	Controls and Procedures	181
Item 9B.	Other Information	184
Item 9C.	Disclosure Regarding Foreign Jurisdictions that Prevent Inspections	184
	PART III	
Item 10.	Directors, Executive Officers and Corporate Governance	184
Item 11.	Executive Compensation	184
Item 12.	Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters	184
Item 13.	Certain Relationships and Related Transactions, and Director Independence	184
Item 14.	Principal Accounting Fees and Services	184
	PART IV	
Item 15.	Exhibits and Financial Statement Schedules	186
Item 16.	Form 10-K Summary	186

GLOSSARY

AFUDC	Allowance for funds used during construction
AGC	Alcoa Generating Corporation, a subsidiary of Alcoa, Inc.
AI	Artificial intelligence
ALJ	Administrative Law Judge
AMAs	Asset Management Agreements
AMS	Advanced Metering System
Arevon	Arevon Energy, Inc., which was formed through the combination of Capital Dynamics, Inc.'s U.S. Clean Energy Infrastructure business unit and Arevon Asset Management
ARO	Asset retirement obligation
AROK Asset Purchase Agreement	Asset Purchase Agreement, dated as of April 29, 2021, by and between CERC Corp. and Southern Col Midco, LLC, a Delaware limited liability company and an affiliate of Summit Utilities, Inc.
ARP	Alternative revenue program
ASC	Accounting Standards Codification
ASU	Accounting Standards Update
AT&T Common	AT&T Inc. common stock
ATM Forward Purchasers	Bank of America, N.A., Barclays Bank PLC, Citibank, N.A., Goldman Sachs & Co. LLC, JPMorgan Chase Bank, National Association, Mizuho Markets Americas LLC, MUFG Securities EMEA plc and Royal Bank of Canada
ATM Forward Sellers	BofA Securities, Inc. Barclays Capital Inc., Citigroup Global Markets Inc., Goldman Sachs & Co. LLC, J.P. Morgan Securities LLC, Mizuho Securities USA LLC, MUFG Securities Americas Inc. and RBC Capital Markets, LLC
ATM Managers	BofA Securities, Inc., Barclays Capital Inc., Citigroup Global Markets Inc., Goldman Sachs & Co. LLC, J.P. Morgan Securities LLC, Mizuho Securities USA LLC, MUFG Securities Americas Inc. and RBC Capital Markets, LLC
August Junior Subordinated Notes	Junior Subordinated Series A Notes and Junior Subordinated Series B Notes
Bcf	Billion cubic feet
Board	CenterPoint Energy's Board of Directors
Bond Companies	Bond Company IV and Restoration Bond Company, each a wholly-owned, bankruptcy remote entity formed solely for the purpose of purchasing and owning transition or system restoration property through the issuance of Securitization Bonds
Bond Company IV	CenterPoint Energy Transition Bond Company IV, LLC, a wholly-owned subsidiary of Houston Electric
BTA	Build Transfer Agreement
CAMT	Corporate Alternative Minimum Tax
CARES Act	Coronavirus Aid, Relief, and Economic Security Act
CCN	Certificate of Convenience and Necessity
CCR	Coal Combustion Residuals
CECA	Clean Energy Cost Adjustment
CEIP	CenterPoint Energy Intrastate Pipelines, LLC, a wholly-owned subsidiary of CERC Corp.
CenterPoint Energy	CenterPoint Energy, Inc., and its subsidiaries
CenterPoint Energy Credit Agreement	Second Amended and Restated Credit Agreement, dated December 6, 2022, by and among CenterPoint Energy, as borrower, JPMorgan Chase Bank, N.A., as administrative agent, the financial institutions as bank parties thereto and the other parties thereto.
CenterPoint Energy Extension Agreement	Extension Agreement to the CenterPoint Energy Credit Agreement, dated January 29, 2025, by and among CenterPoint Energy, JPMorgan Chase Bank, N.A., as administrative agent, and the banks party thereto
CEOH	Vectren Energy Delivery of Ohio, LLC, doing business as CenterPoint Energy Ohio, which converted its corporate structure from Vectren Energy Delivery of Ohio, Inc. to an Ohio limited liability company on June 13, 2022, formerly a wholly-owned subsidiary of Vectren, acquired by CERC on June 30, 2022
CEP	Capital Expenditure Program
CERC	CERC Corp., together with its subsidiaries
CERC Credit Agreement	Second Amended and Restated Credit Agreement, dated December 6, 2022, by and among CERC, as borrower, Wells Fargo Bank, National Association, as administrative agent, the financial institutions as bank parties thereto and the other parties thereto

CERC Extension Agreement	Extension Agreement to the CERC Credit Agreement, dated January 29, 2025, by and among CERC, Wells Fargo Bank, National Association, as administrative agent, and the banks party thereto
CERC Corp.	CenterPoint Energy Resources Corp.
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended
Change in Control Plan	CenterPoint Energy Change in Control Plan (as amended and restated effective May 1, 2017)
Charter Common	Charter Communications, Inc. common stock
CIP	Conservation Improvement Program
CNP Midstream	CenterPoint Energy Midstream, Inc., a wholly-owned subsidiary of CenterPoint Energy
Code	The Internal Revenue Code of 1986, as amended
CODM	Chief Operating Decision Maker
Common Stock	CenterPoint Energy, Inc. common stock, par value $0.01 per share
Convertible Notes	CenterPoint Energy's 4.25% Convertible Senior Notes due 2026
Convertible Notes Indenture	Indenture dated as of August 4, 2023 by and between CenterPoint Energy and The Bank of New York Mellon Trust Company, National Association, as trustee, as supplemented
COVID-19	Novel coronavirus disease 2019, and any mutations or variants thereof, and related global outbreak that was subsequently declared a pandemic by the World Health Organization
CPCN	Certificate of public convenience and necessity
COVID-19 ERP	COVID-19 Electricity Relief Program
Credit Agreements	The CenterPoint Energy Credit Agreement, Houston Electric Credit Agreement, CERC Credit Agreement and SIGECO Credit Agreement
CSIA	Compliance and System Improvement Adjustment
DA	Distribution Automation
DCRF	Distribution Cost Recovery Factor
DOC	U.S. Department of Commerce
DOT	U.S. Department of Transportation
DRR	Distribution Replacement Rider
DSMA	Demand Side Management Adjustment
Dth	Dekatherms
ECA	Environmental Cost Adjustment
EDF Renewables	EDF Renewables Development, Inc.
EDIT	Excess deferred income taxes
EECR	Energy Efficiency Cost Recovery
EECRF	Energy Efficiency Cost Recovery Factor
EEFC	Energy Efficiency Funding Component
EEFR	Energy Efficiency Funding Rider
ELG	Effluent Limitation Guidelines
EIA	U.S. Energy Information Administration
Energy Systems Group	Energy Systems Group, LLC, previously a wholly-owned subsidiary of Vectren
Energy Transfer	Energy Transfer LP, a Delaware limited partnership
Energy Transfer Common Units	Energy Transfer common units, representing limited partner interests in Energy Transfer
Energy Transfer GP	LE GP, LLC, a Delaware limited liability company and sole general partner of Energy Transfer
Energy Transfer Series G Preferred Units	Energy Transfer Series G Fixed-Rate Reset Cumulative Redeemable Perpetual Preferred Units, representing limited partner interests in Energy Transfer
EPA	Environmental Protection Agency
EPC	Engineering, Procurement and Construction
Equity Distribution Agreement	Equity Distribution Agreement, dated as of January 10, 2024, by and between CenterPoint Energy, the ATM Managers, the ATM Forward Purchasers and the ATM Forward Sellers
Equity Purchase Agreement	Equity Purchase Agreement, dated as of May 21, 2023, by and between Vectren Energy Services and ESG Holdings Group

GLOSSARY

ERCOT	Electric Reliability Council of Texas
ERCOT ISO	ERCOT Independent System Operator
ERISA	Employee Retirement Income Security Act of 1974
ERO	Electric Reliability Organization
ESG Holdings Group	ESG Holdings Group, LLC a Delaware limited liability company, and an affiliate of Oaktree Capital Management
ESPC	Energy Savings Performance Contract
Exchange Act	The Securities Exchange Act of 1934, as amended
Extension Agreements	The CenterPoint Energy Extension Agreement, Houston Electric Extension Agreement, CERC Extension Agreement and SIGECO Extension Agreement
FAC	Fuel Adjustment Clause
FASB	Financial Accounting Standards Board
February 2021 Winter Storm Event	The extreme and unprecedented winter weather event in February 2021 (also known as Winter Storm Uri) resulting in electricity generation supply shortages, including in Texas, and natural gas supply shortages and increased wholesale prices of natural gas in the United States, primarily due to prolonged freezing temperatures.
FERC	Federal Energy Regulatory Commission
Fitch	Fitch Ratings, Inc.
Form 10-K	Annual Report on Form 10-K
FPA	Federal Power Act
GAAP	Generally Accepted Accounting Principles
General Mortgage	General Mortgage Indenture, dated as of October 10, 2002, between CenterPoint Energy Houston Electric, LLC and JPMorgan Chase Bank, as Trustee, as supplemented from time to time
GHG	Greenhouse gases
GHRI	The Greater Houston Resiliency Initiative, which was announced by Houston Electric in August 2024 and includes targeted actions to improve the resiliency of Houston Electric's electric grid, as well as improve customer communications and community partnerships
GRIP	Gas Reliability Infrastructure Program
GWh	Gigawatt-hours
HLPSA	Hazardous Liquid Pipeline Safety Act of 1979
Houston Electric	CenterPoint Energy Houston Electric, LLC and its subsidiaries
Houston Electric Credit Agreement	Second Amended and Restated Credit Agreement, dated December 6, 2022, by and among Houston Electric, as borrower, Mizuho Bank, Ltd., as administrative agent, the financial institutions as bank parties thereto and the other parties thereto
Houston Electric Extension Agreement	Extension Agreement to the Houston Electric Credit Agreement, dated January 29, 2025, by and among Houston Electric, Mizuho Bank, Ltd., as administrative agent, and the banks party thereto
Hurricane Beryl	The powerful and destructive storm that made landfall in Texas on July 8, 2024 and caused widespread damage to Houston Electric's electric delivery system
HVAC	Heating, ventilation and air conditioning
IAS	International Accounting Standards
IBEW	International Brotherhood of Electrical Workers
ICPA	Inter-Company Power Agreement
IDEM	Indiana Department of Environmental Management
IG	Intelligent Grid
Indiana Electric	Operations of SIGECO's electric transmission and distribution services, and includes its power generating and wholesale power operations
Indiana Gas	Indiana Gas Company, Inc., a wholly-owned subsidiary of CERC Corp.
Indiana North	Gas operations of Indiana Gas
Indiana South	Gas operations of SIGECO
Indiana Utilities	Indiana Electric, Indiana North and Indiana South, collectively
Infrastructure Services	Provided underground pipeline construction and repair services through VISCO and its wholly-owned subsidiaries, Miller Pipeline, LLC and Minnesota Limited, LLC
IRA	Inflation Reduction Act of 2022

GLOSSARY

IRP	Integrated Resource Plan
IRS	Internal Revenue Service
IURC	Indiana Utility Regulatory Commission
Junior Subordinated Notes	Junior Subordinated Series A Notes, Junior Subordinated Series B Notes and Junior Subordinated Series C Notes
Junior Subordinated Notes Indenture	Junior Subordinated Indenture, dated as of August 14, 2024, between CenterPoint Energy and The Bank of New York Mellon Trust Company, National Association, as trustee, as supplemented
Junior Subordinated Series A Interest Reset Period	Each five-year period following February 15, 2030
Junior Subordinated Series A Notes	7.000% Fixed-to-Fixed Reset Rate Junior Subordinated Notes, Series A, due 2055
Junior Subordinated Series B Interest Reset Period	Each five-year period following February 15, 2035
Junior Subordinated Series B Notes	6.850% Fixed-to-Fixed Reset Rate Junior Subordinated Notes, Series B, due 2055
Junior Subordinated Series C Interest Reset Period	Each five-year period following May 15, 2030
Junior Subordinated Series C Notes	6.700% Fixed-to-Fixed Reset Rate Junior Subordinated Notes, Series C, due 2055
kV	Kilovolt
LAMS Asset Purchase Agreement	Asset Purchase Agreement, dated as of February 19, 2024, by and among CERC Corp. and the LAMS Buyers
LAMS Buyers	Delta North Louisiana Gas Company, LLC, a Delaware limited liability company, Delta South Louisiana Gas Company, LLC, a Delaware limited liability company, Delta Mississippi Gas Company, LLC, a Delaware limited liability company, and Delta Energy Resources, LLC, a Delaware limited liability company
LDC	Local Distribution Company
LIBOR	London Interbank Offered Rate
LNG	Liquefied natural gas
Load Shed	Curtailing the amount of electricity a TDU can transmit and distribute to its customers
LPSC	Louisiana Public Service Commission
LTIPs	Long-term incentive plans
May 2024 Storm Events	The sudden and destructive severe weather events in May 2024 that included hurricane-like winds and tornadoes and resulted in widespread damage to Houston Electric's electric delivery system
MCRA	MISO Cost and Revenue Adjustment
M&DOT	Mortgage and Deed of Trust, dated November 1, 1944, between Houston Lighting and Power Company and Chase Bank of Texas, National Association (formerly, South Texas Commercial National Bank of Houston), as Trustee, as amended and supplemented
MGP	Manufactured gas plant
MISO	Midcontinent Independent System Operator
MMBtu	One million British thermal units
MMcf	Million cubic feet
Moody's	Moody's Investors Service, Inc.
MP2017	2017 pension mortality improvement scale developed annually by the Society of Actuaries
MP2018	2018 pension mortality improvement scale developed annually by the Society of Actuaries
MP2019	2019 pension mortality improvement scale developed annually by the Society of Actuaries
MPSC	Mississippi Public Service Commission
MPUC	Minnesota Public Utilities Commission
Mva	Megavolt amperes
MW	Megawatts
NAV	Net asset value
Natural Gas	Natural gas distribution businesses
NECA	National Electrical Contractors Association
NERC	North American Electric Reliability Corporation
NGA	Natural Gas Act of 1938
NGLs	Natural gas liquids

NGPA	Natural Gas Policy Act of 1978
NGPSA	Natural Gas Pipeline Safety Act of 1968
NOLs	Net operating losses
NRG	NRG Energy, Inc.
NYSE	New York Stock Exchange
OPEIU	Office & Professional Employees International Union
Oriden	Oriden LLC
Origis	Origis Energy USA Inc.
OUCC	Indiana Office of Utility Consumer Counselor
OVEC	Ohio Valley Electric Corporation
PHMSA	Pipeline and Hazardous Materials Safety Administration
PIPES Act	Protecting Our Infrastructure of Pipelines and Enhancing Safety Act of 2020
Posey Solar	Posey Solar, LLC, a Delaware limited liability company
PPA	Power purchase agreement
PRPs	Potentially responsible parties
PTCs	Production Tax Credits
PUCO	Public Utilities Commission of Ohio
PUCT	Public Utility Commission of Texas
Railroad Commission	Railroad Commission of Texas
RCRA	Resource Conservation and Recovery Act of 1976
Registrants	CenterPoint Energy, Inc., CenterPoint Energy Houston Electric, LLC and CenterPoint Energy Resources Corp., collectively
Reliant Energy	Reliant Energy, Incorporated
REP	Retail electric provider
Restoration Bond Company	CenterPoint Energy Restoration Bond Company, LLC, a wholly-owned subsidiary of Houston Electric
Restructuring	CERC Corp.'s common control acquisition of Indiana Gas and VEDO from VUH on June 30, 2022
ROE	Return on equity
ROU	Right of use
RRA	Rate Regulation Adjustment
RSP	Rate Stabilization Plan
S&P	S&P Global Ratings, a division of S&P Global Inc.
Scope 1 emissions	Direct source of GHG emissions from a company's operations
Scope 2 emissions	Indirect source of GHG emissions from a company's energy usage
Scope 3 emissions	Indirect source of GHG emissions from a company's end-users
SEC	Securities and Exchange Commission
Securitization Bonds	Transition and system restoration bonds issued by the Bond Companies and SIGECO Securitization Bonds issued by the SIGECO Securitization Subsidiary
Series A Preferred Stock	CenterPoint Energy's previously outstanding Series A Fixed-to-Floating Rate Cumulative Redeemable Perpetual Preferred Stock, par value $0.01 per share, with a liquidation preference of $1,000 per share
SIGECO	Southern Indiana Gas and Electric Company, a wholly-owned subsidiary of Vectren
SIGECO Credit Agreement	Credit Agreement, dated as of December 6, 2022, by and among SIGECO, as borrower, Wells Fargo Bank, National Association, as administrative agent, the financial institutions as banks parties thereto and the other parties thereto
SIGECO Extension Agreement	Extension Agreement to the SIGECO Credit Agreement, dated as of January 29, 2025, by and among SIGECO, Wells Fargo Bank, National Association, as administrative agent and the banks party thereto
SIGECO Securitization Bonds	SIGECO Securitization Subsidiary's Series 2023-A Senior Secured Securitization Bonds
SIGECO Securitization Subsidiary	SIGECO Securitization I, LLC, a direct, wholly-owned subsidiary of SIGECO
SOFR	Secured Overnight Financing Rate

SRC	Sales Reconciliation Component
SRP	The transmission and distribution system resiliency plan filed by Houston Electric with the PUCT on January 31, 2025, which proposes investing approximately $5.75 billion over a three-year period for transmission and distribution infrastructure, information technology and cybersecurity assets and event response capability
TBD	To be determined
TCA	Texas Consumer Association
TCJA	Tax reform legislation informally called the Tax Cuts and Jobs Act of 2017
TCOS	Transmission Cost of Service
TCRF	Transmission Cost Recovery Factor
TDSIC	Transmission, Distribution and Storage System Improvement Charge
TDU	Transmission and distribution utility
TEEEF	Assets leased or costs incurred as "temporary emergency electric energy facilities" under Section 39.918 of the Public Utility Regulatory Act, also referred to as temporary generation
Texas RE	Texas Reliability Entity
TSA	Transportation Security Administration
USW	United Steelworkers Union
UWUA	Utility Workers Union of America
Utility Holding	Utility Holding, LLC, a wholly-owned subsidiary of CenterPoint Energy
Vectren	Vectren, LLC, which converted its corporate structure from Vectren Corporation to a limited liability company on June 30, 2022, a wholly-owned subsidiary of CenterPoint Energy as of February 1, 2019, and, after the Restructuring, is held indirectly by CenterPoint Energy through Vectren Affiliated Utilities, Inc.
Vectren Energy Services	Vectren Energy Services Corporation, an Indiana corporation and a wholly-owned subsidiary of CenterPoint Energy
VEDO	Vectren Energy Delivery of Ohio, LLC, which converted its corporate structure from Vectren Energy Delivery of Ohio, Inc. to a limited liability company on June 13, 2022, formerly a wholly-owned subsidiary of Vectren, acquired by CERC on June 30, 2022
VIE	Variable interest entity
VISCO	Vectren Infrastructure Services Corporation, formerly a wholly-owned subsidiary of Vectren
Vistra Energy Corp.	Texas-based energy company focused on the competitive energy and power generation markets.
VRP	Voluntary Remediation Program
VUH	Vectren Utility Holdings, LLC, which converted its corporate structure from Vectren Utility Holdings, Inc. to a limited liability company on June 30, 2022, a wholly-owned subsidiary of Vectren
WBD Common	Warner Bros. Discovery, Inc. Series A common stock
Winter Storm Elliott	From December 21 to 26, 2022, a historic extratropical cyclone created winter storm conditions, including blizzards, high winds, snowfall and record cold temperatures across the majority of the United States and parts of Canada.
ZENS	2.0% Zero-Premium Exchangeable Subordinated Notes due 2029
ZENS-Related Securities	As of December 31, 2023 and December 31, 2022, consisted of AT&T Common, Charter Common and WBD Common
2023 Form 10-K	Annual Report on Form 10-K for the fiscal year ended December 31, 2023
2022 Annuity Purchase	The irrevocable group annuity contract purchased in December 2022 from an insurance company to transfer $138 million of CenterPoint Energy's pension plan's outstanding benefit obligation

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

From time to time the Registrants make statements concerning their expectations, beliefs, plans, objectives, goals, strategies, future events or performance and underlying assumptions and other statements that are not historical facts. These statements are "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. Actual results may differ materially from those expressed or implied by these statements. You can generally identify forward-looking statements by the words "anticipate," "believe," "continue," "could," "estimate," "expect," "forecast," "goal," "intend," "may," "objective," "plan," "potential," "predict," "projection," "should," "target," "will" or other similar words.

The Registrants have based their forward-looking statements on management's beliefs and assumptions based on information reasonably available to management at the time the statements are made. The Registrants caution you that assumptions, beliefs, expectations, intentions and projections about future events may and often do vary materially from actual results. Therefore, the Registrants cannot assure you that actual results will not differ materially from those expressed or implied by the Registrants' forward-looking statements. In this Form 10-K, unless context requires otherwise, the terms "our," "we" and "us" are used as abbreviated references to CenterPoint Energy, Inc. together with its consolidated subsidiaries, including Houston Electric, CERC and SIGECO.

Some of the factors that could cause actual results to differ from those expressed or implied by the Registrants' forward-looking statements are described under "Risk Factors" in Item 1A and "Management's Discussion and Analysis of Financial Condition and Results of Operations — Certain Factors Affecting Future Earnings" and " — Liquidity and Capital Resources — Other Matters — Other Factors That Could Affect Cash Requirements" in Item 7 of Part II of this report, which discussions are incorporated herein by reference.

You should not place undue reliance on forward-looking statements. Each forward-looking statement speaks only as of the date of the particular statement, and the Registrants undertake no obligation to update or revise any forward-looking statements.

SUMMARY OF RISK FACTORS

An investment in CenterPoint Energy's securities involves a significant degree of risk. Below is a summary of certain risk factors to consider in evaluating CenterPoint Energy as well as its Common Stock. However, this list is not exhaustive. Before investing in CenterPoint Energy, carefully consider the risk factors discussed or referenced below and in Item 1A. "Risk Factors" of this combined report on Form 10-K. If any of the risks discussed below and in Item 1A. "Risk Factors" were actually to occur, CenterPoint Energy's, Houston Electric's and CERC's business, financial condition, results of operations or cash flows could be adversely affected. In that case, CenterPoint Energy might not be able to pay dividends on its Common Stock, or the trading price of its Common Stock could decline.

Risk Factors Affecting Operations

Electric Generation, Transmission and Distribution (CenterPoint Energy and Houston Electric)

- Disruptions at power generation facilities, generation inadequacy or directives issued by regulatory authorities could cause interruptions in Houston Electric's and Indiana Electric's ability to provide transmission and distribution services and adversely affect their reputation, financial condition, results of operations and cash flows.
- Indiana Electric's execution of its generation transition plan, including its IRP, is subject to various risks, including timely recovery of capital investments and increased costs and risks related to the timing and cost of development and/or construction of new generation facilities.
- Houston Electric's receivables are primarily concentrated in a small number of REPs, and any delay or default in payments of these receivables could adversely affect Houston Electric's financial condition, results of operations and cash flows.
- Houston Electric's use of TEEEF is subject to various risks, including failure to obtain and deploy sufficient TEEEF resources, potential performance issues and allegations about Houston Electric's procurement and deployment of the resources (including the planning, execution and effectiveness of the same), regulatory and environmental requirements, and timely recovery of capital.
- The occurrence of extreme weather events, including winter storms and record hot temperatures, or other causes could lead to additional reforms to the Texas electric market, some measure of which, if implemented, could have an adverse impact on Houston Electric.

Natural Gas (CenterPoint Energy and CERC)

- Access to natural gas supplies and pipeline transmission and storage capacity are essential components of reliable service for Natural Gas' customers.
- Natural Gas is subject to fluctuations in natural gas prices, which could affect the ability of its suppliers and customers to meet their obligations or may impact its operations, which could adversely affect CERC's financial condition, results of operations and cash flows.
- Natural Gas must compete with alternate energy sources, which could result in less natural gas delivered and have an adverse impact on CenterPoint Energy's and CERC's financial condition, results of operations and cash flows.

Risk Factors Affecting Regulatory, Environmental and Legal Risks

- Rate regulation of Registrants' Electric and Natural Gas businesses may delay or deny their ability to earn an expected return and fully and timely recover their costs.
- We are involved in numerous legal proceedings, the outcomes of which are uncertain, and resolutions adverse to us could negatively affect our financial results.
- Negative opinions of CenterPoint Energy from customers, investors, legislators, regulators and creditors relating to actual or perceived system reliability, the speed of our response to service interruptions, rates, our ability to successfully execute our capital plan, media coverage and actions by third parties, could harm our reputation and have an adverse impact on our business, results of operations, cash flows and financial condition. For example, Hurricane Beryl caused severe disruptions to our operations, customers and markets in certain of our service territories and potential results arising from governmental and regulatory inquiries and investigations, as well as associated litigation, could have a material adverse impact on our financial condition, results of operations, cash flows and liquidity.
- We are subject to operational and financial risks and liabilities arising from environmental laws and regulations, including regulation of CCR, climate change legislation and certain local initiatives that seek to limit fossil fuel usage.
- CenterPoint Energy is subject to operational and financial risks and liabilities associated with its sustainability and related activities, including the implementation of and efforts to achieve its GHG emissions reduction goals.

Risk Factors Affecting Financial, Economic and Market Risks

- Disruptions to the global supply chain may lead to higher prices for goods and services and impact our operations, which could have an adverse impact on our ability to execute our capital plan and on our financial condition, results of operations and cash flows.
- If we are unable to arrange future financings on acceptable terms, our ability to finance our capital expenditures or refinance outstanding indebtedness could be limited.
- CenterPoint Energy is a holding company that derives all of its operating income from, and holds substantially all of its assets through, its subsidiaries. As a result, CenterPoint Energy depends on the performance of and distributions from its subsidiaries to meet its payment obligations and to pay dividends on its common stock, and provisions of applicable law or contractual restrictions could limit the amount of those distributions.
- If CenterPoint Energy redeems the ZENS prior to their maturity in 2029, its ultimate tax liability and redemption payments would result in significant cash payments, which would adversely impact its cash flows and liquidity. Similarly, a significant amount of exchanges of ZENS by ZENS holders could adversely impact CenterPoint Energy's cash flows and liquidity.

Risk Factors Affecting Safety and Security Risks

- The Registrants' businesses have safety risks.
- Cyberattacks, physical security breaches, acts of terrorism or other disruptions could adversely impact our reputation, financial condition, results of operations and cash flows.
- We may not be successful in our adoption, development and deployment of AI, which could adversely affect our business, reputation or financial results.

General and Other Risks

- Our revenues and results of operations are seasonal.
- Climate change and other weather and natural disaster impacts could adversely impact financial results from our businesses and our results of operations.

- We are exposed to risks related to changes in demand and energy consumption that could adversely impact financial results from our businesses and our results of operations.
- Aging infrastructure may lead to increased costs and disruptions in operations that could negatively impact our financial results.
- Our businesses will continue to have to adapt to technological change and may not be successful or may have to incur significant expenditures to adapt to technological change.

PART I

Item 1. *Business*

This combined Form 10-K is filed separately by three registrants: CenterPoint Energy, Inc., CenterPoint Energy Houston Electric, LLC and CenterPoint Energy Resources Corp. Information contained herein relating to any individual registrant is filed by such registrant solely on its own behalf. Each registrant makes no representation as to information relating exclusively to the other registrants or the subsidiaries of CenterPoint Energy, Inc. other than itself or its subsidiaries. Except as discussed in Note 12 to the consolidated financial statements, no registrant has an obligation in respect of any other registrant's debt securities, and holders of such debt securities should not consider the financial resources or results of operations of any registrant other than the obligor in making a decision with respect to such securities.

The discussion of CenterPoint Energy's consolidated financial information includes the financial results of Houston Electric and CERC. Where appropriate, information relating to a specific registrant has been segregated and labeled as such. Unless the context indicates otherwise, specific references to Houston Electric and CERC also pertain to CenterPoint Energy. In this combined Form 10-K, the terms "our," "we" and "us" are used as abbreviated references to CenterPoint Energy, Inc. together with its consolidated subsidiaries, including Houston Electric and CERC, unless stated otherwise.

OUR BUSINESS

Overview

CenterPoint Energy is a public utility holding company. CenterPoint Energy's operating subsidiaries own and operate electric transmission, distribution and generation facilities and natural gas distribution systems.

As of December 31, 2024, CenterPoint Energy's indirect, wholly-owned subsidiaries included:

- Houston Electric, which provides electric transmission service to transmission service customers in the ERCOT region and distribution service to REPs serving the Texas Gulf Coast area that includes the city of Houston. Bond Company IV is a wholly-owned, bankruptcy-remote entity formed solely for the purpose of purchasing and owning transition property through the issuance of Securitization Bonds;

- CERC Corp., which (i) directly owns and operates natural gas distribution systems in Louisiana, Minnesota, Mississippi and Texas, (ii) indirectly, through Indiana Gas and CEOH, owns and operates natural gas distribution systems in Indiana and Ohio, respectively, and (iii) owns and operates permanent pipeline connections through interconnects with various interstate and intrastate pipeline companies through CEIP; and

- SIGECO, which provides energy delivery services to electric and natural gas customers located in and near Evansville in southwestern Indiana and owns and operates electric generation assets to serve its electric customers and optimizes those assets in the wholesale power market.

As of December 31, 2024, CenterPoint Energy's reportable segments were Electric, Natural Gas and Corporate and Other. Houston Electric and CERC each consist of one reportable segment. For a description of CenterPoint Energy's reportable segments, see Note 16. For a discussion of net income by segment, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Results of Operations by Reportable Segment" in Item 7 of Part II of this report.

On June 30, 2023, CenterPoint Energy completed the sale of its indirect subsidiary, Energy Systems Group, to an unaffiliated third party. On February 19, 2024, CenterPoint Energy, through its subsidiary CERC Corp., entered into the LAMS Asset Purchase Agreement to sell its Louisiana and Mississippi natural gas LDC businesses. The transaction is expected to close in the first quarter of 2025. For further information, see Note 4 to the consolidated financial statements.

The Registrants' principal executive offices are located at 1111 Louisiana, Houston, Texas 77002 (telephone number: 713-207-1111).

We make available free of charge on CenterPoint Energy's Internet website, http://www.centerpointenergy.com, our annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, as soon as reasonably practicable after we electronically file such reports with, or furnish them to, the SEC. The SEC maintains an Internet website

that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC at http://www.sec.gov. Additionally, we make available free of charge on CenterPoint Energy's Internet website:

- our Code of Ethics for our Chief Executive Officer and Senior Financial Officers;
- our Ethics and Compliance Code;
- our Supplier Code of Conduct;
- our Corporate Governance Guidelines; and
- the charters of the Audit, Human Capital and Compensation, Governance, Environmental and Sustainability, and Safety and Operations committees of our Board of Directors.

Any shareholder who so requests may obtain a printed copy of any of these documents from us. Changes in or waivers of our Code of Ethics for our Chief Executive Officer and Senior Financial Officers and waivers of our Ethics and Compliance Code for directors or executive officers will be posted on our Internet website within five business days of such change or waiver and maintained for at least 12 months or timely reported on Item 5.05 of Form 8-K.

Investors should also note that we announce material financial information in SEC filings, press releases and public conference calls. Based on guidance from the SEC, we may use the investor relations section of our Internet website to communicate with our investors. It is possible that the financial and other information posted there could be deemed to be material information. Except to the extent explicitly stated herein, documents and information on our Internet website are not incorporated by reference herein.

Electric (CenterPoint Energy)

The Electric reportable segment is comprised of Houston Electric and Indiana Electric.

For information regarding the properties of the Electric reportable segment, see "Properties — Electric (CenterPoint Energy and Houston Electric)" in Item 2 of this report, which information is incorporated herein by reference.

Houston Electric (CenterPoint Energy and Houston Electric)

Houston Electric is a transmission and distribution electric utility that operates wholly within the state of Texas. Houston Electric does not make direct retail or wholesale sales of electric energy or own or operate any power generating facilities other than leased TEEEF.

Electric Transmission

On behalf of REPs, Houston Electric delivers electricity from power plants to substations, from one substation to another and to retail electric customers taking power at or above 69 kV in locations throughout Houston Electric's certificated service territory. Houston Electric constructs and maintains transmission facilities and provides transmission services under tariffs approved by the PUCT.

Electric Distribution

Houston Electric's distribution network receives electricity from the transmission grid through power distribution substations and delivers electricity for REPs in its certificated service area by carrying lower-voltage power from the substation to the retail electric customer through distribution feeders. Houston Electric's operations include construction and maintenance of distribution facilities, metering services, outage response services and call center operations. Houston Electric provides distribution services under tariffs approved by the PUCT. PUCT rules and market protocols govern the commercial operations of distribution companies and other market participants. Rates for these services are established pursuant to rate proceedings conducted before municipalities that have original jurisdiction and the PUCT.

Temporary Generation.

As allowed by a law enacted by the Texas legislature after the February 2021 Winter Storm Event and amended in 2023, Houston Electric is leasing TEEEF that can aid in restoring power to customers during certain significant power outages that are

impacting its distribution system. On December 19, 2024, Houston Electric announced a proposal to release certain of Houston Electric's TEEEF to the San Antonio area prior to the summer of 2025 for a period of up to two years, during which Houston Electric would not receive revenue or profit from ERCOT and would not charge Houston-area customers for these TEEEF units. As of December 31, 2024, Houston Electric leased 505 MW of TEEEF. For more information, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Executive Summary — Significant Events — May 2024 Storm Events and Hurricane Beryl" in Item 7 of Part II of this report, as well as Note 7 and Note 19 to the consolidated financial statements.

Bond Companies

Houston Electric has special purpose subsidiaries consisting of the Bond Companies, which it consolidates. These consolidated special purpose subsidiaries are wholly-owned, bankruptcy-remote entities that were formed solely for the purpose of purchasing and owning transition or system restoration property through the issuance of Securitization Bonds, and conducting activities incidental thereto. The Securitization Bonds issued by Bond Company IV were repaid through charges imposed on customers in Houston Electric's service territory. Restoration Bond Company repaid in full its last outstanding system restoration bonds at maturity on August 15, 2022, and was subsequently dissolved in 2024. On October 15, 2024, Bond Company IV repaid in full its last outstanding transition bonds at maturity. For further discussion of the Securitization Bonds issued by Bond Company IV and the outstanding balances as of December 31, 2024 and 2023, see Note 12 to the consolidated financial statements.

Customers

Houston Electric serves nearly all of the Houston/Galveston metropolitan area near the Texas Gulf Coast. Houston Electric's customers consist of REPs, which sell electricity to metered customers in Houston Electric's certificated service area, and municipalities, electric cooperatives and other distribution companies located outside Houston Electric's certificated service area. Each REP is licensed by, and must meet minimum creditworthiness criteria established by, the PUCT. Houston Electric does not have long-term contracts with any of its customers, but rather operates using a continuous billing cycle, with meter readings being conducted and invoices being distributed to REPs each business day. For information regarding Houston Electric's major customers, see Note 16 to the consolidated financial statements.

The table below reflects the number of REPs and metered customers in Houston Electric's service area as of December 31, 2024:

	REPs	Residential	Commercial/ Industrial	Total Customers
Texas Gulf Coast	67	2,506,284	312,059	2,818,343

Competition

There are no other electric transmission and distribution utilities in Houston Electric's service area. For another provider of transmission and distribution services to provide such services in Houston Electric's territory, it would be required to obtain a CCN from the PUCT and, depending on the location of the facilities, may also be required to obtain franchises from one or more municipalities. Houston Electric is not aware of any other party intending to enter this business in its service area at this time. Distributed generation (i.e., power generation located at or near the point of consumption) could result in a reduction of demand for Houston Electric's distribution services but has not been a significant factor to date.

Seasonality

Houston Electric's revenues are primarily derived from rates that it collects from each REP based on the amount of electricity it delivers on behalf of that REP. Houston Electric's revenues and results of operations are subject to seasonality, weather conditions and other changes in electricity usage, with revenues generally being higher during the warmer months when more electricity is used for cooling purposes.

Franchises

Houston Electric holds non-exclusive franchises from certain incorporated municipalities in its service territory. In exchange for the payment of fees, these franchises give Houston Electric the right to use the streets and public rights-of-way of these municipalities to construct, operate and maintain its transmission and distribution system and to use that system to

conduct its electric delivery business and for other purposes that the franchises permit. The terms of the franchises, with various expiration dates, typically range from 30 to 40 years.

Indiana Electric (CenterPoint Energy)

Indiana Electric consists of SIGECO's electric transmission and distribution services, including its electric generation assets and wholesale power operations. The table below reflects the number of metered customers to whom Indiana Electric supplied electric service as of December 31, 2024:

	Residential	Commercial/ Industrial	Total Customers
Southwestern Indiana	133,866	19,541	153,407

System Load

Total load and the related reserve margin at the time of the system summer peak on August 29, 2024, is presented below in MW, except for reserve margin at peak:

	2024
Total load at peak	1,062
Generating capability	720
Purchase supply (effective capacity) (1)	698
Interruptible contracts & direct load control	15
Total power supply capacity	1,433
Reserve margin at peak	35 %

(1) Indiana Electric procured bi-lateral capacity contracts starting in the 2023-2024 MISO planning year. These contracts were procured before MISO moved to a seasonal construct, which allowed several generating units to receive accreditation in the summer season that would not have received any accreditation under MISO's previous annual construct. This resulted in a reserve margin that is higher than normal in the summer, but was limited to the summer season.

The winter peak load for the 2023-2024 season of approximately 835 MW occurred on January 16, 2024.

Solar and Wind

Indiana Electric has entered into various PPAs to purchase solar power and wind power to meet its future generation needs as reported in the table below:

Power Type	Counterparty	Location	Expected Date in Service	Capacity (MW)	Term (in Years)
Solar	Clenera, LLC	Warrick County, Indiana	2026	100	25
Solar	Oriden	Vermillion County, Indiana	2026	185	15
Solar	Origis	Knox County, Indiana	2026	150	20
Wind	NextEra Energy, Inc.	Knox County, Illinois	2026	147	25
				582	

For further information about Indiana Electric's solar power and wind power activities, see "Item 2. Properties" and "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Regulatory Matters" in Item 7 of Part II of this report, which discussion is incorporated herein by reference.

Coal Purchases

Coal for coal-fired generating stations has been supplied from operators of nearby coal mines as there are substantial coal reserves in the southern Indiana area. Major suppliers are those that account for greater than 10% of Indiana Electric's coal purchases. For the year ended December 31, 2024, Sunrise LLC accounted for 88% of Indiana Electric's coal purchases, with the remaining 12% being purchased from other suppliers.

The table below presents information related to coal purchases during the year ended December 31, 2024 and coal inventory as of December 31, 2024:

	(In tons, except average cost per ton)
Coal purchased for generating electricity	883,308
Coal inventory as of December 31, 2024	263,321
Average cost of coal per ton	$54.41

Firm Purchase Supply

Indiana Electric enters into long-term purchase supply agreements to meet its generation needs as disclosed below:

Fuel Type	Provider	Location	Contract Expiration	Capacity (MW)	Purchased in 2024 (in GWh)
Coal	OVEC (1)	Indiana and Ohio	2040	32	178
Wind	Benton County Wind Farm, LLC	Benton County, Indiana	2028	30	83
Wind	Fowler Ridge II Wind Farm, LLC	Benton/Tippecanoe Counties, Indiana	2029	50	134
				112	395

(1) As part of its power portfolio, Indiana Electric is a 1.5% shareholder in the OVEC. Based on its participation in the ICPA between OVEC and its shareholder companies, Indiana Electric has the right to 1.5% of OVEC's generating capacity output and shares in 1.5% of the operating expenses and debt obligations of OVEC.

MISO-Related Activity

Indiana Electric is a member of the MISO, a FERC-approved regional transmission organization. The MISO serves the electric transmission needs of much of the Midcontinent region and maintains operational control over Indiana Electric's electric transmission facilities and generation facilities as well as other utilities in the region. Indiana Electric is an active participant in the MISO energy markets, bidding its owned generation into the Day Ahead and Real Time markets and procuring power for its retail customers at Locational Marginal Pricing as determined by the MISO market. MISO-related purchase and sale transactions are recorded using settlement information provided by the MISO. These purchase and sale transactions are accounted for on at least a net hourly position.

MISO-related activity for the year ended December 31, 2024 was as follows:

	In GWh
Net purchases (1)	2,406
Net sales (2)	—

(1) Represents intervals when purchases from the MISO were in excess of generation sold to the MISO.
(2) Represents intervals when sales to the MISO were in excess of purchases from the MISO. Net sales were insignificant during 2024 primarily due to the retirement of SIGECO's A.B. Brown coal generating facilities in 2023 and SIGECO's exit from joint operations in the Warrick 4 coal generating facility on January 1, 2024.

Interconnections

As of December 31, 2024, Indiana Electric had interconnections with Louisville Gas and Electric Company, Duke Energy Shared Services, Inc., Indianapolis Power & Light Company, Hoosier Energy Rural Electric Cooperative, Inc. and Big Rivers Electric Corporation providing the ability to simultaneously interchange approximately 645 MW during peak load periods. Indiana Electric, as required as a member of the MISO, has turned over operational control of the interchange facilities

and its own transmission assets to the MISO. Indiana Electric, in conjunction with the MISO, must operate the bulk electric transmission system in accordance with NERC Reliability Standards. As a result, interchange capability varies based on regional transmission system configuration, generation dispatch, seasonal facility ratings and other factors. Indiana Electric is in compliance with reliability standards promulgated by NERC.

SIGECO Securitization Subsidiary

SIGECO has a special purpose subsidiary, SIGECO Securitization Subsidiary, which it consolidates. This consolidated special purpose subsidiary is a wholly-owned, bankruptcy-remote entity that was formed solely for the purpose of facilitating the securitization financing of qualified costs. The obligations of the SIGECO Securitization Bonds are repaid through charges imposed on customers in Indiana Electric's service territory. For further discussion of the SIGECO Securitization Bonds and the outstanding balance as of December 31, 2024, see Note 12 to the consolidated financial statements.

Competition

There are no other electric transmission and distribution utilities in Indiana Electric's service area. Indiana Electric is a vertically integrated utility that owns the generation, transmission, and distribution components of a utility.

For another provider of transmission and distribution services to provide such services in Indiana Electric's territory, it would be required to obtain IURC approval of such service territory. Indiana service territory certificates are exclusive. Distributed generation (i.e., power generation located at or near the point of consumption) could result in reduced demand for Indiana Electric's distribution services but has not been a significant factor to date.

Seasonality

Indiana Electric's revenues are primarily derived from rates that it collects from customers in its service territory based on the amount of electricity it delivers. Indiana Electric's revenues and results of operations are subject to seasonality, weather conditions and other changes in electricity usage, with revenues generally being higher during the warmer months when more electricity is used for cooling purposes, and during the cooler months when more electricity is used for heating purposes.

Natural Gas (CenterPoint Energy and CERC)

CenterPoint Energy's and CERC's Natural Gas engage in regulated intrastate natural gas sales to, and natural gas transportation and storage for, residential, commercial, industrial and transportation customers. CenterPoint Energy's and CERC's Natural Gas provide permanent pipeline connections through interconnects with various interstate and intrastate pipeline companies through CEIP. CenterPoint Energy's and CERC's Natural Gas also provided services in Minnesota consisting of residential appliance repair and maintenance services along with HVAC equipment sales and home repair protection plans to natural gas customers in Indiana, Mississippi, Ohio and Texas through a third party as of December 31, 2024.

For information regarding the properties of the Natural Gas reportable segment, read "Properties — Natural Gas (CenterPoint Energy and CERC)" in Item 2 of this report, which information is incorporated herein by reference.

On February 19, 2024, CenterPoint Energy, through its subsidiary CERC Corp., entered into the LAMS Asset Purchase Agreement to sell its Louisiana and Mississippi natural gas LDC businesses. The transaction was approved by final orders issued by the MPSC on December 3, 2024 and by the LPSC on December 17, 2024. The transaction is expected to close in the first quarter of 2025. For further information, see Note 4 to the consolidated financial statements.

Customers

The table below reflects the number of CenterPoint Energy's and CERC's Natural Gas customers by state as of December 31, 2024:

	Residential	Commercial/ Industrial/ Transportation	Total Customers
Indiana (Indiana Gas)	606,536	55,745	662,281
Louisiana	231,962	16,214	248,176
Minnesota	859,065	72,890	931,955
Mississippi	123,175	13,152	136,327
Ohio	310,541	24,589	335,130
Texas	1,827,305	111,369	1,938,674
Total CERC Natural Gas	3,958,584	293,959	4,252,543
Indiana (SIGECO)	105,344	10,647	115,991
Total CenterPoint Energy Natural Gas	4,063,928	304,606	4,368,534

The largest metropolitan areas served in each state were Houston, Texas; Minneapolis, Minnesota; Shreveport, Louisiana; Biloxi, Mississippi; Evansville, Indiana; and Dayton, Ohio.

The table below reflects the percentage of total throughput by customer type for the year ended December 31, 2024:

	CenterPoint Energy	CERC
Residential	31 %	32 %
Commercial/Industrial and Transportation	69 %	68 %
Total Throughput	100 %	100 %

Seasonality

The demand for natural gas sales to residential customers and natural gas sales and transportation for commercial and industrial customers is seasonal and affected by variations in weather conditions. In 2024, approximately 64% and 65% of CenterPoint Energy's and CERC's Natural Gas total throughput occurred in the first and fourth quarters, respectively. These patterns reflect the higher demand for natural gas for heating purposes during the colder months.

Supply and Transportation

In 2024, CenterPoint Energy's Natural Gas purchased virtually all of its natural gas supply pursuant to contracts with remaining terms varying from a few months to three years. Major suppliers are those that account for greater than 10% of CenterPoint Energy's or CERC's annual natural gas supply purchases.

Major suppliers of natural gas for the year ended December 31, 2024 were as follows:

	CenterPoint Energy	CERC
Tenaska Marketing Ventures, LLC	33 %	31 %
BP Energy Company	11 %	12 %
Macquarie Energy, LLC	11 %	11 %
Total of major suppliers	55 %	54 %

Numerous other suppliers provided the remainder of CenterPoint Energy's and CERC's natural gas supply requirements.

CenterPoint Energy's and CERC's Natural Gas transports their natural gas supplies through various intrastate and interstate pipelines under contracts with remaining terms, including extensions, varying from one to fifteen years. CenterPoint Energy's and CERC's Natural Gas anticipates that these gas supply and transportation contracts will be renewed or replaced prior to their expiration.

CenterPoint Energy's and CERC's Natural Gas actively engage in commodity price stabilization pursuant to annual gas supply plans presented to and/or filed with each of its state regulatory authorities. These price stabilization activities include use of storage gas and contractually establishing structured prices (e.g., fixed price, costless collars and caps) with CenterPoint Energy's and CERC's Natural Gas' physical gas suppliers. Their gas supply plans generally call for 50–75% of normal winter supplies to be stabilized in some fashion.

The regulations of the states in which CenterPoint Energy's and CERC's Natural Gas operate allow them to pass through changes in the cost of natural gas, including savings and costs of financial derivatives associated with the index-priced physical supply, to their customers under purchased gas adjustment provisions in their tariffs. Depending upon the jurisdiction, the purchased gas adjustment factors are updated periodically, ranging from monthly to semi-annually. The changes in the cost of gas billed to customers are subject to review by the applicable regulatory bodies.

CenterPoint Energy's and CERC's Natural Gas use various third-party storage services or owned natural gas storage facilities to meet peak-day requirements and to manage the daily changes in demand due to changes in weather. CenterPoint Energy's and CERC's Natural Gas may also supplement contracted supplies and storage from time to time with stored LNG and propane-air plant production.

On an ongoing basis, CenterPoint Energy's and CERC's Natural Gas enter into contracts to provide sufficient supplies and pipeline capacity to meet their customer requirements. However, it is possible for limited service disruptions to occur from time to time due to weather conditions, transportation constraints and other events. As a result of these factors, supplies of natural gas may become unavailable from time to time, or prices may increase rapidly in response to temporary supply constraints or other factors.

CenterPoint Energy's and CERC's Natural Gas businesses continue to utilize AMAs associated with their utility distribution service in Indiana, Louisiana, Minnesota, Mississippi and Texas. Generally, AMAs are contracts between CenterPoint Energy's and CERC's Natural Gas and an asset manager that are intended to transfer the working capital obligation and maximize the utilization of the assets. In these agreements, CenterPoint Energy's and CERC's Natural Gas agrees to release transportation and storage capacity to other parties to manage natural gas storage, supply and delivery arrangements for CenterPoint Energy's and CERC's Natural Gas and to use the released capacity for other purposes when it is not needed for CenterPoint Energy's and CERC's Natural Gas. CenterPoint Energy's and CERC's Natural Gas may receive compensation from the asset manager through payments made over the life of the AMAs. CenterPoint Energy's and CERC's Natural Gas has an obligation to purchase their winter storage requirements that have been released to the asset manager under these AMAs. The AMAs have varying terms, the longest of which expires in 2029. Pursuant to the provisions of the agreements, CenterPoint Energy's and CERC's Natural Gas either sells natural gas to the asset manager and agrees to repurchase an equivalent amount of natural gas throughout the year at the same cost, or simply purchases its full natural gas requirements at each delivery point from the asset manager. For amounts outstanding under these AMAs, see Note 12 to the consolidated financial statements.

Competition

CenterPoint Energy's and CERC's Natural Gas compete primarily with alternate energy sources such as electricity and other fuel sources. In some areas, intrastate pipelines, other gas distributors and marketers also compete directly for gas sales to end users. In addition, as a result of federal regulations affecting interstate pipelines, natural gas marketers operating on these pipelines may be able to bypass CenterPoint Energy's and CERC's Natural Gas' facilities and market, sell and/or transport natural gas directly to commercial and industrial customers.

Corporate and Other (CenterPoint Energy)

CenterPoint Energy's Corporate and Other consists of corporate support operations that support CenterPoint Energy's business operations and also includes office buildings and other real estate used for business operations. CenterPoint Energy's Corporate and Other also consisted of energy performance contracting and sustainable infrastructure services by Energy Systems Group through June 30, 2023, the date of the sale of Energy Systems Group. For additional information on the sale of Energy Systems Group, see Note 4 to the consolidated financial statements.

REGULATION

The Registrants are subject to regulation by various federal, state and local governmental agencies, including the regulations described below. The following discussion is based on regulation in the Registrants' businesses as of December 31, 2024.

Federal Energy Regulatory Commission

FERC has jurisdiction under the NGA and the NGPA, as amended, to regulate the transportation of natural gas in interstate commerce and natural gas sales for resale in interstate commerce that are not first sales. FERC regulates, among other things, the construction of pipeline and related facilities used in the transportation and storage of natural gas in interstate commerce, including the extension, expansion or abandonment of these facilities. FERC also regulates the transmission and wholesale sales of electricity in interstate commerce, mergers, acquisitions and corporate transactions by electricity companies, energy markets, reliability standards and the issuance of short-term debt by public utilities regulated by FERC. FERC has authority to prohibit market manipulation in connection with FERC-regulated transactions, to conduct audits and investigations, and to impose significant civil penalties (up to approximately $1.6 million per day per violation, subject to periodic adjustment to account for inflation) for statutory violations and violations of the FERC's rules or orders.

Indiana Electric is a "public utility" under the FPA and is subject to regulation by FERC. Houston Electric is not a "public utility" under the FPA and, therefore, is not generally regulated by FERC, although certain of its transactions are subject to limited FERC jurisdiction. FERC has certain responsibilities with respect to ensuring the reliability of electric transmission service, including transmission facilities owned by Houston Electric and other utilities within ERCOT. FERC has designated NERC as the ERO to promulgate standards, under FERC oversight, for all owners, operators and users of the bulk power system. The ERO and FERC have authority to (a) impose fines and other sanctions on applicable entities that fail to comply with approved standards and (b) audit compliance with approved standards. FERC has approved the delegation by NERC of authority for reliability in ERCOT to the Texas RE and in MISO to ReliabilityFirst Corporation. Neither Houston Electric nor Indiana Electric anticipate that the reliability standards proposed by NERC and approved by FERC will have a material adverse impact on their operations. To the extent that Houston Electric and Indiana Electric are required to make additional expenditures to comply with these standards, it is anticipated that Houston Electric and Indiana Electric will seek to recover those costs through the transmission charges that are imposed on all distribution service providers within ERCOT and the MISO, respectively, for electric transmission provided.

As a public utility holding company, under the Public Utility Holding Company Act of 2005, CenterPoint Energy and its consolidated subsidiaries are subject to reporting and accounting requirements and are required to maintain certain books and records and make them available for review by FERC and state regulatory authorities in certain circumstances.

For a discussion of the Registrants' ongoing regulatory proceedings, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Regulatory Matters" in Item 7 of Part II of this report, which discussion is incorporated herein by reference.

State and Local Regulation – Electric Transmission & Distribution (CenterPoint Energy and Houston Electric)

Houston Electric is a member of ERCOT, which serves as the independent system operator and regional reliability coordinator for member electric power systems in most of Texas. The ERCOT market represents approximately 90% of the demand for power in Texas and is one of the nation's largest power markets. The ERCOT market operates under the reliability standards developed by NERC, approved by FERC and monitored and enforced by the Texas RE. The PUCT has primary jurisdiction over the ERCOT market to ensure the adequacy and reliability of electricity supply across the state's main interconnected power transmission grid.

The ERCOT ISO is responsible for operating the bulk electric power supply system in the ERCOT market. Houston Electric's transmission business, along with those of other owners of transmission facilities in Texas, supports the operation of the ERCOT ISO. Houston Electric participates with the ERCOT ISO and other ERCOT utilities to plan, design, obtain regulatory approval for and construct new transmission lines necessary to increase bulk power transfer capability and to remove existing constraints on the ERCOT transmission grid.

Houston Electric conducts its operations pursuant to a CCN issued by the PUCT that covers its present service area and facilities. The PUCT and certain municipalities have the authority to set the rates and terms of service provided by Houston Electric under cost-of-service rate regulation. Houston Electric holds non-exclusive franchises from certain incorporated municipalities in its service territory. In exchange for payment of fees, these franchises give Houston Electric the right to use the streets and public rights-of-way of these municipalities to construct, operate and maintain its transmission and distribution system and to use that system to conduct its electric delivery business and for other purposes that the franchises permit. The terms of the franchises, with various expiration dates, typically range from 30 to 40 years.

In ERCOT, end users purchase their electricity directly from certificated REPs. Houston Electric's distribution rates charged to REPs for residential and small commercial customers are primarily based on amounts of energy delivered, whereas

distribution rates for a majority of large commercial and industrial customers are primarily based on peak demand. All REPs in Houston Electric's service area pay the same rates and other charges for transmission and distribution services. This regulated delivery charge may include the transmission and distribution rate (which includes municipal franchise fees), a DCRF mechanism for recovery of incremental distribution-invested capital above that which is already reflected in the base distribution rate, a TEEEF mechanism for recovery of costs associated with leasing and operating TEEEF, a TCRF mechanism for recovery of approved wholesale transmission cost changes billed by a transmission service provider, a nuclear decommissioning charge associated with decommissioning the South Texas nuclear generating facility, an EECRF charge, and charges associated with securitization of regulatory assets, stranded costs and restoration costs. Transmission rates charged to distribution companies are based on amounts of energy transmitted under "postage stamp" rates that do not vary with the distance the energy is being transmitted. All distribution companies in ERCOT pay Houston Electric the same rates and other charges for transmission services.

With the IURC's approval, Indiana Electric is a member of the MISO, a FERC-approved regional transmission organization. The MISO serves the electrical transmission needs of much of the Midcontinent region and maintains operational control over Indiana Electric's electric transmission and generation facilities as well as those of other utilities in the region. Indiana Electric is an active participant in the MISO energy markets, bidding its owned generation into the Day Ahead and Real Time markets and procuring power for its retail customers at Locational Marginal Pricing as determined by the MISO market. Indiana Electric also receives transmission revenue that results from other members' use of Indiana Electric's transmission system. Generally, these transmission revenues, along with costs charged by the MISO, are considered components of base rates and any variance from that included in base rates is recovered from or refunded to retail customers through tracking mechanisms.

For a discussion of certain of Houston Electric's and Indiana Electric's ongoing regulatory proceedings, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Regulatory Matters" in Item 7 of Part II of this report, which discussion is incorporated herein by reference.

State and Local Regulation – Electric Generation (CenterPoint Energy)

The energy and capacity secured from Indiana Electric's available generation resources are utilized primarily to serve the needs of retail electric customers residing within Indiana Electric's franchised service territory. Costs of operating Indiana Electric's generation facilities are recovered through IURC-approved base rates as well as periodic rate recovery mechanisms including the CECA, ECA, FAC, MCRA, and RCRA mechanism. Costs that are deemed unreasonable or imprudent by the IURC may not be recoverable through retail electric rates. Indiana Electric also receives revenues from the MISO to compensate it for benefits the generation facilities provide to the transmission system. Proceeds from the sales of energy from Indiana Electric's generation facilities that exceed the requirements of retail customers are shared by Indiana Electric and retail electric customers.

The generation facilities owned and operated by Indiana Electric are subject to various environmental regulations enforced by the EPA and the IDEM. Operations of Indiana Electric's generation facilities are subject to regulation by the EPA and the IDEM as it pertains to the discharge of constituents from the generation facilities. For further discussion, see "Our Business — Environmental Matters" below.

For a discussion of Indiana Electric's ongoing regulatory proceedings, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Regulatory Matters" in Item 7 of Part II of this report, which discussion is incorporated herein by reference.

State and Local Regulation – Natural Gas (CenterPoint Energy and CERC)

In almost all communities in which CenterPoint Energy's and CERC's Natural Gas provides natural gas distribution services, they operate under franchises, certificates or licenses obtained from state and local authorities. The original terms of the franchises, with various expiration dates, typically range from 20 to 30 years. CenterPoint Energy's and CERC's Natural Gas expects to be able to renew expiring franchises. In most cases, franchises to provide natural gas utility services are not exclusive.

Substantially all of CenterPoint Energy's and CERC's Natural Gas is subject to cost-of-service rate regulation by the relevant state public utility commissions and, in Texas, by those municipalities that have retained original jurisdiction. In certain of the jurisdictions in which they operate, CenterPoint Energy's and CERC's Natural Gas have annual rate adjustment mechanisms that provide for changes in rates dependent upon certain changes in invested capital, earned returns on equity or actual margins realized.

For a discussion of certain of CenterPoint Energy's and CERC's Natural Gas' ongoing regulatory proceedings, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Regulatory Matters" in Item 7 of Part II of this report, which discussion is incorporated herein by reference.

Department of Transportation (CenterPoint Energy and CERC)

CenterPoint Energy and CERC are subject to regulation by PHMSA under the NGPSA and the HLPSA. The NGPSA delegated to PHMSA through DOT the authority to regulate gas pipelines. The HLPSA delegated to PHMSA through DOT the authority to develop, prescribe and enforce federal safety standards for the transportation of hazardous liquids by pipeline. Every four years PHMSA is up for reauthorization by Congress and with that reauthorization comes changes to the legislative requirements that Congress sets forth for the oversight of natural gas and hazardous liquid pipelines. In 2020, the PIPES Act was enacted. The PIPES Act reauthorized PHMSA through 2023 and imposed a few new mandates on the agency. The law establishes a PHMSA technology pilot, authorizes a new idled pipe operating status and contains process protections for operators during PHMSA enforcement proceedings. Section 114 of the PIPES Act is a self-mandating rule for natural gas pipeline operations like CERC's that focuses on processes and procedures to eliminate or reduce emissions during normal operations. Further, Section 113 of the PIPES Act directed PHMSA to develop regulations to require natural gas pipeline operators to implement leak detection and repair programs, as well as requirements for mitigating emissions in operations. The PIPES Act of 2023 was approved by the House Transportation and Infrastructure Committee on December 6, 2023 to reauthorize PHMSA's safety programs for the next four years. Final versions of the Section 113 Leak Detection and Repair, and Safety of Natural Gas Distribution Pipelines, 2020 PIPES Act rules remain frozen until a Department of Transportation appointee can review and proceed further.

In January 2021, PHMSA published a final rule amending the federal Pipeline Safety Regulations to ease regulatory burdens on the construction, operation, and maintenance of gas transmission, distribution, and gathering systems.

CenterPoint Energy and CERC anticipate that compliance with PHMSA's regulations, performance of the remediation activities by CenterPoint Energy's and CERC's Natural Gas and intrastate pipelines, and verification of records on maximum allowable operating pressure will continue to require increases in both capital expenditures and operating costs. The level of expenditures will depend upon several factors, including age, location and operating pressures of the facilities. In particular, the cost of compliance with the DOT's integrity management rules will depend on integrity testing and the repairs found to be necessary by such testing. Changes to the amount of pipe subject to integrity management, whether by expansion of the definition of the type of areas subject to integrity management procedures or of the applicability of such procedures outside of those defined areas, may also affect the costs incurred. Implementation by PHMSA of the PIPES Act, in particular the final rule implementing Section 113, acts reauthorizing PHMSA or other future acts may result in other regulations or the reinterpretation of existing regulations that could impact compliance costs. In addition, CenterPoint Energy and CERC may be subject to the DOT's enforcement actions and penalties if they fail to comply with pipeline regulations.

ENVIRONMENTAL MATTERS

The following discussion is based on environmental matters in the Registrants' businesses as of December 31, 2024. The Registrants' operations are subject to stringent and complex laws and regulations pertaining to the environment. As an owner or operator of natural gas pipelines, distribution systems and storage, electric transmission and distribution systems, steam electric and renewable generation systems and the facilities that support these systems, the Registrants must comply with these laws and regulations at the federal, state and local levels. These laws and regulations can restrict or impact the Registrants' business activities in many ways, including, but not limited to:

- restricting the way the Registrants can handle or dispose of wastes, including wastewater discharges and air emissions;
- limiting or prohibiting construction activities in sensitive areas such as wetlands, coastal regions or areas inhabited by endangered species;
- requiring remedial action and monitoring to mitigate environmental conditions caused by the Registrants' operations or attributable to former operations;
- enjoining the operations of facilities with permits issued pursuant to such environmental laws and regulations; and
- impacting the demand for the Registrants' services by directly or indirectly affecting the use or price of fossil fuels, including, but not limited to, natural gas.

To comply with these requirements, the Registrants may need to spend substantial amounts and devote other resources from time to time to, among other activities:

- construct or acquire new facilities and equipment;
- acquire permits for facility operations or purchase emissions allowances;
- modify, upgrade or replace existing and proposed equipment; and
- decommission or remediate waste management areas, fuel storage facilities and other locations.

Failure to comply with these laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, revocation of permits, the imposition of remedial actions and monitoring and the issuance of orders enjoining future operations. Certain environmental statutes impose strict, joint and several liability for costs required to assess, clean up and restore sites where hazardous substances have been stored, disposed or released. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and/or property damage allegedly caused by the release of hazardous substances or other waste products into the environment.

Increasingly, environmental regulation has resulted in more restrictions and limitations on activities that may impact the environment. There can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation and monitoring, and actual future expenditures may be different from the amounts currently anticipated. The Registrants try to anticipate future regulatory requirements that might be imposed and plan accordingly to maintain compliance with changing environmental laws and regulations.

Based on current regulatory requirements and interpretations, the Registrants do not believe that compliance with federal, state or local environmental laws and regulations will have a material adverse effect on their business, financial position, results of operations or cash flows. In addition, the Registrants believe that their current environmental remediation activities will not materially interrupt or diminish their operational ability. The Registrants cannot provide assurances that future events, such as changes in existing laws, the promulgation of new laws, or the development or discovery of new facts or conditions will not cause them to incur significant costs. The following is a discussion of material current environmental and safety issues, laws and regulations that relate to the Registrants' operations. The Registrants believe that they are in substantial compliance with these environmental laws and regulations.

Greenhouse Gas and Climate Change-Related Regulation and Compliance *(CenterPoint Energy)*

There is increasing attention being paid in the United States and worldwide to the issue of climate change. As a result, from time to time, regulatory agencies have considered the modification of existing laws or regulations or the adoption of new laws or regulations addressing the emissions of GHG on the state, federal, or international level. The EPA released its initial GHG regulation for fossil fuel-fired electric generating units in 2015. Since then, various iterations of GHG regulations have been promulgated, withdrawn and litigated, and the current rule applicable to fossil fuel-fired electric generating units was finalized in April 2024. In April 2024, the EPA finalized the current New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, Reconstructed Fossil Fuel-Fired Units; and Repeal of the Affordable Clean Energy Rule, which applies new GHG performance standards for those existing coal-fired power plants expected to continue operation beyond December 31, 2029. The rule is currently being challenged by a variety of stakeholders in litigation before the Circuit Court of Appeals for the D.C. Circuit. In October 2024, the U.S. Supreme Court declined to stay the implementation of the rule while the rule is on judicial review. On February 19, 2021, the United States formally rejoined the Paris Agreement, which drove a renewed regulatory push to require further GHG emission reductions from the energy sector, and led negotiations at the global climate conference in Glasgow, Scotland. On April 22, 2021, the United States announced goals of 50% reduction of economy-wide GHG emissions, and 100% carbon-free electricity by 2035 from a 2021 baseline, which formed the basis of the U.S. commitments announced in Glasgow. Nevertheless, on January 20, 2025, President Trump signed an executive order to withdraw the United States from the Paris Agreement, marking a significant shift in U.S. climate policy. Pursuant to the terms of the Paris Agreement, the withdrawal will take effect on January 27, 2026. Additionally, in January 2025, President Trump signed a series of executive orders that, among other things, (i) call upon the EPA to submit a report on the continuing applicability of its endangerment finding for GHGs under the Clean Air Act and issue guidance on the "social cost of carbon" to consider whether such metric should be eliminated, (ii) direct federal executive departments and agencies to initiate a regulatory freeze for certain rules that have not taken effect, pending review by the newly appointed agency head, (iii) temporarily halt certain federal government agencies from issuing approvals, permits and loans for onshore wind projects pending the completion of certain assessments and reviews and (iv) pause the disbursement of funds appropriated through the IRA and the Infrastructure Investments and Jobs Act.

In September 2021, CenterPoint Energy announced its net zero emissions goals for both Scope 1 emissions and certain Scope 2 emissions by 2035 as well as a goal to reduce certain Scope 3 emissions by 20% to 30% by 2035 from a 2021 baseline. Because Texas is an unregulated market, CenterPoint Energy's Scope 2 emissions estimates do not take into account Texas electric transmission and distribution assets in the line loss calculation and, in addition, exclude emissions related to purchased power in Indiana between 2024 and 2026 as estimated. CenterPoint Energy's Scope 3 emissions estimates are based on the total

natural gas supply delivered to residential and commercial customers as reported in the U.S. Energy Information Administration (EIA) Form EIA-176 reports and do not take into account the emissions of transport customers and emissions related to upstream extraction. These emission goals are expected to be used to position CenterPoint Energy to comply with anticipated future regulatory requirements from any future administrations to further reduce GHG emissions. For more information regarding CenterPoint Energy's net zero and GHG emissions reduction goals and their related risks, see "Risk Factors — Risk Factors Affecting Regulatory, Environmental and Legal Risks — CenterPoint Energy is subject to operational and financial risks ..." CenterPoint Energy's and CERC's revenues, operating costs and capital requirements could be adversely affected as a result of any regulatory action that would require installation of new control technologies or a modification of their operations or would have the effect of reducing the consumption of natural gas. The IRA established the Methane Emissions Reduction Program, which imposes a charge on methane emissions from certain natural gas transmission facilities, the rules for which were finalized on November 18, 2024, and the EPA published final, new regulations targeting reductions in methane emissions on March 8, 2024, which may increase costs related to production, transmission and storage of natural gas.

CenterPoint Energy's net zero emissions goals are aligned with Indiana Electric's generation transition plan and are expected to position Indiana Electric to comply with anticipated future regulatory requirements related to GHG emissions reductions. Houston Electric, in contrast to some electric utilities including Indiana Electric, does not generate electricity, other than through TEEEF, and thus is not directly exposed to the risk of high capital costs and regulatory uncertainties that face electric utilities that burn fossil fuels to generate electricity. Nevertheless, Houston Electric's and Indiana Electric's revenues could be adversely affected to the extent any resulting regulatory action has the effect of reducing consumption of electricity by ultimate consumers within their respective service territories. Likewise, incentives to conserve energy or to use energy sources other than natural gas could result in a decrease in demand for the Registrants' services. For example, Minnesota has enacted the Natural Gas Innovation Act that seeks to provide customers with access to renewable energy resources and innovative technologies, with the goal of reducing GHG emissions. Further, certain local government bodies have introduced or are considering requirements and/or incentives to reduce energy consumption by certain specified dates. For example, Minneapolis has adopted carbon emission reduction goals in an effort to decrease reliance on natural gas. Additionally, cities in Minnesota within CenterPoint Energy's Natural Gas operational footprint are considering initiatives to eliminate natural gas use in buildings and focus on electrification. Also, Minnesota cities may consider seeking legislative authority for the ability to enact voluntary enhanced energy standards for all development projects. These initiatives could have a significant impact on CenterPoint Energy and its operations, and this impact could increase if other cities and jurisdictions in its service area enact similar initiatives. Further, our third-party suppliers, vendors and partners may also be impacted by climate change laws and regulations, which could impact CenterPoint Energy's business by, among other things, causing permitting and construction delays, project cancellations or increased project costs passed on to CenterPoint Energy. Conversely, regulatory actions that effectively promote the consumption of natural gas because of its lower emissions characteristics relative to other fossil fuels would be expected to benefit CenterPoint Energy and CERC and their natural gas-related businesses. At this time, however, we cannot quantify the magnitude of the impacts from possible new regulatory actions related to GHG emissions, either positive or negative, on the Registrants' businesses.

On March 6, 2024, the SEC adopted final rules that require the Registrants to disclose certain climate-related information in registration statements and annual reports. Litigation challenging the new rule was filed by multiple parties in multiple jurisdictions, which have been consolidated and assigned to the U.S. Court of Appeals for the Eighth Circuit. On April 4, 2024, the SEC announced that it is voluntarily delaying the implementation of the climate disclosure regulations while the U.S. Court of Appeals considers the litigation. While a majority of the reporting requirements would have been applicable to the Registrants in the fiscal year beginning in 2025, with the addition of assurance reporting for GHG inventories starting in 2029 for large accelerated filers, as of April 12, 2024, the effective date of the final rules has been delayed indefinitely and the SEC has indicated that it will publish a document in the Federal Register at the conclusion of the stay addressing a new effective date for the final rules. On February 11, 2025, the SEC notified the U.S. Court of Appeals of a statement issued by the SEC's Acting Chairman regarding, among other things, the fact that the majority of current SEC Commissioners had previously voted against adopting the rules, and requested that the U.S. Court of Appeals not schedule the case for argument to provide time for the SEC to deliberate and determine the appropriate next steps in the cases. The Registrants continue to evaluate the impact of the final rules on their respective consolidated financial statements and related disclosures.

Compliance costs and other effects associated with climate change, reductions in GHG emissions and obtaining renewable energy sources remain uncertain. Although the amount of compliance costs remains uncertain, any new regulation or legislation relating to climate change will likely result in an increase in compliance costs. While the requirements of a federal or state rule remain uncertain, CenterPoint Energy will continue to monitor regulatory activity regarding GHG emission standards that may affect its business. Currently, CenterPoint Energy does not purchase carbon credits. In connection with its net zero and GHG emissions goals, CenterPoint Energy expects to purchase carbon credits in the future; however, CenterPoint Energy does not currently expect the number of credits, or cost for those credits, to be material.

For further information on climate change trends and uncertainties, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Regulatory Matters — Climate Change Trends and Uncertainties" in Item 7 of Part II of this report.

Air Emissions

The Registrants' operations are subject to the federal Clean Air Act and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including electric generating facilities and natural gas processing plants and compressor stations, and also impose various monitoring and reporting requirements. Such laws and regulations may require pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions or result in the increase of existing air emissions. The Registrants may be required to obtain and strictly comply with air permits containing various emissions and operational limitations, or utilize specific emission control technologies to limit emissions. Failure to comply with these requirements could result in monetary penalties, injunctions, conditions or restrictions on operations, and potentially criminal enforcement actions. The Registrants may be required to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions.

Water Discharges

The Registrants' operations are subject to the Federal Water Pollution Control Act of 1972, as amended, also known as the Clean Water Act, and analogous state laws and regulations. These laws and regulations impose detailed requirements and strict controls regarding the discharge of pollutants into waters of the United States. The unpermitted discharge of pollutants, including discharges resulting from a spill or leak incident, is prohibited. The Clean Water Act and regulations implemented thereunder also prohibit discharges of dredged and fill material into wetlands and other waters of the United States unless authorized by an appropriately issued permit. Any unpermitted release of petroleum or other pollutants from the Registrants' pipelines or facilities could result in fines or penalties as well as significant remedial obligations.

Waters of the United States

In April 2020 the EPA proposed a new set of rules that sought to clarify the Clean Water Act's jurisdiction over "waters of the United States," but that set of rules was later vacated by decisions in the U.S. federal district courts in New Mexico and Arizona. On December 30, 2022, the EPA and the U.S. Army Corps of Engineers announced the final "Revised Definition of 'waters of the United States"' rule, which was published on January 18, 2023 and became effective on March 20, 2023. However, on May 25, 2023, the U.S. Supreme Court issued a decision limiting the scope of federal jurisdiction over wetlands in the case of *Sackett v. Environmental Protection Agency*, and on August 29, 2023, the EPA issued a final rule that seeks to conform with the U.S. Supreme Court decision. As a result of ongoing rulemaking litigation, the Registrants' operations in all states with the exception of Minnesota fall under the pre-2015 regulatory regime consistent with the Supreme Court decision in *Sackett*, while operations in Minnesota fall under the 2023 rule, as amended. CenterPoint Energy is unable to predict the outcome of current or future litigation or regulatory proceedings, but does not expect a material impact on its operations relating to these rules. CenterPoint Energy will continue to monitor regulatory and legal developments relating to the Clean Water Act that may affect its business.

ELG

In 2015, the EPA finalized revisions to the existing steam electric wastewater discharge standards, which set more stringent wastewater discharge limits and effectively prohibited further wet disposal of coal ash in ash ponds. In February 2019, the IURC approved Indiana Electric's ELG Compliance Plan for its F.B. Culley Generating Station, which was completed in compliance with the requirements of ELG. On April 25, 2024, the EPA released its final Supplemental ELG and Standards for the Steam Electric Generating Point Source Category. The Registrants currently anticipate that they will be in compliance with the Supplemental ELG Guidelines at the Culley facility due to previous wastewater treatment upgrades.

Cooling Water Intake Structures

Section 316 of the federal Clean Water Act requires steam electric generating facilities use "best technology available" to minimize adverse environmental impacts on a body of water. In May 2014, the EPA finalized a regulation requiring installation of "best technology available" to mitigate impingement and entrainment of aquatic species in cooling water intake structures. Indiana Electric is currently completing the required ecological studies and anticipates timely compliance at its F.B. Culley facility in 2025.

Hazardous Waste

The Registrants' operations generate wastes, including some hazardous wastes, that are subject to the federal RCRA, and comparable state laws, which impose detailed requirements for the handling, storage, treatment, transport and disposal of hazardous and solid waste. RCRA currently exempts many natural gas gathering and field processing wastes from classification as hazardous waste. Specifically, RCRA excludes from the definition of hazardous wastewaters produced and other wastes associated with the exploration, development or production of crude oil and natural gas. However, these oil and gas exploration and production wastes are still regulated under state law and the less stringent non-hazardous waste requirements of RCRA. Moreover, ordinary industrial wastes such as paint wastes, waste solvents, laboratory wastes and waste compressor oils may be regulated as hazardous waste. The transportation of natural gas in pipelines may also generate some hazardous wastes that would be subject to RCRA or comparable state law requirements.

Coal Ash

Indiana Electric has three ash ponds, two at the F.B. Culley facility (Culley East and Culley West) and one at the A.B. Brown facility. In 2015, the EPA finalized its CCR Rule, which regulates coal ash as non-hazardous material under the RCRA. The final rule allows beneficial reuse of ash, and the majority of the ash generated by Indiana Electric's remaining generating units will continue to be beneficially reused. Indiana Electric is required to perform integrity assessments, including ground water monitoring, at its F.B. Culley and A.B. Brown generating stations. The ground water studies were necessary to determine the remaining service life of the ponds and whether a pond must be retrofitted with liners or closed in place. Groundwater monitoring indicates potential groundwater impacts adjacent to Indiana Electric's ash impoundments, and further analysis is ongoing. The CCR Rule required companies to complete location restriction determinations by October 18, 2018. Indiana Electric completed its evaluation and determined that one F.B. Culley pond (Culley East) and the A.B. Brown pond failed the aquifer placement location restriction. As a result of this failure, Indiana Electric was required to cease disposal of new ash in the ponds and commence closure of the ponds by April 11, 2021. Indiana Electric filed timely requests for extensions available under the CCR Rule that would allow Indiana Electric to continue to use the ponds through October 15, 2023. On January 22, 2021, Indiana Electric received letters from the EPA for both the F.B. Culley and A.B. Brown facilities that determined Indiana Electric's extension submittals complete and extended the compliance deadline of April 11, 2021 until the EPA issues a final decision on the extension requests. On October 5, 2022, SIGECO received a proposed conditional approval of its extension request for the A.B. Brown facility. Both the Culley East and A.B. Brown facility have been taken out of service in a timely manner per the commitments made to the EPA in the extension requests filed for both ponds. The Culley West pond was closed under CCR provisions applicable to inactive ponds, and closure activities were completed in December 2020. For further discussion about Indiana Electric's ash ponds, see Note 14(d) to the consolidated financial statements.

On April 25, 2024, the EPA released its final Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals from Electric Utilities; Legacy CCR Surface Impoundments rule (CCR Legacy Rule), which was published in the federal register in May 2024. The CCR Legacy Rule requires companies to investigate previously closed impoundments that were used historically for ash disposal or locations which have had ash placed on them in amounts set forth in the CCR Legacy Rule. The Registrants have completed their preliminary review of potential sites that will require further investigation under the CCR Legacy Rule and identified certain sites in Indiana for further evaluation. For further discussion about Indiana Electric's sites identified pursuant to the CCR Legacy Rule, see Note 14(d) to the consolidated financial statements.

Liability for Remediation

CERCLA, also known as "Superfund," and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons responsible for the release of "hazardous substances" into the environment. Classes of PRPs include the current and past owners or operators of sites where a hazardous substance was released and companies that disposed or arranged for the disposal of hazardous substances at offsite locations such as landfills. Although petroleum, as well as natural gas, is expressly excluded from CERCLA's definition of a "hazardous substance," in the course of the Registrants' ordinary operations they do, from time to time, generate wastes that may fall within the definition of a "hazardous substance." CERCLA authorizes the EPA and, in some cases, third parties, to take action in response to threats to the public health or the environment and to recover the costs they incur from the responsible classes of persons. Under CERCLA, the Registrants could potentially be subject to joint and several liability for the costs of cleaning up and restoring sites where hazardous substances have been released, for damages to natural resources, and for associated response and assessment costs, including for the costs of certain health studies.

Liability for Preexisting Conditions

For information about preexisting environmental matters, see Note 14(d) to the consolidated financial statements.

HUMAN CAPITAL

CenterPoint Energy believes its employees are critical to safely delivering electricity and natural gas across its service territories and seeks to create an open and safe work environment. CenterPoint Energy's core values—safety, integrity, accountability, initiative and respect—guide how it makes decisions and provide the foundation for a strong culture of ethics where employees are responsible for upholding these values and following CenterPoint Energy's Ethics and Compliance Code.

The following table sets forth the number of employees by Registrant and reportable segment as of December 31, 2024:

	Number of Employees			Number of Employees Represented by Collective Bargaining Groups		
Reportable Segment	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC
Electric	3,184	2,839	—	1,699	1,511	—
Natural Gas	3,656	—	3,390	1,651	—	1,587
Corporate and Other (1)	2,032	—	—	135	—	—
Total	8,872	2,839	3,390	3,485	1,511	1,587

(1) Employees in the Corporate and Other segment provide services to the Electric and Natural Gas segments and the costs of these services have been charged directly to the Electric and Natural Gas segments using assignment methods that management believes are reasonable. For further information, see Note 18 to the consolidated financial statements.

CenterPoint Energy's workforce includes 3,485 employees represented by collective bargaining agreements. For information about the status of collective bargaining agreements, see Note 8(j) to the consolidated financial statements.

Talent Attraction, Development and Retention. CenterPoint Energy's human capital priorities include attracting, retaining and developing high performing talent through its talent management activities. CenterPoint Energy endeavors to attract quality candidates through its recruitment and selection processes. CenterPoint Energy recruits qualified employees regardless of race, gender, color, sexual orientation, age, religion, national origin, or physical or mental disability. The talent acquisition team actively promotes CenterPoint Energy on college campuses to create awareness of our offerings to engineering, finance and technical occupations, and maintains relationships with student organizations at many institutions throughout our footprint.

CenterPoint Energy takes a strategic approach to attracting, retaining, and developing its workforce. CenterPoint Energy's strategy combines succession planning along with internal talent development as essential elements of overall workforce development. To support its commitment to delivering electricity and natural gas safely and reliably, CenterPoint Energy focuses on the continuous development of its greatest assets, its employees, to build a sustainable leadership pipeline. To meet the business's future needs, CenterPoint Energy's goal is to create great leaders capable of developing their employees, while supporting the business goals and maintaining a high-performing workforce. CenterPoint Energy has a number of tools for leadership and employee development that expand opportunities available to employees. CenterPoint Energy conducts regular talent discussions, including succession planning with all levels of leadership to provide business continuity and identify its future leaders and opportunities. CenterPoint Energy invests in employee development throughout the year to align performance to business needs, drive development planning and contribute to career progression. CenterPoint Energy's processes and progress are reviewed regularly for continuous improvement.

Engagement. CenterPoint Energy is dedicated to advancing an ethical and high performance work environment where business results are achieved through the experience, skills, abilities and talents of the whole workforce. CenterPoint Energy aims to create a workplace where every employee is engaged, aligned with our values, strategy, goals and priorities, and understands how each person contributes to the Company's long-term performance. In 2024, CenterPoint Energy's senior leadership team held quarterly town hall meetings with employees to share key Company updates, with employees across the Company participating in person or via video conference.

Compensation and Benefits. CenterPoint Energy is committed to providing its employees with competitive pay and benefits. Its compensation philosophy is to maintain employee total compensation that is competitive with the relevant markets, internally equitable, and based on company and individual performance. CenterPoint Energy expects that this will enable it to attract, motivate and retain employees with the skills and competencies necessary to achieve its business strategy. In addition to

competitive compensation, CenterPoint Energy provides its employees with a comprehensive benefits package designed to help employees stay healthy, care for their families, plan for the future and enjoy peace of mind. The benefits package includes medical, dental, vision, life, disability and accidental insurance coverage; retirement, company match savings plans; paid time off, parental leave, wellness and employee assistance programs. The employee wellness resources encompass support for mental, financial and physical health.

INFORMATION ABOUT OUR EXECUTIVE OFFICERS
(as of February 10, 2025)

Name	Age	Title
Jason P. Wells	47	President and Chief Executive Officer
Christopher A. Foster	46	Executive Vice President and Chief Financial Officer
Monica Karuturi	46	Executive Vice President and General Counsel
Jason M. Ryan	49	Executive Vice President, Regulatory Services and Government Affairs
Darin M. Carroll	48	Senior Vice President, Electric Business
Richard C. Leger	47	Senior Vice President, Natural Gas Business

Jason P. Wells has served as President and Chief Executive Officer of CenterPoint Energy and a member of the Board of Directors of CenterPoint Energy since January 5, 2024. Previously he served as President and Chief Operating Officer of CenterPoint Energy from May 2023 to January 2024; as President, Chief Operating Officer and Chief Financial Officer of CenterPoint Energy from January 2023 to May 2023; and as Executive Vice President and Chief Financial Officer of CenterPoint Energy from September 2020 to December 2022. Prior to joining CenterPoint Energy, Mr. Wells served as Executive Vice President and Chief Financial Officer of PG&E Corporation, a publicly traded electric utility holding company serving customers in Northern and Central California through its subsidiary Pacific Gas and Electric Company, from June 2019 to September 2020. He previously served as Senior Vice President and Chief Financial Officer of PG&E Corporation from January 2016 to June 2019 and as Vice President, Business Finance of Pacific Gas and Electric Company from August 2013 to January 2016. PG&E Corporation filed Chapter 11 bankruptcy on January 29, 2019 and successfully emerged from bankruptcy on July 1, 2020. He also served in various finance and accounting roles of increasing responsibility at Pacific Gas and Electric Company. Mr. Wells earned his bachelor's degree and master's degree in accounting, both from the University of Florida. He is a certified public accountant. Mr. Wells serves on the Executive Committee and Board for the Greater Houston Partnership, the Advisory Board of the Kinder Institute for Urban Research at Rice University, and the Boards of Central Houston, Inc. and M.D. Anderson Cancer Center.

Christopher A. Foster has served as Executive Vice President and Chief Financial Officer of CenterPoint Energy since May 2023. Previously, he served as Executive Vice President and Chief Financial Officer of PG&E Corporation, a publicly traded electric utility holding company serving customers in Northern and Central California through its subsidiary Pacific Gas and Electric Company, from March 2021 to May 2023. He previously served in various positions of increasing responsibilities at PG&E since 2011, including as Vice President and Interim Chief Financial Officer from September 2020 to March 2021, and Vice President, Treasury and Investor Relations from March 2020 to September 2020. PG&E Corporation filed Chapter 11 bankruptcy on January 29, 2019 and successfully emerged from bankruptcy on July 1, 2020. He earned his bachelor's degree from Michigan State University. Mr. Foster serves on the Board of Exploratorium, a San Francisco-based science and technology museum, as well as the Board of Directors of the Houston Parks Board.

Monica Karuturi has served as Executive Vice President and General Counsel of CenterPoint Energy since January 2022. She previously served as Senior Vice President and General Counsel from July 2020 to January 2022; as Vice President and Deputy General Counsel from April 2019 to July 2020; as Vice President and Associate General Counsel - Corporate and Securities from October 2015 to April 2019; and as Associate General Counsel - Corporate from September 2014 to October 2015. Prior to joining CenterPoint Energy, Ms. Karuturi served as counsel for LyondellBasell Industries for corporate and finance matters and strategic transactions. Ms. Karuturi earned her bachelor's degree from Brown University, master's degree in health policy and management from Columbia University, and juris doctorate from Georgetown University Law Center. Ms. Karuturi was appointed as a Commissioner of the Texas Access to Justice Commission by the Texas Supreme Court in June 2015 and served in this capacity until June 2021. She was also appointed as Chair of the Houston Bar Foundation in 2021 and served until December 2024. She currently serves as a member of the Board of Directors of the Houston Zoo.

Jason M. Ryan has served as Executive Vice President, Regulatory Services and Government Affairs of CenterPoint Energy since January 2022. He previously served as Senior Vice President, Regulatory Services and Government Affairs from July 2020 to January 2022; as Senior Vice President and General Counsel from April 2019 to July 2020; as Senior Vice

President, Regulatory and Government Affairs from February 2019 to April 2019; as Vice President of Regulatory and Government Affairs and Associate General Counsel from March 2017 to February 2019; and as Vice President and Associate General Counsel from September 2014 to March 2017. He was appointed to the Texas Diabetes Council by Texas Governor Perry in 2013 for a term ending in 2019; he was reappointed by Texas Governor Abbott in 2019 for a term ending in 2025. Mr. Ryan earned his bachelor's degree from the Texas McCombs School of Business and juris doctorate from the University of Texas School of Law. Mr. Ryan currently serves on the boards of the Lone Star Flight Museum and the Association of Electric Companies of Texas and on the advisory board of the Strategic AI Program at Houston Christian University. He also serves on the executive committee of the legal committee of the American Gas Association.

Darin M. Carroll has served as Senior Vice President, Electric Business of CenterPoint Energy since July 2024. He previously served as Senior Vice President, Natural Gas Business from January 2023 to July 2024; as Senior Vice President, Operations Support from January 2022 to January 2023; and as Vice President, Operations Support from February 2019 to January 2022. Prior to Vectren's acquisition by CenterPoint Energy, Mr. Carroll served as Director, Operations from February 2014 to February 2019 of Vectren. He earned his bachelor's degree from the University of Southern Indiana. Mr. Carroll currently serves on the Executive Committee and Board of Directors of the Junior Achievement of Southeast Texas and as a member of the Research Advisory Committee of the Electric Power Research Institute. He has also previously been on the Board of Directors of the American Gas Association, the Southern Gas Association, and the Guardianship Services of Southwestern Indiana, as well as a trustee of the American Gas Foundation. Mr. Carroll has also served as a member of the Indiana Energy Association Gas Operations Committee, Midwest Energy Association Electric Operations Steering Committee, and American Gas Association Field Operations Committee. He earned a bachelor's degree from the University of Southern Indiana in Evansville, Indiana.

Richard C. Leger has served as Senior Vice President, Natural Gas Business of CenterPoint Energy since January 2025. Mr. Leger previously served in various positions of increasing responsibilities at CenterPoint Energy since 2001, including as Interim Senior Vice President, Natural Gas Business from July 2024 to December 2024; as Senior Vice President, Indiana Electric from January 2022 to July 2024; as Vice President of Gas Operations, Indiana and Ohio from February 2019 to January 2022; as Director, District Operations for Little Rock, Arkansas from November 2015 to February 2019; as Director, Regulatory Affairs from August 2011 to November 2015; and as Manager, Sales and Conservation Improvement Program from August 2010 to August 2011. Mr. Leger currently serves as a board member for the American Gas Association, Southern Gas Association, United Way of Southwestern Indiana and Golf Gives Back. He is also a trustee of the American Gas Foundation and a former chair of the Southeast Energy Efficiency Alliance. In addition, Mr. Leger served six years in the Louisiana Army National Guard. He earned two bachelor's degrees in accounting and marketing from McNeese State University.

Item 1A. *Risk Factors*

CenterPoint Energy is a holding company that conducts all of its business operations through subsidiaries, primarily Houston Electric, CERC and SIGECO. The following, along with any additional legal proceedings identified or incorporated by reference in Item 3 of this combined report on Form 10-K, summarizes the principal risk factors associated with the holding company and the businesses conducted by its subsidiaries. However, additional risks and uncertainties either not presently known or not currently believed by management to be material may also adversely affect CenterPoint Energy's businesses. For other factors that may cause actual results to differ from those indicated in any forward-looking statement or projection contained in this combined report on Form 10-K, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Certain Factors Affecting Future Earnings" in Item 7, which should be read in conjunction with the risk factors contained in this Item 1A. Carefully consider each of the risks described below, including those relating to Houston Electric, LLC and CenterPoint Energy Resources Corp., which, along with CenterPoint Energy, Inc., are collectively referred to as the Registrants. Unless the context indicates otherwise, where appropriate, information relating to a specific registrant has been segregated and labeled as such and specific references to Houston Electric and CERC in this section also pertain to CenterPoint Energy. In this combined report on Form 10-K, the terms "our," "we" and "us" are used as abbreviated references to CenterPoint Energy, Inc. together with its consolidated subsidiaries.

Risk Factors Affecting Operations

Electric Generation, Transmission and Distribution (CenterPoint Energy and Houston Electric)

Disruptions at power generation facilities, generation inadequacy or directives issued by regulatory authorities could cause interruptions in Houston Electric's and Indiana Electric's ability to provide transmission and distribution services and adversely affect their reputation, financial condition, results of operations and cash flows.

Houston Electric owns the transmission and distribution infrastructure in its service territory that delivers electric power to its customers, but it does not own or operate any power generation facilities, except for its operation of TEEEF. Indiana Electric owns and operates power generation facilities in addition to the transmission and distribution infrastructure in its service territory. Both Houston Electric and Indiana Electric must follow the directives issued by their respective independent system operator, ERCOT and MISO, respectively. ERCOT and MISO have and may in the future issue directives requiring members to implement controlled outages as a result of an emergency or reliability issues, and Houston Electric has faced and may in the future face challenges to its planning and preparation for such directives and its implementation of Load Shed, including, for example, allegations that it had discretion as to how to shed load and which customers experienced outages and the duration of those outages. As a result, claims and lawsuits could be filed against Houston Electric and Indiana Electric for personal injury, property damage or other damage or loss as a result of their respective Load Shed planning, preparation, implementation, and decisions in order to meet the directives of ERCOT and MISO, respectively. For example, in February 2021, the ERCOT regulated Texas electric system experienced extreme winter weather conditions and an unprecedented power generation shortage. The amount of electricity generated by the state's power generation companies was insufficient to meet the amount demanded by customers. This resulted in ERCOT directing TDUs to significantly Load Shed, which caused customer outages across the ERCOT electric grid of Texas, including in Houston Electric's service territory. See Note 7 to the consolidated financial statements and "— Houston Electric's use of TEEEF ..." for further information. If power generation capacity is severely disrupted or is inadequate for any reason in the future, Houston Electric's or Indiana Electric's transmission and distribution services may be diminished or interrupted. Further, as with the lawsuits filed in the aftermath of the February 2021 Winter Storm Event, claims and lawsuits could be filed against the Registrants, and our reputation, financial condition, results of operations and cash flows could be adversely affected.

Additionally, Indiana Electric's generating facilities and the generating facilities that supply the power transmitted by Houston Electric and Indiana Electric are subject to operational risks that have and may in the future result in unscheduled plant outages, unanticipated operation and maintenance expenses and increased purchase power costs. For example, in June 2022, Culley 3, a coal-fired generation unit, experienced a boiler feed pump turbine failure that caused the unit to be out of service for nearly nine months. In this time frame, CenterPoint Energy purchased energy on the open market. Such open market purchases have and may again result in increased costs and have an adverse impact on our operations, financial condition, results of operations and cash flows. Further, Indiana Electric is party to a number of PPAs with third parties. Indiana Electric's power generation may be disrupted or otherwise insufficient if third parties do not deliver required power under our PPAs. These operational risks can arise from circumstances such as facility shutdowns or malfunctions due to equipment failure or operator error; aging infrastructure; interruption of fuel supply or increased prices of fuel as a result of, among other things, contract expirations, inflation and/or tariffs; disruptions in the delivery of electricity; inability to comply with regulatory or permit requirements; labor disputes; or natural disasters, all of which could adversely affect Indiana Electric's and Houston Electric's businesses. Further, Indiana Electric currently relies on coal for a portion of its generation capacity. Indiana Electric purchases the majority of its coal supply from a single, unrelated party and, although the coal supply is under long-term contract, the loss of this supplier or transportation interruptions could adversely affect its ability to deliver electricity to its customers and adversely impact Indiana Electric's financial condition, results of operations and cash flows. In 2021 and part of 2022, Indiana Electric experienced coal supply shortages due to labor shortages that the coal industry experienced. While the coal supply shortage that Indiana Electric experienced did not impact its ability to deliver electricity to its customers, labor shortages as well as supply shortages in the future, whether caused by insufficient supply or supplier bankruptcy or other regulatory and supply issues in the mining industry, may lead to increased cost and have an adverse impact on our operations, financial condition, results of operations and cash flows. See "— Disruptions to the global supply..." As Indiana Electric continues its generation transition and more renewable energy sources come online, Indiana Electric's generating facilities may experience unanticipated disruptions as a result of renewable supply shortages, including, but not limited to, adverse weather such as cloudy or windless days. Additionally, such disruptions could adversely affect its ability to deliver electricity to its customers and adversely impact Indiana Electric's financial condition, results of operations and cash flows.

The operations of Houston Electric and Indiana Electric are subject to the usual hazards associated with high-voltage electricity transmission and distribution, including inclement or severe weather, natural disasters, including wildfires, mechanical failure, contact with electrified facilities by people, equipment, and debris, unscheduled downtime, equipment

interruptions, contamination, remediation, explosions, fires, chemical spills, discharges or releases of toxic or hazardous substances, and other environmental risks. Such hazards can cause personal injury and loss of life, severe damage to or destruction of property and equipment, including loss of transmission and distribution lines and related equipment and damage to solar panels, and environmental damage, and may result in suspension of operations, disruption of service to customers, and the imposition of civil or criminal penalties. For example, Hurricane Beryl caused significant damage to Houston Electric's electric delivery system, resulting in a substantial number of its customers (peaking at more than 2.1 million customers out of 2.8 million customers) being without power, many for extended periods of time. Houston Electric and Indiana Electric maintain property and casualty insurance but are not fully insured against all potential hazards incident to their businesses.

Indiana Electric's execution of its generation transition plan, including its IRP, is subject to various risks, including timely recovery of capital investments and increased costs and risks related to the timing and cost of development and/or construction of new generation facilities.

Indiana requires each electric utility to perform and submit an IRP to the IURC every three years, unless extended, that uses economic modeling to consider the costs and risks associated with available resource options to provide reliable electric service for the next 20-year period. Indiana Electric has used past IRPs and will continue to use future IRPs to evaluate its mix of generation resources. Indiana Electric engages with the communities it serves, its regulators and third-parties in developing its generation transition plan. Recent IRPs have demonstrated Indiana Electric can most cost effectively serve its customers by transitioning its generation fleet to a wider mix of resources, including renewables. For example, Indiana Electric's 2019/2020 IRP identified a preferred portfolio that retires 730 MW of coal-fired generation facilities and replaces these resources with a mix of generating resources composed primarily of renewables, including solar, wind, and solar with storage, supported by dispatchable natural gas combustion turbines including a pipeline to serve such natural gas generation. Indiana Electric is continuing its plan to transition generation resources away from coal-fired generation to a more sustainable portfolio of resources, including renewables. While the IURC does not approve or reject Indiana Electric's IRP, the IURC does comment on the IRP. Indiana Electric is required to obtain a CPCN prior to constructing or acquiring generating resources. Indiana Electric also obtains IURC approval of PPAs and DSM plans to help ensure cost recovery.

Indiana Electric must manage several risks associated with its generation transition plan. The IURC may delay providing comments on an IRP, requiring Indiana Electric to either wait for comments or proceed to implement its IRP without IURC comments. The IURC comments may raise concerns with Indiana Electric's IRP that make it difficult to obtain approval of the generation transition plan if not addressed. There is no guarantee that the IURC will approve Indiana Electric's requests to implement part of its generation transition. If Indiana Electric fails to receive IURC approvals necessary to acquire the projects or resources identified in its IRP, Indiana Electric may not be able to implement its generation transition plan in a timely manner or at all. Additionally, projected changes in how renewable and battery storage resources are accredited to meet MISO's planning reserve margin requirement make it less economic to pursue these resources in the future. In connection with its IRPs, Indiana Electric's determinations with respect to the appropriate mix of generation resources may change from plans that were previously announced. If Indiana Electric is unable to implement its generation transition plan, it may have an adverse effect on CenterPoint Energy's ability to execute on its net zero and GHG emissions reduction goals, its goal to exit the coal plants that Indiana Electric operates, its growth strategy, achieve its financial goals, and otherwise impact results of operations and cash flows.

Even if a generation project is approved, risks associated with the development or construction of any new generation exist, including new legislation or governmental action restricting or delaying new generation, moratorium legislation, the ability to procure resources needed to build at a reasonable cost, scarcity of resources and labor, ability to appropriately estimate costs of new generation, the effects of potential construction delays, project scope changes, and cost overruns and the ability to meet capacity requirements. For example, in January 2025, President Trump signed executive orders that, among other things, temporarily halted certain federal government agencies from issuing approvals, permits and loans for onshore wind projects pending the completion of certain assessments and reviews, and pause the disbursement of funds appropriated through the IRA and the Infrastructure Investments and Jobs Act. As an additional example, the developers of a 130 MW Pike County Solar project informed Indiana Electric that, due to delays in the MISO interconnection queue and inflationary pressures, costs exceeded the agreed upon levels in the BTA. After negotiations, Indiana Electric and the developer were not able to agree upon updated pricing. As a result, on March 15, 2024, Indiana Electric provided notice to the IURC that it was exercising its right to terminate the BTA. Further, tariffs, as well as any new legislation, tariffs, bans, potential retaliatory trade measures taken against the United States or related governmental action, could adversely affect our ability to develop and construct new generation, including our ability to procure the resources needed for such development and construction. For example, on February 6, 2025, the EPC contractor for Indiana Electric's proposed natural gas combustion turbines provided a notice to Indiana Electric that the EPC contractor was identifying the impacts of the proposed tariffs on the project and intended to seek an equitable adjustment to the contract price for the project. For additional information, see "— Disruptions to the global supply..." Furthermore, we have begun to acquire and/or develop additional solar and wind facilities as part of our capital plan.

However, we have not yet entered into definitive agreements with developers for the acquisition and/or development of all of the additional projects, and we face significant competition with other bidders for a limited number of such generation facilities that developers plan to construct and for solar panels. For additional information, see "— Increases in the cost or reduction in supply ..." The number of available projects is further limited by the MISO interconnection queue due to potential interconnection costs that may render projects infeasible. As a result, suitable generation facility project candidates or resources necessary to construct such projects may not be available on terms and conditions we find acceptable, or the expected benefits of a completed facility may not be realized fully or at all, or may not be realized in the anticipated timeframe. If Indiana Electric was unable to meet its generation needs as a result of project delays or cancellations, it would be required to buy the necessary capacity and electricity on the open market. Such open market purchases may result in increased costs and may have an adverse impact on our operations, financial condition, results of operations and cash flows. If we are unable to complete or acquire such generation facilities or resources, or if they do not perform as anticipated, our future growth, financial condition, results of operations and cash flows may be adversely affected.

Houston Electric's receivables are primarily concentrated in a small number of REPs, and any delay or default in payments of these receivables could adversely affect Houston Electric's financial condition, results of operations and cash flows.

Houston Electric's receivables from the distribution of electricity are collected from REPs that supply the electricity. As of December 31, 2024, Houston Electric provided electric delivery service to approximately 67 REPs. Adverse conditions, including, but not limited to, the February 2021 Winter Storm Event or other extreme weather (which may result in abnormal power prices), structural problems in the market served by ERCOT, the impact of pandemic health events or similar occurrences, mismanagement by the REPs, inflation or financial difficulties of one or more REPs, have and may in the future impair the ability of these REPs to pay for Houston Electric's services or cause them to delay such payments. Houston Electric depends on these REPs to remit payments on a timely basis. Applicable PUCT regulations significantly limit the extent to which Houston Electric can apply normal commercial terms to otherwise seek credit protection from firms desiring to provide retail electric service in its service territory, and Houston Electric thus remains at risk for payments relating to services provided prior to any shift to another REP or provider of last resort. Houston Electric's PUCT-approved tariff outlines the remedies available to Houston Electric in the event that a REP defaults on amounts owed. Among the remedies available to Houston Electric are seeking recourse against any cash deposit, letter of credit, or surety bond provided by the REP or implementing mutually agreeable terms with the REP. Another remedy is to require that customers be shifted to another REP or a provider of last resort. Houston Electric thus incurs risk for payments related to services provided prior to the shift to another REP or the provider of last resort. A significant portion of Houston Electric's billed receivables from REPs are due from affiliates of NRG and Vistra Energy Corp. Houston Electric's aggregate billed receivables balance from REPs as of December 31, 2024 was $263 million. Approximately 37% and 21% of this amount was owed by affiliates of NRG and Vistra Energy Corp., respectively. Any delay or default in payment by REPs could adversely affect Houston Electric's financial condition, results of operations and cash flows. If a REP was unable to meet its obligations, it could consider, among various options, restructuring under the bankruptcy laws, in which event such REP might seek to avoid honoring its obligations, and claims might be made regarding prior payments Houston Electric had received from such REP. For example, following the February 2021 Winter Storm Event, multiple REPs filed for bankruptcy. We are currently recording the amounts owed by these REPs as a regulatory asset for bad debt expenses, which is subject to a reasonableness review by the PUCT in our current base rate case. As of December 31, 2024 and 2023, as authorized by the PUCT, CenterPoint Energy and Houston Electric recorded a regulatory asset of $8 million for bad debt expenses resulting from REPs' defaults on their obligations to pay delivery charges to Houston Electric, net of collateral. There is no guarantee that we will be able to recover any or all of the regulatory asset in our next base rate case. See "— Rate regulation of Registrants' Electric ..." For further information on certain of Houston Electric's ongoing regulatory proceedings, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Regulatory Matters" in Item 7 of Part II of this report.

Houston Electric's use of TEEEF is subject to various risks, including failure to obtain and deploy sufficient TEEEF resources, potential performance issues and allegations about Houston Electric's procurement and deployment of the resources (including the planning, execution and effectiveness of the same), regulatory and environmental requirements, and timely recovery of capital.

Following the February 2021 Winter Storm Event, the Texas legislature passed a law, effective September 1, 2021, that allows TDUs, such as Houston Electric, to lease and temporarily operate back-up generation resources during widespread power outages where ERCOT has ordered a TDU to Load Shed or the TDU's distribution facilities are not being fully served by the bulk power system under normal operations. In response to this legislation, Houston Electric entered into two leases for large 27 MW to 32 MW TEEEF (temporary generation) and medium five MW TEEEF. In 2023, the Texas legislature amended the law to allow wider use of TEEEF, including in response to a significant power outage affecting a significant number of distribution customers that has lasted or is expected to last for at least six hours, affecting distribution customers in an area for

which the governor has issued a disaster or emergency declaration, affecting distribution customers served by a radial transmission or distribution facility that creates a risk to public health or safety and that has lasted or is expected to last for at least 12 hours, or creating a risk to public health or safety because it affects a critical infrastructure facility that serves the public. Pursuant to the amendment, the Texas Division of Emergency Management, ERCOT, or the executive director of the PUCT may also determine that a power outage other than one described above is a significant power outage for purposes of use of TEEEF. In response to this amendment, Houston Electric entered into additional leases for small 200-kilowatt to one MW TEEEF.

If Houston Electric is unable to deploy a sufficient number of TEEEF resources in time to respond to a particular event (including as a result of re-leasing TEEEF to third parties or similar transactions, as described further below, or if leasing certain TEEEF becomes prohibited by law, as further described below); if TEEEF resources fail to perform, or are perceived to fail to perform, as intended; if Houston Electric is otherwise unable, or perceived as unable, to provide back-up generation resources and restore power as intended; or if the use of TEEEF resources or their failure to perform causes or is alleged to cause any personal injury, property damage, or other damage or loss due to allegations Houston Electric failed to deploy such units reasonably or effectively and failed to respond to particular power outages, Houston Electric could be subject to claims, demands, litigation, liability, regulatory scrutiny, and loss of reputation. For example, various federal, state and local governmental and regulatory agencies and other entities, such as the Texas Governor's office, the Texas legislature and the PUCT, have called for or are conducting inquiries and investigations into Hurricane Beryl and the efforts made by Houston Electric to prepare for, and respond to, this event, including, among other things, Houston Electric's procurement of TEEEF. Texas Lieutenant Governor Patrick has publicly urged the PUCT to hold Houston Electric, rather than ratepayers, responsible for paying approximately $800 million, which, as detailed below, was the amount the PUCT had previously approved Houston Electric to recover from ratepayers relating to Houston Electric's leasing of TEEEF. Additionally, legislation has been proposed in Texas to, among other things, require the PUCT to review TEEEF leased by TDUs, disallow any leases that do not conform to the terms of the proposed legislation (which include, among other things, requirements relating to the speed with which TEEEF may be deployed), disallow recovery of costs associated with such disallowed leases, and implement a process to refund ratepayers the charges paid for the leasing of certain TEEEF. On August 12, 2024, Texas Attorney General Ken Paxton opened an investigation to evaluate CenterPoint Energy's conduct during Hurricane Beryl, including with respect to its TEEEF resources. There are significant uncertainties around these inquiries, investigations and proposed legislation and potential results and consequences, including with respect to our recovery of costs incurred as a result of Hurricane Beryl and whether any financial penalties will be assessed; whether changes to Houston Electric's system, service territories, operations and/or regulatory treatment will result therefrom; or whether it will be viable for Houston Electric to continue leasing TEEEF. If it is no longer viable for Houston Electric to lease TEEEF at the same or similar scale at which it currently leases such resources and ERCOT issues a directive requiring TDUs to Load Shed or other conditions occur that could be, or are perceived to have the potential to be, addressed by Houston Electric's deployment of TEEEF, Houston Electric could be subject to claims, demands, litigation, liability, regulatory scrutiny and loss of reputation. Additionally, while Houston Electric has insurance coverage and indemnity rights for its use of TEEEF resources, if its insurers or indemnitors fail to meet their indemnity obligations, Houston Electric could be liable for personal injury, property damage, or other damage or loss. For further information, see "— Hurricane Beryl caused severe disruptions...," "— We are involved in numerous legal proceedings..." and "— Our insurance coverage may not..."

As noted above, the legislation allowing TDUs to lease and operate TEEEF prescribes specific and limited use for TEEEF, and Houston Electric's TEEEF have limited generation capacity, such that in future events customers could still be without power despite deployment of TEEEF resources. Further, TEEEF resources are subject to various environmental regulations and permitting requirements, which could have an impact on Houston Electric's ability to use these units. If Houston Electric is not in compliance with any environmental regulation or permitting requirement, Houston Electric could be subject to further potential liability. The use of TEEEF is also subject to various other requirements, and failure to comply with them could subject Houston Electric to additional liability as well as challenges to its use of TEEEF in general.

In April 2023, the PUCT approved revenue recovery of $39 million of TEEEF costs incurred in 2021, and in October 2023, an agreement with intervenors was reached with respect to Houston Electric's second TEEEF filing for revenue recovery of $153 million ($114 million incremental to the prior filing) of TEEEF costs incurred through December 31, 2022, and the agreement was approved by PUCT in February 2024. On September 11, 2024, the TCA filed a complaint with the PUCT requesting that the PUCT modify its rulings with respect to its prior decisions related to the TEEEF filings made in 2022 and 2023. Specifically, TCA requested that the PUCT end cost recovery and return on investment on all the large 32 MW and 5 MW TEEEF units approved in docket 53442. On October 2, 2024, Houston Electric filed a response to the TCA complaint and requested that the complaint be dismissed due to the principles of res judicata and collateral estoppel. On October 8, 2024, TCA supplemented its complaint, and on October 9, 2024, PUCT staff filed a statement of position stating that Houston Electric's response provided a strong argument for dismissal of the complaint, but also stating that it would be prudent to have a thorough legal argument from TCA. On October 10, 2024, PUCT issued Order No. 2 finding the TCA complaint insufficient and

requiring supplemental information or amendment from TCA by October 24, 2024; TCA filed supplemental information on October 24, 2024 and indicated it was prepared to submit supplemental evidence, but only in camera. On October 25, 2024, PUCT issued Order No. 3 in which TCA's request for confidentiality with regard to its membership information was appropriate; Order No. 3 entered a protective order to govern the use of confidential materials in this docket. On November 13, 2024 TCA responded to Order No. 3 and repeated its offer to submit membership information in camera which the ALJ considered to be a motion for rehearing. On November 14, 2024, PUCT issued Order No. 4 which denied the motion to reconsider and extended the prior deadline to file supplemental information to December 13, 2024. On December 16, 2024, PUCT issued Order No. 5 granting waiver of the requirement for informal disposition and soliciting PUCT staff recommendation by January 16, 2025. On January 16, 2025, PUCT staff filed a supplemental recommendation recommending that TCA had not met the requirement to first present its complaint to the City of Houston prior to presenting it to the PUCT. On January 17, 2025 the case was abated until February 28, 2025 to enable TCA to present its complaint to the City of Houston.

Despite the recovery of certain TEEEF costs in the past, there can be no assurance that Houston Electric will seek to or be able to recover certain future TEEEF costs or be able to retain those costs previously approved for recovery. For example, on August 28, 2024, Houston Electric announced its proposal to forego approximately $110 million of profit related to its storm hardening and TEEEF efforts, which would be represented in part by Houston Electric not filing, beginning in 2028, for approximately $40 million in anticipated equity profit associated with Load Shed orientated TEEEF leased by Houston Electric through the remaining regulatory life of the leases in 2032 as new dispatchable generation is likely to come online in the state of Texas as a result of the Texas Energy Fund. Additionally, as noted above, legislation has been proposed in Texas to disallow recovery of costs associated with such disallowed leases and implement a process to refund ratepayers the charges paid for the leasing of certain TEEEF. If Houston Electric is unable to recover or must return any or certain of its TEEEF costs our financial condition, results of operations and cash flows may be adversely affected. For further information, see "— Rate regulation of Registrants' Electric...", "— Our insurance coverage may not..." and "— We are subject to operational..."

On December 19, 2024, Houston Electric announced a proposal to release Houston Electric's 15 large 27 MW to 32 MW TEEEF units to the San Antonio area prior to the summer of 2025. The proposal is intended to help ERCOT address a potential energy shortfall and Load Shed risk and to provide additional electric generation capacity to support growing energy demand in the greater San Antonio region. Under the proposal, Houston Electric would not receive revenue or profit from ERCOT and would also not charge Houston-area customers for these TEEEF units for the period they are in San Antonio serving ERCOT, which is currently expected to be for a period of up to two years. Houston Electric anticipates receiving revenues from one or more future transactions after the period the units are released to temporarily serve the energy need in the San Antonio area, and would therefore plan to continue to not charge customers for these units for future periods. As of the date of the filing of this Form 10-K, Houston Electric estimates that the value of the TEEEF units to be removed from the rate base as a result of the aforementioned proposal will be approximately $375 million. The proposal has not been finalized and is subject to the negotiation of definitive documentation among the relevant parties, as well as being subject to the approval of ERCOT and other stakeholders. It is not certain that mutually agreeable definitive documentation will be entered into at all or that all approvals will be obtained. Assuming that a definitive agreement is executed and that all necessary transaction approvals are received, this proposal is expected to result in a reduction to Houston Electric's customers' bills that Houston Electric would propose to the PUCT in the spring of 2025. Nevertheless, there can be no assurance that Houston Electric will be able to finalize the proposal. If the proposal is not finalized, it may have an adverse effect on our reputation and customer satisfaction, as well as potentially lead to negative consequences from regulatory authorities or other public authorities. Additionally, suitable future transactions may not be available on terms and conditions we find acceptable, or the expected benefits of Houston Electric's proposal to release its 15 large 27 MW to 32 MW TEEEF units to San Antonio or any completed future transactions may not be realized fully or at all, or may not be realized in the anticipated timeframe, which could adversely impact our business, reputation, financial condition, results of operations and cash flows. Finally, if such transactions are successful and thereby result in Houston Electric having fewer TEEEF units to deploy in its own service territory, and if ERCOT issues a directive requiring TDUs to Load Shed or other conditions occur that could be, or are perceived to have the potential to be, addressed by Houston Electric's deployment of TEEEF, Houston Electric could be subject to claims, demands, litigation, liability, regulatory scrutiny and loss of reputation.

Hurricane Beryl caused severe disruptions to our operations, customers and markets in certain of our service territories and could have a material adverse impact on our financial condition, results of operations, cash flows and liquidity.

In July 2024, Hurricane Beryl made landfall in Texas, bringing sustained winds, storm surges and torrential rain, which impacted our operations, customers and personnel in our Texas Gulf Coast markets. Hurricane Beryl caused significant damage to Houston Electric's electric delivery system, resulting in a substantial number of its customers (peaking at more than 2.1 million customers out of 2.8 million customers) being without power, many for extended periods of time.

The total cost for the restoration of Houston Electric's electric delivery facilities as a result of Hurricane Beryl is currently estimated to be $1.1 billion, excluding carrying costs, but such estimate is preliminary and restoration costs could vary from that estimate. Houston Electric believes it is entitled to recover prudently incurred storm restoration costs in accordance with applicable regulatory and legal principles. However, neither the amount nor timing of the recovery is certain. Houston Electric's failure to recover costs incurred as a result of Hurricane Beryl could adversely affect our liquidity, cash flows and financial condition.

Various federal, state and local governmental and regulatory agencies and other entities, such as the Texas Governor's office, the Texas legislature and the PUCT, have called for or are conducting inquiries and investigations into Hurricane Beryl and the efforts made by Houston Electric to prepare for, and respond to, this event, including, among other things, the electric service outage issues. Moreover, additional governmental and regulatory agencies and other entities may conduct such inquiries and investigations, as well. On August 12, 2024, Texas Attorney General Ken Paxton opened an investigation to evaluate CenterPoint Energy's conduct during Hurricane Beryl. Certain government officials have also made public statements calling for, and proposed legislation seeking to require, Houston Electric to pay certain costs related to TEEEF. For more information regarding TEEEF-related risks, see "— Houston Electric's use of TEEEF ..." There are significant uncertainties around these inquiries and investigations and potential results and consequences, including with respect to our recovery of costs incurred as a result of Hurricane Beryl and whether any financial penalties will be assessed or changes to Houston Electric's system, service territories, operations and/or regulatory treatment will result therefrom. If these or other inquiries, investigations or reviews ultimately result in changes to Houston Electric's system, service territories, operations and/or regulatory treatment, such changes could have an adverse impact on our business, results of operations, cash flows and financial condition. Further, on January 22, 2025, a putative shareholder of CenterPoint Energy, Donel Davidson, filed a derivative petition in Harris County District Court, Texas, alleging breach of fiduciary duty and unjust enrichment on behalf of CenterPoint Energy against certain of its current and former directors and officers citing, in part, the topics of these inquiries and investigations. The action seeks to recover damages and other relief from the defendants on behalf of CenterPoint Energy. Additionally, on February 12, 2025, a second putative shareholder of CenterPoint Energy made a demand on the Board to investigate the same basic allegations raised in the derivative petition filed by Donel Davidson.

CenterPoint Energy and Houston Electric are subject to current and potential future litigation and claims arising out of Hurricane Beryl, which litigation and claims could include allegations of, among other things, personal injury, property damage, various economic losses in connection with loss of power, unlawful business practices, and others. As of December 31, 2024, five lawsuits had been filed against CenterPoint Energy and/or Houston Electric in the District Courts of Harris County, including three putative class actions claiming losses due to power outages following Hurricane Beryl. Each class action seeks damages in excess of $100 million for, among other things, business interruption, property damage and loss, cost of repair, loss of use and market value, lost income, nuisance, extreme mental anguish and/or punitive damages. CenterPoint Energy and its subsidiaries have general and excess liability insurance policies that provide coverage for third party bodily injury and property damage claims. Given the nature of some allegations, it is possible that the insurers could dispute coverage for some types of claims or damages that may be alleged by plaintiffs, and CenterPoint Energy has received from two insurers denial of indemnity coverage in the putative class actions based on the failure to supply exclusion. Those insurers have also reserved their rights with respect to coverage in those actions. CenterPoint Energy and Houston Electric intend to continue to pursue all available insurance coverage for all of these matters. While CenterPoint Energy and Houston Electric intend to vigorously defend themselves against the lawsuits, final resolution of these matters, or any potential future claims or liabilities, may require expenditures that may be in excess of established insurance or reserves and may have a material adverse effect on the Registrants' financial condition, results of operation, cash flows and liquidity.

Increases in the cost or reduction in supply of solar energy system components due to tariffs or trade restrictions imposed by the U.S. government may have an adverse effect on our business, financial condition and results of operations.

China is a major producer of solar panels and other solar products. Certain solar cells, modules, laminates and panels from China are subject to various antidumping and countervailing duty rates, depending on the exporter supplying the product, imposed by the U.S. government as a result of determinations the United States was materially injured as a result of such imports being sold at less than fair value and subsidized by the Chinese government. Additionally, in March 2022, the DOC announced it would initiate an investigation into whether imports of solar cells and panels produced in Cambodia, Malaysia, Thailand and Vietnam are circumventing U.S. rules and laws, such as antidumping and countervailing duty rates, which impose a tariff on imports of solar cells and panels manufactured in China. On August 18, 2023, the DOC announced its final determination that five of the eight companies investigated were attempting to bypass U.S. duties by doing minor processing in Southeast Asian countries before shipment to the United States. On May 15, 2024, based on a petition filed by the American Alliance for Solar Manufacturing Trade Committee, the DOC announced the initiation of antidumping and countervailing duty investigations of silicon photovoltaic cells from Cambodia, Malaysia, Thailand, and Vietnam. On October 1, 2024, the DOC's preliminary countervailing duty determination affirmed the petition and established preliminary duty rates. A final

determination is expected in the first quarter of 2025. On November 29, 2024, the DOC announced its preliminary affirmative determination in the antidumping investigation and established preliminary dumping rates. A final determination is expected in the second quarter of 2025. In addition, in December 2021, the United States enacted the Uyghur Forced Labor Prevention Act, which bans goods from China's Xinjiang region due to the use of forced labor. Continuing tensions between the United States and China may lead to restrictions in trade between the two countries or new legislation, tariffs or bans. Furthermore, President Trump has expressed a desire to impose substantial new or increased tariffs on foreign imports into the United States, and in February 2025, President Trump imposed tariffs on several countries (the effectiveness of tariffs imposed on certain countries was subsequently delayed until March 2025) and certain imports into the United States. These tariffs, as well as new legislation, tariffs, bans, potential retaliatory trade measures taken against the United States or related governmental action, could further negatively impact the supply of solar panels. In addition to supply reductions, these or similar duties, legislation and other measures have and may in the future also put upward pressure on prices of these solar energy products, which may reduce our ability to acquire these items in a timely and cost-efficient manner. If we or the developers we are working with are unable to secure such solar energy products in a timely and cost-efficient manner, we may be required to seek additional regulatory review and approvals and/or be forced to delay, downsize and/or cancel solar projects, in which case we may not be able to fully execute on our ten-year capital plan or achieve our net zero and GHG emissions reduction goals. We have experienced project delays due to developers of our projects being unable to acquire solar panels due to supply chain constraints. Additionally, delays or cancellations by developers of third-party solar power facilities expected to interconnect with CenterPoint Energy's and Houston Electric's system may have adverse impacts, such as delayed or reduced potential future revenues. We cannot predict what additional actions the U.S. government may adopt with respect to tariffs, trade agreements or other trade regulations in the future or what actions may be taken by other countries in retaliation for such measures. If the DOC imposes tariffs on solar panels as a result of its findings or other additional measures are imposed, our business, financial condition and results of operations may be adversely affected.

The occurrence of extreme weather events, including winter storms and record hot temperatures, or other causes could lead to additional reforms to the Texas electric market, some measure of which, if implemented, could have an adverse impact on Houston Electric.

During and in the aftermath of the February 2021 Winter Storm Event, the Texas legislature revised applicable statutes and granted the PUCT and ERCOT additional regulatory authority, both oversight and enforcement, that focuses on ensuring ERCOT market participants, including power generation facilities and TDUs (like Houston Electric), have adopted sufficient winterization standards and protection. Houston Electric believes it is in compliance with the requirements applicable to it. If any additional protections are required in the future as a result of additional extreme weather events or other causes, complying with these new protections may increase the cost of electricity, which could adversely affect Houston Electric's results of operations. Any potential decreases in customer usage due to higher electricity prices charged by REPs may not result in increased base rates charged by Houston Electric for its services until its next general base rate proceeding. For further information on Houston Electric's regulatory proceedings, see "— Rate regulation of Registrants' Electric..."

In addition, the PUCT and ERCOT continue to review, among other things, the appropriate reliability standard and market design for the Texas electric market. There are uncertainties whether any further changes will result from these discussions or other efforts. If there are changes to how the Texas electric market is structured or regulated, including as a result of Hurricane Beryl and related investigations, such changes could have an adverse impact on Houston Electric's business, financial condition and results of operations. See Note 7 to the consolidated financial statements for further information.

Natural Gas (CenterPoint Energy and CERC)

Access to natural gas supplies and pipeline transmission and storage capacity are essential components of reliable service for Natural Gas' customers.

Natural Gas depends on third-party service providers to maintain an adequate supply of natural gas and for available storage and intrastate and interstate pipeline capacity to satisfy its customers' needs, all of which are critical to system reliability. Substantially all of Natural Gas' natural gas supply is purchased on intrastate and interstate pipelines. If Natural Gas is unable to secure an independent natural gas supply of its own or if third-party service providers fail to timely deliver natural gas to meet Natural Gas' requirements, the resulting decrease in natural gas supply in Natural Gas' service territories could have an adverse effect on its financial condition, results of operations, cash flows and reputation. Additionally, a significant disruption, whether through reduced intrastate and interstate pipeline transmission or storage deliveries or other events affecting natural gas supply, including, but not limited to, operational failures, hurricanes, tornadoes, floods, severe winter weather conditions, wildfires, acts of terrorism, human error or cyberattacks or changes in legislative or regulatory requirements, could also adversely affect Natural Gas' businesses. Further, to the extent that Natural Gas' natural gas requirements cannot be met

through access to or continued use of existing natural gas infrastructure or if additional infrastructure, including onshore and offshore exploration and production facilities, gathering and processing systems and pipeline and storage capacity is not constructed at a rate that satisfies demand, then Natural Gas' operations could be negatively affected.

Natural Gas is subject to fluctuations in natural gas prices, which could affect the ability of its suppliers and customers to meet their obligations or may impact its operations, which could adversely affect CERC's financial condition, results of operations and cash flows.

Natural Gas is subject to risk associated with changes in the price of natural gas. Significant increases in natural gas prices, such as those experienced during the February 2021 Winter Storm Event, might affect Natural Gas' ability to collect balances due from customers and could create the potential for uncollectible accounts expense to exceed the recoverable levels built into tariff rates. In addition, a sustained period of high natural gas prices could (i) decrease demand for natural gas in the areas in which Natural Gas operates, thereby resulting in decreased sales and revenues and (ii) increase the risk that Natural Gas' suppliers or customers fail or are unable to meet their obligations. An increase in natural gas prices would also increase working capital requirements by increasing the investment that must be made to maintain natural gas inventory levels.

Natural Gas must compete with alternate energy sources, which could result in less natural gas delivered and have an adverse impact on CenterPoint Energy's and CERC's financial condition, results of operations and cash flows.

Natural Gas competes primarily with alternate energy sources such as electricity and other fuel sources. In some areas, intrastate pipelines, other natural gas distributors and natural gas marketers also compete directly with Natural Gas for natural gas sales to end users. In addition, as a result of federal regulatory changes affecting interstate pipelines, natural gas marketers operating on these pipelines may be able to bypass Natural Gas' facilities and market, sell and/or transport natural gas directly to commercial and industrial customers. Any reduction in the amount of natural gas delivered by Natural Gas as a result of competition with alternate energy sources may have an adverse impact on CenterPoint Energy and CERC's financial condition, results of operations and cash flows.

Risk Factors Affecting Regulatory, Environmental and Legal Risks

Rate regulation of Registrants' Electric and Natural Gas businesses may delay or deny their ability to earn an expected return and fully and timely recover their costs.

The Registrants' Electric and Natural Gas businesses are regulated by certain municipalities, state commissions and federal agencies, such as FERC. Their rates are set in comprehensive base rate proceedings (i.e., general rate cases) based on an analysis of their invested capital, their expenses and other factors in a designated test year (often either fully or partially historic), subject to periodic review and adjustments. Each of these rate proceedings is subject to third-party intervention and appeal, and the timing of a general base rate proceeding may be out of the Registrants' control. Houston Electric and CERC, with respect to its Ohio gas territory, each filed rate cases during 2024. The Registrants can make no assurance that their or their subsidiaries respective base rate proceedings will result in requested or favorable adjustments to their rates, in full and timely cost recovery or approval of other requested items, including, among other things, capital structure and ROE. Moreover, these base rate proceedings have caused in certain instances, and in the future could cause, the Registrants' Electric and/or Natural Gas businesses to recover their investments below their requested levels, below the national average return for utilities or below recently approved return levels for other utilities in their respective jurisdictions. For instance, in the 2019 Houston Electric general rate case, Houston Electric filed a base rate case seeking approval for revenue increases of approximately $194 million and a 10.4% ROE, but after entering into a Stipulation and Settlement Agreement filed with the PUCT, Houston Electric received an overall revenue requirement increase of approximately $13 million and a 9.4% ROE. To the extent the regulatory process does not allow the Registrants to make a full and timely recovery of appropriate costs, their financial condition, results of operations and cash flows could be adversely affected. Further, the Registrants or their subsidiaries might be required to implement additional measures, such as the adoption of ring-fencing measures by Houston Electric in connection with its 2019 rate case proceeding. Such additional measures may adversely impact the Registrants' businesses and could have an adverse effect on their financial condition, results of operations and cash flows.

The rates that Registrants' Electric and Natural Gas businesses are allowed to charge may not match their costs at any given time, a situation referred to as "regulatory lag." Regulatory lag has been and may be exaggerated in the future under certain circumstances, such as increased capital investments that are recovered in arrears, like those experienced in 2022, 2023 and early 2024. For example, the MPUC ordered extraordinary gas costs incurred in the February 2021 Winter Storm Event be recovered over a 63-month period from 2022 — 2027 and CERC forego recovery of the associated carrying costs. Though several interim rate adjustment mechanisms have been approved by jurisdictional regulatory authorities and implemented by the Registrants and their subsidiaries to reduce the effects of regulatory lag (for example, CSIA, DCRF, DRR, DSMA, GRIP,

RCRA, RRA, RSP, TCOS and TDSIC), such adjustment mechanisms are subject to the applicable regulatory body's approval, which we cannot assure would be approved, and are subject to certain limitations that may reduce or otherwise impede the Registrants' or their subsidiaries ability to adjust its rates or result in rates below those requested. Therefore, the Registrants can make no assurance filings for such mechanisms will result in favorable adjustments to rates or in full cost recovery. Further, from time to time, the Registrants' regulators approve the issuance of securitization bonds in order to recover certain costs, including costs incurred as a result of severe weather or to recover stranded asset costs. The issuance of these securitization bonds may be delayed. If the issuance of securitization bonds is delayed, we may not be able to recover our costs in a timely manner, which could have an adverse effect on CenterPoint Energy's, CERC's, and Houston Electric's financial condition, results of operations and cash flows.

Inherent in the regulatory process is some level of risk jurisdictional regulatory authorities may challenge the reasonableness or prudency of operating expenses incurred or capital investments made by the Registrants or their subsidiaries and deny the full recovery of their cost of service in rates. From time to time, these reviews and investigations have caused in certain instances, and in the future could cause, the Registrants to recover their costs or investments below their requested levels. For example, in October 2022, the MPUC issued a written order disallowing recovery of approximately $36 million of the $409 million originally requested by CERC in connection with its recovery of costs incurred as a result of the February 2021 Winter Storm Event. Notwithstanding the application of such rate adjustment mechanisms, the regulatory process by which rates are determined is subject to change as a result of legislative processes or rulemakings, as the case may be, and may not always be available or result in rates that will produce recovery of the Registrants' or their subsidiaries' costs or enable them to earn their authorized return. For example, legislation has been proposed in Texas to require the PUCT to review TEEEF leased by TDUs, disallow any leases that do not conform to the terms of the proposed legislation (which include, among other things, requirements relating to the speed with which TEEEF may be deployed), disallow recovery of costs associated with such disallowed leases, and implement a process to refund ratepayers the charges paid for the leasing of certain TEEEF. There can be no assurances that Houston Electric will seek to or be able to recover certain future TEEEF costs or be able to retain those costs previously approved for recovery. For more information regarding TEEEF-related risks, see "— Houston Electric's use of TEEEF ..." Additionally, changes to the rate case or interim adjustment mechanisms could result in an increase in regulatory lag or otherwise impact the Registrants' ability to recover their costs in a timely manner. Additionally, decisions from regulators are typically subject to appeal, and any such appeal could further exacerbate regulatory lag and lead to additional uncertainty associated with rate case proceedings. The regulatory process may also be adversely affected by the political, regulatory and economic environment in the states in which we operate. To the extent the regulatory process does not allow the Registrants to make a full and timely recovery of appropriate costs, their financial condition, results of operations and cash flows could be adversely affected. For further information on rate case proceedings and interim rate adjustment mechanisms, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Regulatory Matters" in Item 7 of Part II of this report.

The regulated utility businesses, and the energy industry as a whole, have experienced a period of rising costs and investments and an upward trend in spending, especially with respect to infrastructure investments, which is likely to continue in the foreseeable future and could result in more frequent rate cases and requests for, and the continuation of, cost recovery mechanisms, all of which could face resistance from customers and other stakeholders especially in a rising cost environment, whether due to inflation, tariffs, high fuel prices or otherwise, and/or in periods of economic decline or hardship. Significant increases in costs could increase financing needs and otherwise adversely affect our business, financial position, results of operation or cash flows.

We face risks related to project siting, financing, construction, permitting, governmental approvals, public opposition, and the negotiation of project development agreements that may impede our development and operating activities.

Houston Electric, Indiana Electric and CERC own, develop, construct, manage and operate electric generation, transmission and distribution facilities or natural gas distribution facilities, as applicable. A key component of our growth is our ability to construct and operate these facilities. As part of these operations, we must periodically apply for licenses and permits from various local, state, federal and other regulatory authorities and abide by their respective conditions. We have previously experienced delays in receiving approval with regards to certain permits and licenses, and have had investigations and enforcement actions with regards to certain of our projects, which have caused delays to our projects in the past. Should we in the future be unsuccessful in obtaining necessary licenses or permits on acceptable terms or resolving third-party challenges to such licenses or permits, should there be a delay in obtaining or renewing necessary licenses or permits, or should regulatory authorities initiate any associated investigations or enforcement actions or impose related penalties or disallowances, our future net income and cash flows could be reduced and our financial condition could be impacted. Any failure to negotiate successful project development agreements for new facilities with third parties could also have adverse effects. Additionally, our projects

have faced and may in the future face opposition from individuals, community organizations, environmental and other activist groups, and other public-interest entities.

We are involved in numerous legal proceedings, the outcomes of which are uncertain, and resolutions adverse to us could negatively affect our financial results.

The Registrants are subject to numerous legal proceedings, including lawsuits and environmental matters in addition to regulatory proceedings, the most significant of which are summarized in Note 14 to the consolidated financial statements. Litigation is subject to many uncertainties; recent trends have shown jury verdicts, settlements and other liability have been significantly increasing; and the Registrants cannot predict the outcome of all matters with assurance. Additionally, under some circumstances, the Registrants could potentially have claims filed against them or incur liabilities associated with assets and businesses no longer owned by them as a result of sales, divestitures or other transfers to third parties who may be unable to fulfill their indemnity obligations to the Registrants. Final resolution of these matters, or any potential future claims or liabilities, may require additional expenditures over an extended period of time that may be in excess of established insurance or reserves and may have an adverse effect on the Registrants' financial results. For further information, see "— Our insurance coverage may not..."

Customers', investors', legislators', regulators' and creditors' opinions of us are affected by many factors, including actual or perceived system reliability, the speed of our response to service interruptions, rates, our ability to successfully execute our capital plan, media coverage and actions by third parties, and negative opinions developed by such stakeholders could harm our reputation and have an adverse impact on our business, results of operations, cash flows and financial condition.

Our results are influenced by the expectations of our customers, investors, legislators, regulators and creditors. Those expectations are based, in part, on the actual or perceived reliability and affordability of our utility services. The speed with which we are able to respond effectively to electric outages, natural gas leaks or events and related accidents and similar interruptions caused by severe weather, physical or cybersecurity incidents or other unanticipated events, as well as our own or third parties' actions or failure to act, can affect customer, regulator and legislator satisfaction. For example, various federal, state and local governmental and regulatory agencies and other entities have called for or are conducting inquiries and investigations into Hurricane Beryl and the efforts made by Houston Electric to prepare for, and respond to, this event, including the associated electric service outage issues. CenterPoint Energy and Houston Electric are also subject to current and potential future litigation and claims arising out of Hurricane Beryl. For more information regarding Hurricane Beryl-related risks, see "— Hurricane Beryl caused severe disruptions..." The level of rates, the timing and magnitude of rate increases, and the volatility of rates can also affect customer satisfaction. Our ability to successfully execute our capital plan may also affect customers', investors', legislators', regulators' and creditors' opinions and actions. Opinions of us can also be affected by media coverage, including social media, which may include information, whether factual or not, that damages our brand and reputation. If customers, investors, legislators, regulators or creditors have or develop a negative opinion of us or our utility services, this could result in, among other things, less favorable legislative and regulatory outcomes or increased regulatory oversight, negative effects on our access to, and the cost of, capital, increased litigation and negative public perception. The foregoing may have adverse effects on our business, results of operations, cash flow and financial condition.

We are subject to operational and financial risks and liabilities arising from environmental laws and regulations, including regulation of CCR, climate change legislation and certain local initiatives that seek to limit fossil fuel usage.

Our operations are subject to stringent and complex laws and regulations pertaining to the environment. As an owner or operator of natural gas pipelines, distribution systems and storage, electric generating facilities and electric transmission and distribution systems, and the facilities that support these systems, we must comply with these laws and regulations at the federal, state and local levels. These laws and regulations can restrict or impact our business activities in many ways, including among others, restricting the use of fossil fuels through future climate legislation or regulation, restricting the use of natural gas-fired appliances in new homes, limiting airborne emissions from generating facilities, restricting the way we manage wastes, including wastewater discharges, air emissions and CCR removal, and requiring remedial action or monitoring to mitigate environmental actions caused by our operations or attributable to former operations. Environmental laws and regulations applicable to our operations are complex and subject to continued uncertainty, and we are subject to risks from changing or conflicting interpretations of existing laws, modifications to existing laws, new laws, and new or modified permit terms. We may need to spend substantial amounts and devote other resources from time to time to comply with these requirements. Further, in the course of operations we have released, and may in the future inadvertently release, various contaminants. Any such releases could have a significant impact on the environment and result in significant fines. Failure to comply with applicable environmental laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including measures taken by individuals and non-governmental organizations seeking to enforce

environmental laws against us or allege a failure to comply with such laws, and could lead to the assessment of monetary penalties, which we have been subject to from time to time, revocation of permits, the imposition of remedial actions, and the issuance of orders enjoining future operations. Certain environmental statutes impose strict joint and several liability for costs required to clean, restore and monitor sites where hazardous substances have been stored, disposed or released. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances or other waste products into the environment.

Regulatory agencies have also adopted, and from time to time consider adopting, new legislation and/or modifying existing laws and regulations to reduce GHGs. There continues to be a wide-ranging policy and regulatory debate, at the state level, nationally and internationally, regarding the possible means for their regulation. The trend in environmental regulation in previous years has been to place more restrictions and limitations on activities that may impact the environment. On April 22, 2021, the United States announced new goals of 50% reduction of economy-wide GHG emissions and 100% carbon-free electricity by 2035, which formed the basis of the United States' commitments announced in Glasgow, Scotland. These renewed climate commitments coming out of the 2021 United Nations Climate Change Conference held in Glasgow and certain executive orders resulted in the development of additional regulations and changes to existing regulations. For example, in May 2023, the EPA proposed regulations setting new GHG emission reduction targets for coal and gas-fired electric generating units that could potentially require additional operating costs or operating restrictions related to operation of Indiana Electric's natural-gas fired units. On April 25, 2024, the EPA released its New Source Performance Standards for Greenhouse Gas Emissions From New, Modified, Reconstructed Fossil Fuel-Fired Units; Emission Guidelines for Greenhouse Gas Emissions From Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule. CenterPoint Energy is currently reviewing this rule. As a distributor and transporter of natural gas and electricity, and a generator of electricity in Indiana, the Registrants' revenues, operating costs and capital requirements could be adversely affected as a result of any regulatory action that would require installation of new control technologies or a modification of its operations or that would have the effect of reducing the consumption of natural gas or electricity or prevent the use of certain fuel types. Nevertheless, on January 20, 2025, President Trump signed an executive order to withdraw the United States from the Paris Agreement, marking a significant shift in U.S. climate policy. Pursuant to the terms of the Paris Agreement, the withdrawal will take effect on January 27, 2026. Additionally, in January 2025, President Trump signed executive orders that, among other things, direct federal executive departments and agencies to initiate a regulatory freeze for certain rules that have not taken effect, pending review by the newly appointed agency head, and call upon the EPA to submit a report on the continuing applicability of its endangerment finding for GHGs under the Clean Air Act and issue guidance on the "social cost of carbon" to consider whether such metric should be eliminated. There can be no assurance as to the amount or timing of future expenditures for environmental compliance or remediation, and actual future expenditures may be greater than the amounts we currently anticipate, which could adversely affect our financial condition, results of operations and cash flows. Likewise, incentives to conserve energy or use energy sources other than natural gas could result in a decrease in demand for our services. For further discussion, see "Business—Environmental Matters" in Item 1 and " —Natural Gas must compete with…"

Evolving investor sentiment related to the use of fossil fuels and initiatives to restrict continued production of fossil fuels may have substantial impacts on CenterPoint Energy's and CERC's electric generation and natural gas businesses. For example, because Indiana Electric currently relies on coal for a portion of its generation capacity, certain financial institutions may choose not to participate in CenterPoint Energy's financing arrangements until future coal generation closures satisfy their thresholds for investments. Further, some investors choose to not invest in CenterPoint Energy due to CenterPoint Energy's and CERC's use of fossil fuels. Also, certain cities in CenterPoint Energy's and CERC's Natural Gas operational footprint have discussed the adoption of initiatives to prohibit the construction of new natural gas facilities that would provide service and focus on electrification. For example, Minneapolis has adopted carbon emission reduction goals in an effort to decrease reliance on fossil natural gas. Certain state and local governments have also passed, or are considering, legislation banning the use of natural gas-fired appliances in new homes, which could affect consumer use of natural gas. Should such bans be enacted within Natural Gas' operational footprint, they could adversely affect consumer demand for natural gas. Any such initiatives and legislation could adversely affect CenterPoint Energy's and CERC's results of operations.

Further, investors, lenders, regulators and other stakeholders are focusing on issues related to environmental justice, which may result in increased scrutiny of our applicable regulatory processes and additional costs of compliance or may adversely affect our reputation. While President Trump in January 2025 signed an executive order calling to terminate all environmental justice offices and positions in the federal government, as well as any environmental justice initiatives, programs or other activities, the focus on environmental justice matters by certain stakeholders may nevertheless provide communities opposed to our operations with greater opportunities to challenge or delay our projects. Opposition to our projects or successful challenges or appeals to permits issued for our projects could result in cancellation of such projects and the loss of investments we have made with respect thereto.

CenterPoint Energy is subject to operational and financial risks and liabilities associated with its sustainability and related activities, including the implementation of and efforts to achieve its GHG emissions reduction goals.

In September 2021, CenterPoint Energy announced its net zero emission goals for Scope 1 and certain Scope 2 emissions by 2035 and a 20-30% reduction in certain Scope 3 emissions by 2035 as compared to 2021 levels. CenterPoint Energy's analysis and plan for execution requires it to make a number of assumptions. These goals and underlying assumptions involve risks and uncertainties and are not guarantees. Should one or more of CenterPoint Energy's underlying assumptions require updating, its actual results and ability to achieve its net zero and GHG emissions reduction goals by 2035 could differ materially from its expectations. Certain of the assumptions that could impact CenterPoint Energy's ability to meet its net zero and GHG emissions reduction goals and the timing thereof include, but are not limited to: GHG emission levels, service territory size and capacity needs remaining in line with Company expectations, including with respect to demand for our services and in relation to the announced sale of CenterPoint Energy's Louisiana and Mississippi natural gas LDC businesses; the ability to appropriately estimate and effectively manage business opportunities from new customers and load growth resulting from, among other things, expansion of data centers, energy export facilities, including hydrogen facilities, electrification of industrial processes and transport and logistics in our service territories; regulatory approvals related to Indiana Electric's generation transition plan and our ability to obtain such approvals; interconnection delays in the footprints of regional transmission organizations and/or interconnection costs; impacts on affordability of customer rates; customer demand for GHG emission free or lower GHG emissions energy; impacts of future regulations or legislation, including those related to the environment and tax (including changes to the renewable energy tax credits enacted in the IRA); impacts of future carbon pricing regulation or legislation, including a future carbon tax; price, availability and regulation of carbon offsets; price of fuel, such as natural gas; cost of energy generation technologies, such as wind and solar, natural gas and storage solutions; adoption of alternative energy by the public, including adoption of electric vehicles; rate of technology innovation with regards to alternative energy resources; CenterPoint Energy's ability to implement its modernization plans for its pipelines and facilities; the ability to complete and timely implement generation alternatives, such as solar and wind generation, to Indiana Electric's coal generation and retirement or fuel conversion dates of Indiana Electric's coal facilities by 2035; the ability to construct and/or permit new natural gas pipelines; the ability to procure resources needed to build at a reasonable cost, the lack of or scarcity of resources and labor, any project cancellations, construction delays or overruns (including as a result of tariffs, legislation, bans, retaliatory trade measures taken against the United States or related governmental action) and the ability to appropriately estimate costs of new generation; impact of any supply chain disruptions; changes in applicable standards, metrics, methodologies or frameworks; and enhancement of energy efficiencies. Our businesses may face increased scrutiny from investors, governmental authorities and other stakeholders related to our sustainability and human capital management activities, including the goals, targets, and objectives we announce, our methodologies and timelines for pursuing them, our progress towards achieving them, and related disclosures. We could also face challenges with managing conflicting requirements and our various stakeholders' expectations. If our sustainability practices do not align with investor or other stakeholder expectations and standards, which continue to evolve, vary, and sometimes conflict, our reputation, our ability to attract or retain employees, and our attractiveness as an investment or business partner could be negatively affected. Similarly, our failure or perceived failure to pursue, fulfill or demonstrate meaningful progress towards our sustainability-focused goals, targets, and objectives, to comply with or otherwise meet ethical, environmental or other standards, regulations, or expectations, which may be varied or conflicting, or to satisfy various reporting standards with respect to these matters (including if there are real or perceived inaccuracies in the data and information we report or if we are exposed to allegations that certain public statements regarding sustainability-related matters are false and misleading "greenwashing" campaigns), within the timelines we announce, or at all, could adversely affect our business or reputation, as well as expose us to government enforcement actions and private litigation.

Developing and implementing plans for compliance with voluntary climate commitments can lead to additional capital, personnel and operation and maintenance expenditures and could significantly affect the economic position of existing facilities and proposed projects. To the extent that we believe any of these costs are recoverable in rates, cost recovery could be resisted by our regulators and our regulators might attempt to deny or defer timely recovery of these costs. Moreover, we cannot predict the ultimate impact of achieving our emissions reduction goals, or the various implementation aspects, on our system reliability or our financial condition and results of operations.

We are subject to regulatory compliance and proceedings, which could result in higher costs for system improvements, as well as fines or other sanctions.

Houston Electric and Indiana Electric are members of ERCOT and MISO, respectively, which serve the electric transmission needs of their applicable regions. As a result of their respective participation in ERCOT and MISO, Houston Electric and Indiana Electric do not have sole operational control over their transmission facilities and are subject to certain costs for improvements to these regional electric transmission systems. In addition, FERC has jurisdiction with respect to ensuring the reliability of electric transmission service, including transmission facilities owned by Houston Electric and other

utilities within ERCOT and Indiana Electric and other utilities within MISO, respectively. FERC has designated NERC as the ERO to promulgate standards, under FERC oversight, for all owners, operators and users of the bulk power system. FERC has approved the delegation by NERC of authority for reliability in ERCOT to the Texas RE, a Texas non-profit corporation, and for reliability in the portion of MISO that includes Indiana Electric to ReliabilityFirst Corporation, a Delaware non-profit corporation. Compliance with mandatory reliability standards may subject Houston Electric and Indiana Electric to higher operating costs and may result in increased capital expenditures, which may not be fully recoverable in rates. While Houston Electric and Indiana Electric have received minor fines in the past for noncompliance, if Houston Electric or Indiana Electric were to be found to be in noncompliance with applicable mandatory reliability standards again, they would be subject to sanctions, including potential monetary penalties, which could range as high as over a million dollars per violation per day, and non-monetary penalties, such as having to file a mitigation plan to prevent recurrence of a similar violation and having certain milestones in such plan tracked.

Additionally, compliance with existing and potential new regulations related to CERC's operation and maintenance of natural gas infrastructure could result in significant costs. The PHMSA is responsible for administering the DOT's national regulatory program to assure the safe transportation of natural gas, petroleum and other hazardous materials by pipelines. The PHMSA continues to develop regulations and other approaches to risk management to assure safety in design, construction, testing, operation, maintenance and emergency response of natural gas pipeline infrastructure. We have programs in place to comply with regulations related to CERC's operation and maintenance of natural gas infrastructure, and we systematically monitor and renew infrastructure over time; however, CERC has received minor fines in the past for noncompliance, and a significant incident or material finding of non-compliance in the future could result in penalties and higher costs of operations.

Our businesses may be adversely affected by the intentional misconduct of our employees.

We are committed to living our core values of safety, integrity, accountability, initiative and respect and complying with all applicable laws and regulations. Despite that commitment and efforts to prevent misconduct, it is possible for employees to engage in intentional misconduct, fail to uphold our core values, and violate laws and regulations for individual gain through contract or procurement fraud, misappropriation, bribery or corruption, fraudulent related-party transactions and serious breaches of our Ethics and Compliance Code and other policies. If such intentional misconduct by employees should occur, it could result in substantial liability, higher costs, increased regulatory scrutiny and negative public perceptions, any of which could have an adverse effect on our financial condition, results of operations and cash flows. From time to time, including as part of our Ethics and Compliance program's efforts to detect misconduct, we become aware of and expect to continue to become aware of instances of employee misconduct, which we investigate, remediate and disclose as appropriate and proportionate to the incident.

Risk Factors Affecting Financial, Economic and Market Risks

Disruptions to the global supply chain may lead to higher prices for goods and services and impact our operations, which could have an adverse impact on our ability to execute our capital plan and on our financial condition, results of operations and cash flows.

The global supply chain has experienced disruptions due to a multitude of factors, such as geopolitical and economic uncertainty, regulatory and policy instability, import tariffs and trade agreements, the COVID-19 pandemic, labor shortages, resource availability, long lead time, manufacturer production limitations, delivery delays, inflation, severe weather events and disruptions to internal or international shipping, including as a result of armed conflicts, and these disruptions have adversely impacted the utility industry. We, as well as other companies in our industry, have experienced supply chain disruptions, as well as increased prices, and we may continue to experience this in the future. For example, President Trump has expressed a desire to impose substantial new or increased tariffs and, in February 2025, imposed tariffs on several countries (the effectiveness of tariffs imposed on certain countries was subsequently delayed until March 2025) and certain imports into the United States. On February 6, 2025, the EPC contractor for Indiana Electric's proposed natural gas combustion turbines provided a notice to Indiana Electric that the EPC contractor was identifying the impacts of the proposed tariffs on the project and intended to seek an equitable adjustment to the contract price for the project. These tariffs, as well as any new legislation, tariffs, bans, potential retaliatory trade measures taken against the United States or related governmental action, could increase or cause volatility in the cost of and negatively impact our ability to procure materials, supplies (such as natural gas) or services necessary for our business and capital plan, lead to a scarcity of resources and labor necessary for our business and capital plan, further extend lead time or otherwise negatively impact the supply chain. Examples of materials necessary for the transmission and distribution of power we and our industry have experienced difficulties in procuring include transformers, wires, cables, meters, poles and solar panels. If the supply chain disruption persists or worsens, we may experience difficulties in procuring these resources and others necessary to operate our businesses in the future. As a result, we may not be able to procure the resources, including labor, needed to timely perform storm restoration activities, fully execute on our ten-year capital plan and/

or achieve our net zero emission and GHG emissions reduction goals. Moreover, inflation and high interest rates have contributed to increased prices for materials and services experienced by us and other companies in our industry and, if such conditions continue, they may have adverse effects on our business, results of operations, cash flow and financial condition. Even if we are able to procure the necessary resources, we might not be able to do so at a reasonable cost or in a timely manner which could result in project cancellations or scope changes, delays, cost overruns and under-recovery of costs. If we are unable to fully execute on capital plans, our financial condition, results of operations and cash flows may be adversely affected.

If we are unable to arrange future financings on acceptable terms, our ability to finance our capital expenditures or refinance outstanding indebtedness could be limited.

Our businesses are capital intensive, and we rely on various sources to finance our capital expenditures. For example, we depend on (i) long-term debt, (ii) borrowings through our revolving credit facilities and, for CenterPoint Energy and CERC, commercial paper programs and (iii) if market conditions permit, issuances of additional shares of common stock or shares of preferred stock by CenterPoint Energy. We may also use such sources to refinance any outstanding indebtedness as it matures. Additionally, from time to time, our operating subsidiaries, including Houston Electric and CERC, may rely on intercompany borrowings from CenterPoint Energy that may be sourced from CenterPoint Energy's external financings. As of December 31, 2024, CenterPoint Energy had $21 billion of outstanding indebtedness on a consolidated basis, which included $324 million of non-recourse Securitization Bonds. For information on outstanding indebtedness of CenterPoint Energy, Houston Electric and CERC as well as future maturities, see Note 12 to the consolidated financial statements. If we are unable to arrange future financings on acceptable terms, our ability to finance our capital expenditures, including our ten-year capital plan (which has increased to nearly $47.5 billion through 2030), or refinance our outstanding indebtedness could be limited. Our future financing activities may be significantly affected by, among other things:

- general economic and capital market conditions, including inflation;
- credit availability from financial institutions and other lenders;
- investor confidence in us and the markets in which we operate;
- the future performance of our businesses;
- maintenance of acceptable credit ratings;
- actions from the Federal Reserve, including changes in interest rates and unanticipated actions;
- market expectations regarding our future earnings and cash flows;
- investor willingness to invest in companies associated with fossil fuels;
- our ability to access capital markets on reasonable terms;
- timing of future securitizations by jurisdictions in which we operate; and
- provisions of relevant securities laws.

The Registrants' current credit ratings and any changes in credit ratings in 2024 and to date in 2025 are discussed in "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Other Matters — Impact on Liquidity of a Downgrade in Credit Ratings" in Item 7 of Part II of this report. These credit ratings may not remain in effect for any given period of time and one or more of these ratings may be reduced or withdrawn by a rating agency. The Registrants note these credit ratings are not recommendations to buy, sell or hold their securities. Each rating should be evaluated independently of any other rating. Any future reduction or withdrawal of one or more of the Registrants' credit ratings could have an adverse impact on their ability to access capital on acceptable terms. For example, if CERC's credit rating were to decline, it may have an adverse impact on the cost of borrowings and, in extraordinary market conditions, it may limit the ability to access the debt capital markets. Additionally, CERC might be required to post collateral under its shipping arrangements or to purchase natural gas. If a credit rating downgrade and the resultant cash collateral requirement were to occur at a time when CERC was experiencing significant working capital requirements or otherwise lacked liquidity, CERC's financial condition, results of operations and cash flows could be adversely affected.

CenterPoint Energy is a holding company that derives all of its operating income from, and holds substantially all of its assets through, its subsidiaries. As a result, CenterPoint Energy depends on the performance of and distributions from its subsidiaries to meet its payment obligations and to pay dividends on its common stock, and provisions of applicable law or contractual restrictions could limit the amount of those distributions.

CenterPoint Energy derives all of its operating income from, and holds substantially all of its assets through, its subsidiaries. Similarly, as a result of the Restructuring, CERC derives a significant portion of its operating income from and holds a significant portion of its assets through its subsidiaries, including Indiana Gas and CEOH. As a result, CenterPoint Energy, and to a lesser extent, CERC, depend on the performance of and distributions from their respective subsidiaries to meet their respective payment obligations and to pay dividends on their respective common stock. In general, CenterPoint Energy's and CERC's subsidiaries are separate and distinct legal entities and have no obligation to provide them with funds for their

respective payment obligations, whether by dividends, distributions, loans or otherwise. In addition, provisions of applicable law, such as those limiting the legal sources of dividends, limit CenterPoint Energy's and CERC's respective subsidiaries' ability to make payments or other distributions to CenterPoint Energy or CERC, and their respective subsidiaries could agree to contractual restrictions on their ability to make payments or other distributions. Further, as part of the agreement resulting from Houston Electric's 2019 base rate case, Houston Electric filed a base rate proceeding in 2024. Further ring-fencing measures could be imposed on Houston Electric in the future through legislation or PUCT rules or orders. While current ring-fencing measures have not impacted Houston Electric's ability to pay dividends to CenterPoint Energy, the imposition of any additional measures impacting CenterPoint Energy's ability to receive dividends from Houston Electric could adversely affect CenterPoint Energy's cash flows, credit quality, financial condition and results of operations. Any such adverse effect on CenterPoint Energy could also adversely affect Houston Electric's and/or CERC's cash flows, credit quality, financial condition and results of operations as CenterPoint Energy may not be able to financially support Houston Electric and/or CERC if and when necessary.

CenterPoint Energy's right to receive assets of any subsidiary, and therefore the right of its creditors to participate in those assets, are structurally subordinated to the claims of that subsidiary's creditors, including trade creditors. In addition, even if CenterPoint Energy were a creditor of any subsidiary, its rights as a creditor would likely be effectively subordinated to any security interest in the assets of that subsidiary and any senior indebtedness of the subsidiary.

CenterPoint Energy's previously owned Energy Systems Group business has performance and warranty obligations, some of which are guaranteed by CenterPoint Energy.

On June 30, 2023, CenterPoint Energy closed the sale of its Energy Systems Group business. Prior to June 30, 2023 and as part of the normal course of its business, Energy Systems Group issued performance bonds and other forms of assurance that committed it to operate facilities, pay vendors or subcontractors and support warranty obligations. As the parent company prior to the closing of the sale, CenterPoint Energy or Vectren guaranteed certain of its subsidiaries' commitments. When Energy Systems Group was wholly owned by CenterPoint Energy, these guarantees did not represent incremental consolidated obligations, but rather, these guarantees represented guarantees of Energy Systems Group's obligations to allow it to conduct business without posting other forms of assurance. Neither CenterPoint Energy nor Vectren has been called upon to satisfy any obligations pursuant to these parental guarantees to date but may be required to do so in the future. For further information, see Note 14(c) to the consolidated financial statements.

An impairment of goodwill, long-lived assets or equity method investments or a fair value adjustment could reduce our earnings.

Long-lived assets are reviewed for impairment whenever events or changes in circumstances indicate the carrying value may not be recoverable. Goodwill is tested for impairment at least annually, as well as when events or changes in circumstances indicates the carrying value may not be recoverable. While CenterPoint Energy has identified and recorded goodwill impairments in the past, no impairments to goodwill were recorded during the years ended December 31, 2024, 2023, and 2022. See Note 6 to the consolidated financial statements for further information. Should the annual goodwill impairment test or another periodic impairment test or an observable transaction indicate the fair value of our assets is less than the carrying value, we would be required to take a non-cash charge to earnings with a correlative effect on equity, increasing balance sheet leverage as measured by debt to total capitalization. A non-cash impairment charge or fair value adjustment could adversely impact our financial condition and results of operations.

If CenterPoint Energy redeems the ZENS prior to their maturity in 2029, its ultimate tax liability and redemption payments would result in significant cash payments, which would adversely impact its cash flows and liquidity. Similarly, a significant amount of exchanges of ZENS by ZENS holders could adversely impact CenterPoint Energy's cash flows and liquidity.

CenterPoint Energy has approximately $828 million principal amount of ZENS outstanding as of December 31, 2024. CenterPoint Energy owns shares of ZENS-Related Securities equal to approximately 100% of the reference shares used to calculate its obligation to the holders of the ZENS. CenterPoint Energy may redeem all of the ZENS at any time at a redemption amount per ZENS equal to the higher of the contingent principal amount per ZENS $9 million in the aggregate, or $0.62 per ZENS, as of December 31, 2024, or the sum of the current market value of the reference shares attributable to one ZENS at the time of redemption. In the event CenterPoint Energy redeems the ZENS, in addition to the redemption amount, it would be required to pay deferred taxes related to the ZENS. CenterPoint Energy's ultimate tax liability related to the ZENS and ZENS-Related Securities continues to increase by the amount of the tax benefit realized each year. If the ZENS had been redeemed on December 31, 2024, deferred taxes of approximately $802 million would have been payable in 2024, based on 2024 tax rates in effect. In addition, if all the shares of ZENS-Related Securities had been sold on December 31, 2024 to fund the aggregate

redemption amount, capital gains taxes of approximately $84 million would have been payable in 2024. Similarly, a significant amount of exchanges of ZENS by ZENS holders could adversely impact CenterPoint Energy's cash flows and liquidity. This could happen if CenterPoint Energy's creditworthiness were to drop, the market for the ZENS were to become illiquid, or for some other reason. While funds for the payment of cash upon exchange of ZENS could be obtained from the sale of the shares of ZENS-Related Securities CenterPoint Energy owns or from other sources, ZENS exchanges result in a cash outflow because tax deferrals related to the ZENS and ZENS-Related Securities shares would typically be disposed when ZENS are exchanged and ZENS-Related Securities shares are sold.

Our potential business strategies and strategic initiatives, including merger and acquisition activities and the disposition of assets or businesses, may not be completed or perform as expected, adversely affecting our financial condition, results of operations and cash flows.

Our financial condition, results of operations and cash flows depend, in part, on our management's ability to implement our business strategies successfully and realize the anticipated benefits therefrom. In 2021, we announced our strategic goals for CenterPoint Energy, including our ten-year capital plan, and net zero and GHG emissions reduction goals. Our strategic goals are subject to the risks described in this section and various assumptions. These assumptions may require updating or we may not be able to execute on these strategic goals in a timely manner or at all. If we are unable to execute on our strategic goals, including our ten-year capital plan, the benefits therefrom may not be fully realized, if at all, and our reputation may be adversely affected.

From time to time we have made, and may continue to make, acquisitions or divestitures of, or other similar transactions involving, businesses and assets, such as our announced sale of our Louisiana and Mississippi natural gas LDC businesses, Houston Electric's proposed release of its 15 large 27 MW to 32 MW TEEEF units to the San Antonio area and other potential future subleasing of TEEEF and our completed sale of our Energy Systems Group business, form joint ventures or undertake restructurings, such as the Restructuring. However, suitable acquisition candidates or potential buyers may not continue to be available on terms and conditions we find acceptable, or the expected benefits of completed acquisitions, dispositions or similar transactions may not be realized fully or at all or may not be realized in the anticipated timeframe. If we are unable to make acquisitions, or if those acquisitions do not perform as anticipated, our future growth may be adversely affected. Further, any completed or future acquisitions, dispositions or similar transactions involve substantial risks, including the following:

- acquired businesses or assets, or other business strategies and strategic initiatives may not produce revenues, earnings or cash flow at anticipated levels;
- acquired businesses or assets, or other business strategies and strategic initiatives could have environmental, permitting or other problems for which contractual protections prove inadequate;
- we may assume liabilities that were not disclosed to us, that exceed our estimates, or for which our rights to indemnification from the seller are limited;
- we may be unable to integrate acquired businesses successfully and realize anticipated economic, operational and other benefits in a timely manner, which could result in substantial costs and delays or other operational, technical or financial problems;
- acquisitions, dispositions or similar transactions, or the pursuit of such transactions, including any separation or disentanglement efforts or requirements, such as the provision of transition services, could disrupt our ongoing businesses, distract management, divert resources and make it difficult to maintain current business standards, controls and procedures; and
- we may not receive regulatory approvals necessary to complete an acquisition, disposition or similar transaction in a timely manner or at all.

On February 19, 2024, CenterPoint Energy, through its subsidiary CERC Corp., entered into the LAMS Asset Purchase Agreement to sell its Louisiana and Mississippi natural gas LDC businesses. The transaction is expected to close in the first quarter of 2025. For further information, see Note 4 to the consolidated financial statements. We can make no assurances regarding the completion of this sale, which could be subject to delays or otherwise not consummated.

Changing demographics, poor investment performance of pension plan assets and other factors adversely affecting the calculation of pension liabilities could unfavorably impact our financial condition, results of operations and liquidity.

CenterPoint Energy and its subsidiaries maintain qualified defined benefit pension plans covering certain of its employees. Costs associated with these plans are dependent upon a number of factors including the investment returns on plan assets, the level of interest rates used to calculate the funded status of the plan, contributions to the plan, the number of plan participants and government regulations with respect to funding requirements and the calculation of plan liabilities. Funding requirements may increase and CenterPoint Energy may be required to make unplanned contributions in the event of a decline in the market

value of plan assets, a decline in the interest rates used to calculate the present value of future plan obligations, or government regulations that increase minimum funding requirements or the pension liability. In 2023 and 2022, CenterPoint Energy had a settlement expense for its pension plans as a result of an increase in eligible employee retirements and pension plan distributions. See Note 8 to the consolidated financial statements for further information. In addition to affecting CenterPoint Energy's funding requirements, these factors could adversely affect our financial condition, results of operations and liquidity.

We may be significantly affected by changes in federal income tax laws and regulations, including any comprehensive federal tax reform legislation.

Our businesses are impacted by U.S. federal income tax policy. The TCJA, CARES Act, and the IRA significantly changed the U.S. Internal Revenue Code, including taxation of U.S. corporations, by among other things, reducing the federal corporate income tax rate, limiting interest deductions, altering the expensing of capital expenditures, enacting a new CAMT, and expanding federal tax credits for cleaner energy production. Based on guidance available as of December 31, 2024, the Registrants will be subject to the CAMT included in the IRA.

The interpretive guidance issued by the IRS and state tax authorities may be inconsistent with our interpretation and the legislation could be subject to amendments, which could lessen or increase certain impacts of the legislation. In addition, while certain regulators have allowed the Registrants to recover certain costs associated with the CAMT in the past, the retail regulatory treatment of the expanded tax credits and CAMT could impact the Registrants' future cash flows, and this legislation could result in unintended consequences not yet identified that could have an adverse impact on the Registrants' financial results and future cash flows.

Further federal tax reform legislation, including legislation proposed by the new presidential administration, could be enacted that may significantly change the federal income tax laws applicable to domestic businesses, including changes that may impact investment incentives and deductions for depreciation and interest, among other deductions. While the details of the Trump Administration's potential tax reform have not been announced as of the date of the filing of this Form 10-K, during his 2024 presidential campaign, President Trump outlined several intended reforms, including reducing the corporate tax rate for domestic oil and gas production, repealing or revising the IRA, extending certain provisions of the TCJA and imposing new tariffs. In January 2025, President Trump signed an executive order that, among other things, pauses the disbursement of funds appropriated through the IRA. In February 2025, President Trump imposed tariffs on various countries (the effectiveness of tariffs imposed on certain countries was subsequently delayed until March 2025) and certain imports into the United States. New federal tax reform legislation and the implementation of new or increased tariffs could lead to increases in market interest rates, a decrease in U.S. economic growth, and/or recession. Additionally, the change in administration and the expiring tax cuts in the TCJA could result in the repeal of or changes to the IRA, including renewable energy tax credits enacted in the IRA, and these changes could impact CenterPoint Energy's net zero and GHG emissions reduction goals. While CenterPoint Energy and its subsidiaries cannot assess the overall impact of any such potential legislation or other actions on our businesses, it is possible that our financial condition, results of operations or cash flows could be negatively impacted. Furthermore, with any enacted federal tax reform legislation, it is uncertain how state commissions and local municipalities may require us to respond to the effects of such tax legislation, including determining the treatment of EDIT and other increases and decreases in our revenue requirements. As such, potential regulatory actions in response to any enacted tax legislation could adversely affect our financial condition, results of operations and cash flows.

Risk Factors Affecting Safety and Security Risks

The Registrants' businesses have safety risks.

The Registrants' facilities and distribution and transmission systems have been and may in the future be involved in incidents that result in injury, death, or property loss to employees, customers, third parties (including vendors, suppliers and contractors), or the public. Although the Registrants have insurance coverage for many potential incidents, depending upon the nature and severity of any incident, they could experience financial loss, claims and litigation, damage to their reputation, and negative consequences from regulatory authorities or other public authorities. Further, certain CenterPoint Energy employees who work in the field have experienced threats of violence during the performance of their work. Threats of violence, actual violence and other concerns may result in employees and third parties supporting the work of the Registrants being unable or unwilling to complete critical functions, which could adversely affect our businesses, financial condition and results of operations, and could make it harder to, among other things, recruit and retain certain employees.

Cyberattacks, physical security breaches, acts of terrorism or other disruptions could adversely impact our reputation, financial condition, results of operations and cash flows.

We are subject to cyber and physical security risks related to our information technology systems, operational technology, network infrastructure, and other technology and facilities used to conduct almost all of our businesses. The operation of our electric generation, transmission and distribution systems is dependent on the physical interconnection of our facilities, as well as communications among the various components of our systems and third-party systems. Further, certain of the various internal systems we use to conduct our businesses are highly integrated. Consequently, a cyberattack or unauthorized access in any one of these systems could potentially impact the other systems. Similarly, our business operations, including our transmission systems and natural gas pipelines, are part of an interconnected system. Disruption of those systems, or our ability to communicate with those systems, whether caused by physical disruption such as storms or other natural disasters, by failure of equipment or technology or by man-made events, such as cyberattacks or acts of terrorism, may disrupt our ability to conduct operations and control assets and negatively impact our business.

The sophistication of cybersecurity threats, including those leveraging AI, continues to increase, and the controls and preventative actions we take to reduce the risk of cybersecurity incidents and protect our systems, including the regular testing of our cybersecurity incident response plan, may be insufficient. In addition, new technology that could result in greater operational efficiency, such as our use of AI, may further expose our computer systems to the risk of cybersecurity incidents. Cyberattacks, including phishing attacks and threats from the use of malware, ransomware and viruses or malicious code, and unauthorized access could also result in the loss, or unauthorized use, of confidential, proprietary or critical infrastructure data or security breaches of other information technology systems that could disrupt operations and critical business functions, adversely affect reputation, impact our customers, increase costs and subject us to possible legal claims and liability. While we have implemented and maintain a cybersecurity program designed to protect our information technology, operational technology, and data systems from such attacks, our cybersecurity program does not prevent all breaches or cyberattack incidents. Publicly known vulnerabilities in our information technology and operational technology environments may not be remediated before an adversary could discover or exploit them. Attackers can also exploit new, unknown vulnerabilities (e.g., zero-day vulnerabilities) and vulnerabilities where a patch or other remediation measure is not yet available. We have experienced an increase in the number of attempts by external parties to access our networks or our company data without authorization. We have also experienced, and expect to continue to experience, cyber intrusions and attacks to our information systems and those of third parties, including vendors, suppliers, contractors and quasi government entities who perform certain services for us or administer and maintain our sensitive information. These prior intrusions and attacks have not had a material impact on our business, results of operations, or financial condition. Because technology is increasingly complex and cyberattacks are increasingly sophisticated and more frequent, there is a risk such incidents could have an adverse effect on us in the future. The risk of a disruption or breach of our operational technology systems, or the compromise of the data processed in connection with our operations, through a cybersecurity breach or ransomware attack, has increased as attempted attacks have advanced in sophistication and number around the world. Our insurance coverage may not be sufficient to cover all costs associated with cybersecurity threats or incidents.

Our continued efforts to integrate, consolidate and streamline our operations have also resulted in increased reliance on current and recently completed projects for technology systems. A failure to maintain and enhance existing information technology systems could adversely affect our operations. Procedures we implement to protect our systems may be insufficient to protect and safeguard against unauthorized access to secured data. A failure of our technologies or procedures, or our inability to support and integrate these technologies across our subsidiaries, could materially and adversely impact our operations, diminish customer confidence and our reputation, materially increase the costs we incur to protect against these risks and subject us to possible financial liability or increased regulation or litigation.

We depend on the secure operations of our physical assets to transport the energy we deliver and our information technology to process, transmit and store electronic information, including information and operational technology we use to safely operate our energy transportation systems. Security breaches, attacks on our infrastructure and facilities, including against the Registrants or as a means to harm a third-party by disrupting the transmission and distribution of energy, or acts of terrorism, including by foreign or domestic actors, could expose our business to a risk of loss, misuse or interruption of critical physical assets or information and functions that affect our operations, as well as potential data privacy breaches and loss of protected personal information and other sensitive information, such as Critical Energy Infrastructure Information. Such losses could result in operational impacts, damage to our assets, public or personal safety incidents, impacts to our customers, damage to the environment, reputational harm, competitive disadvantage, regulatory enforcement actions, litigation and a potential adverse effect on our operations, financial condition, results of operations and cash flows. There is no certainty that costs incurred related to actual or thwarted cyberattacks, or for the safeguarding against such security threats, will be recoverable through rates.

Compliance with and changes in cybersecurity laws and regulations have a cost and operational impact on our business, and failure to comply with such requirements could adversely impact our reputation, financial condition, results of operations and cash flows.

Cyberattacks are becoming more sophisticated, and U.S. government warnings have indicated infrastructure assets, including pipelines and electric generation and infrastructure, may be specifically targeted by certain groups. Regulators have adopted numerous rules and regulations regarding cybersecurity. As a result, CenterPoint Energy continues to take measures to comply with the TSA pipeline security directive requirements applicable to critical pipeline owners and operators. These security directives require CenterPoint Energy to establish, implement and assess a TSA-approved Cybersecurity Implementation Plan that describes the security measures maintained to comply with relevant provisions of the security directives. CenterPoint Energy is also subject to standards enacted by NERC and enforced by FERC regarding protection of critical infrastructure assets required for operating North America's bulk electric system. We may be required to expend significant additional resources and costs to respond to cyberattacks, to continue to modify or enhance our protective measures, or to assess, investigate and remediate any critical infrastructure security vulnerabilities. There is no certainty that such costs incurred will be recovered through rates. We also face increasing and evolving disclosure and reporting obligations related to cybersecurity events, and there is no certainty that we will be able to meet existing or future disclosure obligations and avoid the risk of potentially having our disclosures misinterpreted when made. National security or public safety considerations may further affect, or in some instances prevent, our public disclosure of a cybersecurity incident in certain circumstances. Any failure to remain in compliance with these government regulations or failure in our cybersecurity protective measures may result in enforcement actions which may have an adverse effect on our reputation, financial condition, results of operations and cash flows.

Failure to maintain the security of personal information could adversely affect us.

In connection with our businesses, we and our third parties (vendors, suppliers, and contractors) collect and retain personal information (for example, information of our customers, shareholders, suppliers and employees), and there is an expectation that we and such third parties will adequately protect that information. The regulatory environment surrounding information security and data privacy continues to evolve and is increasingly demanding. New laws and regulations governing data privacy and the unauthorized disclosure of confidential information pose increasingly complex compliance challenges and elevate our costs. Any failure by us to comply with these laws and regulations, including as a result of a security or privacy breach, could result in significant costs, fines and penalties and liabilities for us. The systems we have implemented to protect our information technology, operational technology, and data systems from attacks cannot prevent all security breaches, and the systems we have implemented to manage and protect personal information cannot prevent all privacy breaches. We and some of our third parties that maintain personal information have experienced, and expect to continue to experience, data privacy incidents and breaches; however, to date, we have not experienced a material data privacy incident or breach. A significant theft, loss or fraudulent use of the personal information we maintain, or failure of our vendors, suppliers and contractors to use or maintain such data in accordance with contractual provisions and other legal requirements, could adversely impact our reputation and could result in significant costs, fines and penalties and liabilities for us. Additionally, if we acquire a company that has violated or is not in compliance with applicable data protection privacy, we may incur significant liabilities and penalties as a result.

We may not be successful in our adoption, development and deployment of AI, which could adversely affect our business, reputation, or financial results.

We are using and exploring the further use of AI, including generative AI, and its ability to enhance the services we offer to the communities we serve. There are significant risks involved in developing and deploying AI, and ineffective or inadequate development or deployment of AI practices by us or our third-parties (vendors, suppliers, and contractors) could result in unintended consequences. We contract with third-parties that use AI in products and services they provide and we may not have full control or visibility over the quality, performance, security or compliance of the products and services that incorporate AI-related technology. Additionally, the use of AI may not enhance our services or be beneficial to our business, including with respect to the efficiency and resiliency of our systems. For example, our AI-related efforts may give rise to risks related to harmful content, accuracy, bias, discrimination, intellectual property infringement or misappropriation, defamation, data privacy, and cybersecurity, among others. In addition, the adoption of AI may subject us to new or enhanced governmental or regulatory scrutiny, new or amended laws, rules, directives, and regulations governing the use of AI, litigation, ethical concerns, negative consumer perceptions as to automation and AI, or other complications that could adversely affect our business, reputation, or financial results. We may not be able to recover our investments in AI technology through our regulatory proceedings, and our use of, or our third parties' use of, AI may subject us to legal liability. Similarly, as AI continues to evolve, we may not be able to adopt and implement AI as quickly as our customers or communities desire or regulators may require, which could also adversely affect us. AI is a relatively new and rapidly evolving technology, and we are unable to predict all of the risks that may result from the adoption of our AI initiatives.

General and Other Risks

Our revenues and results of operations are seasonal.

Houston Electric's, Indiana Electric's and Natural Gas' revenues and results of operations are subject to seasonality, weather conditions and other changes in electricity and natural gas usage, as applicable. Houston Electric's revenues are generally higher during the warmer months. As in certain past years, unusually mild weather in the warmer months could diminish Houston Electric's results of operations and harm its financial condition. Conversely, as in certain past years, extreme warm weather conditions could increase Houston Electric's results of operations in a manner that would not likely be annually recurring. A significant portion of Indiana Electric's sales are for space heating and cooling. Consequently, as in certain past years, Indiana Electric's results of operations may be adversely affected by warmer-than-normal heating season weather or colder-than-normal cooling season weather, while, as has occurred in certain past years, more extreme seasonal weather conditions could increase Indiana Electric's results of operations in a manner that would not likely be annually recurring. Natural Gas' revenues are customarily higher during the winter months. As in certain past years, unusually mild weather in the winter months could diminish Natural Gas' results of operations and harm its financial condition. Conversely, as occurred in certain past years, extreme cold weather conditions could increase its results of operations in a manner that would not likely be annually recurring. For additional risks related to the February 2021 Winter Storm Event, see Note 7 to the consolidated financial statements for further information.

Climate change and other weather and natural disaster impacts could adversely impact financial results from our businesses and our results of operations.

A changing climate creates uncertainty and could result in broad changes, both physical and financial in nature, to our service territories and our business. If climate changes occur that result in warmer temperatures than normal in our service territories, financial results from our businesses could be adversely impacted. For example, where natural gas is used to heat homes and businesses, warmer weather might result in less natural gas being used, adversely affecting us.

Another possible result of climate change is more frequent and more severe weather events. Weather-related incidents have become more prevalent, unpredictable and severe as a result of climate change or other factors. Severe weather events impact our service territories, primarily when hurricanes, tornadoes, floods, severe winter weather conditions, including ice storms, wildfires, thunderstorms, high winds, hail, derecho events, microbursts, or extreme temperatures (high heating/cooling days) occur, which can impact our operations and our ability to serve our customers, including resulting in large-scale and/or prolonged outages. To the extent the frequency and severity of extreme weather events increases, our costs of providing service may increase, including the costs and availability of procuring insurance related to such impacts, and those costs may not be recoverable. Further, events of extreme weather could make it unsafe or hinder the effectiveness of our employees to fix, maintain and restore power to affected areas and could harm our reputation. Since certain of our facilities are located along or near the Texas Gulf Coast, increased or more severe hurricanes, tornadoes or derecho events could increase our costs to repair damaged facilities and restore service to our customers. Our Electric and Natural Gas operations in our service territories have both been impacted by severe weather events, including the February 2021 Winter Storm Event, the May 2024 Storm Event and Hurricane Beryl, and could experience similar events in the future, which could have an adverse impact on our financial condition, results of operations and cash flows.

Wildfires also have the potential to negatively affect communities our service territories and the surrounding areas, as well as our electric and natural gas infrastructure, including Houston Electric's and Indiana Electric's vast network of electric transmission and distribution lines and facilities and CERC's natural gas distribution systems. The possibility of wildfires and the risk of damage to our network, facilities and systems resulting therefrom may be exacerbated by severe weather events and the effects of climate change. The continued expansion of the wildland-urban interface has also increased wildfire risk to communities in our service territories. While we proactively take steps to mitigate wildfire risk in the areas of our electrical and natural gas assets, wildfire risk is always present. We could be held liable for damages incurred as a result of wildfires or incur reputational harm if it was determined that they were caused by or enhanced due to any fault of CenterPoint Energy. In addition, while we maintain wildfire insurance, our insurance may not be sufficient to cover all losses we may incur as a result of wildfires. Wildfires could also lead to significant financial distress and further increased costs for wildfire insurance or lack of availability thereof. Insufficient wildfire insurance coverage, increased wildfire insurance costs and a lack of wildfire insurance availability could adversely impact our financial condition, results of operations and cash flows. Furthermore, any

damage caused to our assets, loss of service to our customers or liability imposed as a result of wildfires could negatively impact our financial condition, results of operations and cash flows.

In the long term, climate change could also cause shifts in population, including customers moving away from our service territories. When we cannot deliver electricity or natural gas to customers or our customers cannot receive our services, our financial results are impacted by lost revenues, and we generally must seek approval from regulators to recover restoration costs. To the extent we are unable to recover those costs or recover in a timely manner, or if recovery of such costs results in higher rates and reduced demand for our services, our future financial results may be adversely impacted. Similarly, public and private efforts to address climate change, such as by legislation, regulation, actions by private interest groups, and litigation, could impact our ability to continue operating our businesses as we do today, significant aspects of which rely on fossil fuels. These initiatives could have a significant impact on us and our operations as well as on our third-party suppliers, vendors and partners, which could impact us by among other things, causing permitting and construction delays, project cancellations or increased project costs passed on to us. For further information on these initiatives, see "— We are subject to operational…" Finally, we may be subject to climate change litigation, which could result in substantial fines, penalties or damages and restrictions on our operations. The utility industry has already faced such litigation, challenging its marketing and use of fossil fuels and attributing climate change to emissions resulting from the use of fossil fuels. For more information, see "— CenterPoint Energy is subject to operational and financial risks..."

We are exposed to risks related to changes in demand and energy consumption that could adversely impact financial results from our businesses and our results of operations.

Our businesses are affected by reduction in energy consumption due to factors including economic, climate and market conditions in our service territories, energy efficiency initiatives, use of alternative technologies and changes in our customers' perceptions regarding natural gas usage as a result of incidents of other utilities involving natural gas pipelines, which could impact our ability to grow our customer base and our rate of growth. Growth in customer accounts and growth of customer usage each directly influence demand for electricity and natural gas and the need for additional delivery facilities. Customer growth and customer usage are affected by a number of factors outside our control, such as mandated energy efficiency measures, bans on or further regulation of natural gas-fired appliances, demand-side management goals, distributed generation resources and economic and demographic conditions, including population changes, job and income growth, housing starts, new business formation and the overall level of economic activity. Declines in demand for electricity and natural gas in our service territories due to pipeline incidents of other utilities, increased electricity and natural gas prices as experienced during the February 2021 Winter Storm Event and during periods of persisting high inflation or economic downturns, among other factors, could reduce overall usage and lessen cash flows, especially as industrial customers reduce production and, therefore, consumption of electricity and natural gas. Although Houston Electric's and Indiana Electric's transmission and distribution businesses are subject to regulated allowable rates of return and recovery of certain costs under periodic adjustment clauses, overall declines in electricity delivered and used as a result of economic downturn or recession could reduce revenues and cash flows, thereby diminishing results of operations. A reduction in the rate of economic, employment and/or population growth could result in lower growth and reduced demand for and usage of electricity and natural gas in such service territories. Additionally, certain laws in our service territories allow municipalities to create, own, and operate utilities. If one or more municipalities in our service territories create new or supplemental utilities, or impair the franchises under which we serve customers in the applicable municipalities, it could result in lower growth and reduced demand for and usage of electricity and natural gas in such service territories. Some or all of these factors could result in a lack of growth or decline in customer demand for electricity or natural gas or number of customers and may result in our failure to fully realize anticipated benefits from significant capital investments and expenditures, which could have an adverse effect on our financial condition, results of operations and cash flows.

Additionally, our operations are affected by new customers and load growth. For example, the expansion of data centers (associated with, among other things, increasing demand for artificial intelligence), energy export facilities, including hydrogen facilities, electrification of industrial processes and transport and logistics, among others, could lead to an unprecedented increase in demand for electric power in our service territories. As we evaluate business opportunities presented by such development in our service territories, we are subject to potential challenges including accurately predicting future power needs due to rapidly changing technology and market dynamics, managing the potential power demand, generation sources, and transmission capabilities to meet potential load growth, financing the capital investment needed to build and maintain the necessary infrastructure to support such development, managing the possible environmental impact of the potential increased power demand, achieving our net zero and GHG emissions reduction goals and evaluating and complying with evolving regulations related to such development. Our efforts to predict and address these challenges could have a material impact on us, including if we fail to fully realize anticipated benefits from significant capital investments and expenditures made to address such development, which could have an adverse effect on our financial condition, results of operations and cash flows.

Aging infrastructure may lead to increased costs and disruptions in operations that could negatively impact our financial results.

We have risks associated with aging infrastructure assets, including the failure of equipment or processes and potential breakdowns due to such aging. The age of certain of our assets may result in a need for replacement or higher level of maintenance costs because of our risk based federal and state compliant integrity management programs. As part of our long-term capital plan, GHRI and the SRP, we continue to make upgrades to our aging infrastructure assets to enhance the reliability of our infrastructure. Failure to achieve timely and full recovery of expenses associated with our aging infrastructure could adversely impact revenues and could result in increased capital expenditures or expenses. In addition, the nature of information available on aging infrastructure assets may make inspections, maintenance, upgrading and replacement of the assets particularly challenging. Also, our ability to successfully maintain or replace our aging infrastructure may be delayed or be at a greater cost than anticipated due to supply chain disruptions. Further, with respect to Natural Gas' operations, if certain pipeline replacements (for example, cast-iron or bare steel pipe) are not completed timely or successfully, government agencies and private parties might allege the uncompleted replacements caused events such as fires, explosions or leaks. Although we maintain insurance for certain of our facilities, our insurance coverage may not be sufficient in the event a catastrophic loss is alleged to have been caused by a failure to timely complete equipment replacements. Insufficient insurance coverage and increased insurance costs could adversely impact our financial condition, results of operations and cash flows. Finally, aging infrastructure may complicate our utility operations ability to address climate change concerns and efforts to enhance resiliency and reliability. See "— Disruptions to the global supply..."

Our financial condition, results of operations and cash flows may be adversely affected if we are unable to successfully operate our facilities or perform certain corporate functions.

Our performance depends on the successful operation of our facilities. Operating these facilities involves many risks inherent in the generation, transmission and distribution of electricity and in the delivery of natural gas that could result in substantial losses or other damages. From time to time, we have and may in the future experience various risks associated with the operations of our facilities, including, but not limited to, the following:

- operator error or failure of equipment or processes, including natural gas ignition events or associated incidents, pipeline over-pressure events or ruptures, or failure to follow appropriate safety protocols for, among others, the transmission and distribution of electricity and in the delivery of natural gas, including operations of our peak shaving facilities;
- the handling of hazardous equipment or materials that could result in serious personal injury, loss of life and environmental and property damage;
- operating limitations that may be imposed by environmental or other regulatory requirements;
- labor disputes;
- information technology or financial and billing system failures, including those due to the implementation and integration of new technology, that impair our information technology infrastructure, reporting systems or disrupt normal business operations;
- compliance mandates that result in penalties from our regulators;
- failure to obtain in a timely manner and at reasonable prices the necessary fuel, such as coal and natural gas, building materials or other items needed to operate our facilities;
- information technology failure, including failure of AI technology, that affects our ability to access customer information or causes us to lose confidential or proprietary data that adversely affects our reputation or exposes us to legal claims; and
- catastrophic events such as fires, earthquakes, explosions, leaks, floods, droughts, hurricanes, tornados, derecho events, ice storms, terrorism, wildfires, pandemic health events, geopolitical conflict or other similar occurrences, including any environmental impacts related thereto, which catastrophic events may require participation in mutual assistance efforts by us or other utilities to assist in power restoration efforts, and for which our emergency preparedness plans may not be adequate or we may not respond effectively, which could result in public or employee harm.

Such events may result in a decrease or elimination of revenue from our facilities, an increase in the cost of operating our facilities, delays in cash collections, harm to our reputation, less favorable legislative and regulatory outcomes or increased regulatory oversight, any of which could have an adverse effect on our business, financial condition, results of operations and

cash flows. Such events have and may in the future result in the imposition of regulatory or environmental fines and increased litigation.

Our businesses will continue to have to adapt to technological change and may not be successful or may have to incur significant expenditures to adapt to technological change.

We operate businesses that require sophisticated data collection, processing systems, software and other technology. Some of the technologies supporting the industries we serve are changing rapidly and increasing in complexity. New technologies will emerge or grow that may be superior to, or may not be compatible with, some of our existing technologies, and may require us to make significant investments and expenditures so that we can continue to provide cost-effective and reliable methods for energy production and delivery. Among such technological advances are distributed generation resources (e.g., private solar, microturbines, fuel cells), energy storage devices and more energy-efficient buildings and products designed to reduce energy consumption, emissions attributable to our operations and waste. As these technologies become a more cost-competitive option over time, whether through cost effectiveness or government incentives and subsidies, such as under the IRA, certain customers may choose to meet their own energy needs and subsequently decrease usage of our systems and services, including Indiana Electric's generating facilities becoming less competitive and economical. Further, certain regulatory and legislative bodies have introduced or are considering requirements and incentives to reduce energy consumption by certain dates. Just as high inflation and rising interest rates incentivize our customers to consume less energy, technological advances driven by federal laws mandating new levels of energy efficiency in end-use electric and natural gas devices or other improvements in or applications of technology could lead to declines in per capita energy consumption.

Our future success will depend, in part, on our ability to anticipate and adapt to these technological changes in a cost-effective manner, to offer, on a timely basis, reliable services that meet customer demands and evolving industry standards, and to recover all, or a significant portion of, any unrecovered investment in obsolete assets. For example, an expansion of data centers, energy export facilities, including hydrogen facilities, electrification of industrial processes and transport and logistics, among others, could generate a significant increase in demand for electric power in CenterPoint Energy's service territories, which may require us to rapidly adopt new technologies and make significant transmission and distribution investments, including advanced grid infrastructure, which increases exposure to overall grid instability and technology obsolescence. If we fail to adapt successfully to any technological change or obsolescence, fail to obtain access to important technologies or incur significant expenditures in adapting to technological change, or if implemented technology does not operate as anticipated, our businesses, financial condition, results of operations and cash flows could be adversely affected.

Our insurance coverage may not be sufficient. Insufficient insurance coverage and increased insurance costs could adversely impact our financial condition, results of operations and cash flows.

We currently have insurance in place, such as general liability and property insurance, to cover certain of our facilities in amounts that we consider appropriate. Such policies are subject to certain limits and deductibles and do not include business interruption coverage. Insurance coverage premiums continue to increase, and insurance coverage may not be available in the future at current costs or on commercially reasonable terms, and the insurance proceeds received for any loss of, or any damage to, any of our facilities may not be sufficient to fully cover or restore the loss or damage without negative impact on our financial condition, results of operations and cash flows. Costs, damages and other liabilities related to recent events and incidents that affected other utilities, such as wildfires, winter storms and explosions, among other things, have exceeded or could exceed such utilities' insurance coverage. Further, as a result of these recent events and incidents, the marketplace for insurance coverage to utility companies may be unavailable or limited in capacity or any such available coverage may be deemed by us to be cost prohibitive under current conditions. Insurance premiums for any such coverage, if available, may not be eligible for recovery, whether in full or in part, by us through the rates charged by our utility businesses.

In common with other companies in its line of business that serve coastal regions, Houston Electric does not have insurance covering its transmission and distribution system, other than substations, because Houston Electric believes it to be cost prohibitive and insurance capacity to be limited. Historically, Houston Electric has been able to recover the costs incurred in restoring its transmission and distribution properties following hurricanes or other disasters through issuance of storm restoration bonds or a change in its regulated rates or otherwise. In the future, any such recovery may not be granted. Therefore, Houston Electric may not be able to restore any loss of, or damage to, any of its transmission and distribution properties without negative impact on its financial condition, results of operations and cash flows.

Global or regional health pandemics, epidemics or similar public health threats could negatively impact our business, outlook, financial condition, results of operations and liquidity.

Current and future health pandemics, epidemics and similar public health threats and the measures implemented to contain their spread, such as travel bans and restrictions, quarantines and vaccination mandates, have had and may in the future have widespread impacts on the global economy, our employees, customers, and third-party business partners. The severity, magnitude and duration of future health threats is uncertain and hard to predict. Any future health threat could impact our business in numerous ways, including, but not limited to, those outlined below:

- reduced demand from our commercial and industrial customers and shifts in demand for our services;
- delayed service to customers because of shutdowns or illness and travel restrictions among our employees;
- negative impacts to the financial condition of our customers and REPs and their ability to pay for our services, and our ability to disconnect service for non-payment may be limited, and state regulators may impose bill deferral programs;
- potential limits or significant or entire curtailments of the ability of public utility commissions to approve or authorize applications and other requests we may make with respect to our businesses, including delaying rate making proceedings;
- increased risk to our cybersecurity program as a result of an increase in cyberattacks during the pandemic and increased remote working arrangements (for further information, see "— Risk Factors Affecting Safety and Security Risks");
- increased rates of inflation and delays in our supply chain and our ability to complete maintenance, repairs, and capital programs, which could result in disruption, increased costs and our inability to execute on or require us to make modifications to our capital plan; and
- accelerated employee turnover as a result of concerns regarding restrictions and guidelines, including mask mandates and quarantine mandates, and increased acceptability of alternative work arrangements.

Like many companies, we experienced the above and other impacts during the COVID-19 pandemic. These and other impacts of global or regional health pandemics, epidemics or similar public health threats could also have the effect of heightening many of the other risks described in this section and the other reports we file from time to time with the SEC. We might not be able to predict or respond to all impacts on a timely basis to prevent near- or long-term adverse impacts to our operations, financial condition and liquidity. The ultimate impact of public health threats on our business depends on factors beyond our knowledge or control, including the duration and severity of the outbreak as well as third-party actions taken to contain the spread and mitigate the public health effects. Any of these factors could have a negative impact on our business, outlook, financial condition and results of operations, which impact could be material.

Our success depends upon our ability to attract, effectively transition, motivate and retain key employees and identify and develop talent to succeed senior management.

We depend on senior executive officers and other key personnel. Our success depends on our ability to attract, effectively transition and retain key personnel. Further tightening of the labor market and increasing wages to attract and retain key personnel may adversely affect our ability to attract and retain key personnel. The inability to recruit and retain or effectively transition key personnel or the unexpected loss of key personnel may adversely affect our operations. In addition, because of the reliance on our management team, our future success depends in part on our ability to identify, motivate and develop talent to succeed senior management. The retention of key personnel and appropriate senior management succession planning will continue to be critically important to the successful implementation of our strategies.

Failure to attract and retain an appropriately qualified workforce and maintain good labor relations could adversely impact the operations of our facilities and our results of operations.

Our businesses are dependent on recruiting, retaining and motivating employees. Like many companies in the utilities industry and other industries, we have experienced higher than normal turnover of employees as a result of a number of factors, including a tightening labor market, increasing remote working opportunities, employees shifting industries, individuals deciding not to work and a maturing workforce. Of our employee population, not including employees of Energy Systems Group prior to its divestiture on June 30, 2023 or temporary employees, 18.2%, 18.7%, and 19.3% were retirement eligible as of December 31, 2024, 2023, and 2022, respectively. Certain circumstances, such as an aging workforce without appropriate replacements, a mismatch of existing skillsets to future needs, increased turnover or the unavailability of contract resources, may lead to operating challenges such as a lack of resources, loss of knowledge or a lengthy time period associated with skill development. Our costs, including costs to replace employees, productivity costs and safety costs, may rise. Failure to hire and adequately train replacement employees, including the transfer of significant internal historical knowledge and expertise to the new employees, or the future availability and cost of contract labor may adversely affect the ability to manage and operate our

businesses, particularly the specialized skills and knowledge required to construct and operate generation facilities, a technology-enabled power grid and transmission and distribution infrastructure, among other facilities. If we are unable to successfully attract and retain an appropriately qualified workforce, our ability to execute on our 10-year capital plan and our results of operations could be negatively affected.

Furthermore, the operations of our facilities depend on good labor relations with our employees, and several of our businesses have in place collective bargaining agreements with different labor unions, comprising approximately 39% of our workforce. We have several separate bargaining units, each with a unique collective bargaining agreement described further in Note 8(j) to the consolidated financial statements, which information is incorporated herein by reference. The collective bargaining agreements with Gas Workers Union Local 340, IBEW Local 949 and OPEIU Local 12 related to CERC employees in Minnesota, as well as with IBEW Local 702 related to SIGECO employees, are scheduled to expire in April 2025, December 2025, December 2025 and June 2025, respectively, and negotiations of these agreements are expected to be completed before the respective expirations. Any failure to reach an agreement on new labor contracts or to negotiate these labor contracts might result in strikes, boycotts or other labor disruptions. These potential labor disruptions could have an adverse effect on our businesses, results of operations and/or cash flows. Labor disruptions, strikes or significant negotiated wage and benefit increases, whether due to union activities, employee turnover or otherwise, could have an adverse effect on our businesses, results of operations and cash flows.

Item 1B. ***Unresolved Staff Comments***

None.

Item 1C. ***Cybersecurity***

Our processes for assessing, identifying, and managing material risks from cybersecurity threats are part of our overall enterprise risk management system and processes. Enterprise risks, including cybersecurity risks, and their associated mitigations are reviewed at least annually by senior management and the Board of Directors. Throughout the year, we regularly assess our cybersecurity program and continue to invest in hardening and maturing our cybersecurity measures as further described below.

Risk Management Strategy and Processes

We maintain a cybersecurity program to help us assess, identify, and manage cybersecurity risks to our systems and data, including to help us defend against and mitigate emerging and existing cybersecurity threats to our information technology and operational technology systems. Our strategies and processes for managing cybersecurity risks are informed by relevant industry frameworks and laws, regulations and standards applicable to us in the jurisdictions in which we do business, including those applicable to utilities that operate bulk electric systems or critical pipeline facilities. We maintain various policies, procedures, technologies and other controls to help prevent, detect, mitigate and manage cybersecurity threats and incidents. We also use third-party consultants and service providers to support our risk management efforts, such as services for cybersecurity intelligence, monitoring, testing and assessments.

Key aspects of our risk management processes include:

- Threat Monitoring. We receive information on emerging cybersecurity threats and vulnerabilities from different sources, including vendors, cybersecurity organizations and U.S. government agencies, to help support our ability to detect and defend against threats to the security of our information technology and operational technology systems. We maintain several cybersecurity monitoring tools and services to help us detect unauthorized activities involving our systems and potential cybersecurity threats and vulnerabilities to our systems.

- Incident Response. We maintain a Cybersecurity Operations Center that is dedicated to monitoring for cybersecurity threats to our systems and responding to potential cybersecurity incidents. We also maintain cybersecurity incident response plans that establish a cross-functional incident response team and processes to guide our response to cybersecurity incidents, including processes for reporting and escalating cybersecurity incidents to senior management and the Audit Committee or the Board, as appropriate. We conduct tabletop exercises annually to test our incident response processes.

- Assessments, Testing and Audits. We conduct different types of security assessments, testing and audits to help us proactively identify and mitigate potential cybersecurity threats and vulnerabilities to our information technology and

operational technology systems. For example, we conduct security-related risk assessments on proposed software, hardware, and third-party technology solutions used by CenterPoint Energy prior to deployment in our network. We also undergo periodic vulnerability assessments, penetration tests and cybersecurity reviews of our systems and security controls. We engage third parties to support certain of these assessments and tests and to provide guidance and support to our cybersecurity management team. Our internal audit team also conducts audits of certain CenterPoint Energy systems and data security controls.

- Third-Party Risk Management. We maintain a vendor risk management program, a component of which assesses the cybersecurity and data privacy practices of certain third-party service providers to help us assess and manage cybersecurity risks associated with third-party access to our systems and data. To help identify and mitigate third-party cybersecurity risks, we conduct vendor security reviews and privacy impact assessments when deemed appropriate based on the nature of the systems and data that will be accessed by the third-party. We also impose contractual obligations on certain of our service providers related to data privacy, confidentiality and security based on, among other factors, their extent of access to our data and systems and the nature and sensitivity of the data and systems to which they have access.

- Training and Awareness. We hold regular employee trainings on privacy, cybersecurity, AI and records and information management, conduct simulated phishing tests, and generally seek to promote awareness of cybersecurity risk through communication and education of our employee population.

As described in Item 1A "Risk Factors," our operations rely on the secure processing, storage, and transmission of confidential, sensitive, and other information within our computer systems and networks. Computer viruses, threat actors, employee or vendor incidents, and other external hazards could expose our information systems, and those of third parties who process our data, provide access to systems, or that have access to our systems, to security breaches, cybersecurity incidents or other disruptions, any of which could materially and adversely affect our business, reputation, results of operations and financial condition, and subject us to possible legal claims and liability. While we have experienced cybersecurity incidents in the past, as of the date of the filing of this Form 10-K, the Company has not identified any cybersecurity threats that have materially affected or are reasonably anticipated to have a material effect on us, including our business strategy, results of operations, or financial condition.

Governance

Board of Directors Oversight

Our Audit Committee, comprised of independent directors from our Board, oversees the Board's responsibilities relating to CenterPoint Energy's cybersecurity and data privacy programs, including cybersecurity risk management and cybersecurity disclosures required by applicable securities laws or regulations, as appropriate. As part of its risk oversight responsibilities, the Audit Committee receives quarterly reports from our Executive Vice President and General Counsel, Senior Vice President and Chief Information Security Officer (CISO) or other representatives from our cybersecurity or data privacy groups and periodic reports from our third-party consultants. These reports include updates on certain cybersecurity or data privacy matters, including, among other items, CenterPoint Energy's progress in maturing its cybersecurity program, results of significant cybersecurity assessments and testing, the cybersecurity landscape and emerging threats, status of ongoing initiatives and strategies, incident reports and learnings from any cybersecurity events, compliance with regulatory requirements and industry standards, data privacy matters, and the cybersecurity budget.

Risk Management Personnel

CenterPoint Energy's Executive Vice President and General Counsel is responsible for overseeing our cybersecurity and data privacy programs. CenterPoint Energy's CISO is responsible for the day-to-day management of our cybersecurity program and reports directly to the Executive Vice President and General Counsel. CenterPoint Energy's Senior Vice President, Deputy General Counsel, and Chief Ethics & Compliance Officer (CECO) is responsible for day-to-day management of our data privacy program and also reports directly to the Executive Vice President and General Counsel. Our cybersecurity and data privacy teams, which report directly to our CISO and CECO, respectively, are tasked with implementing our programs in support of cybersecurity and data privacy risk management. We also have management-level teams and committees, which include and/or collaborate with our CISO and CECO, that support, among other things, our processes to assess and manage cybersecurity risk. These teams and committees provide summary reports on their activities and initiatives to appropriate senior executives, including the Executive Vice President and General Counsel and the Audit Committee or the Board, as appropriate.

CenterPoint Energy's CISO joined the Company in September 2024 and has over two decades of experience serving in multiple global leadership roles in cybersecurity, as well as technology and industrial systems at a Fortune 500 global industrial company, for which he was responsible for, among other things, building and maintaining enterprise programs relating to cybersecurity and managing cybersecurity risk. Our Executive Vice President and General Counsel has significant risk management, governance and litigation experience, which we believe are important leadership skills to help incorporate risk management, legal, disclosure and governance perspectives into the design of our cybersecurity program and in evaluating and responding to potential cybersecurity incidents.

Item 2. *Properties*

The following discussion is based on the Registrants' businesses as of December 31, 2024.

Character of Ownership

We lease or own our principal properties in fee, including our corporate office space and various real property. Most of our electric lines and natural gas mains are located, pursuant to easements and other rights, on public roads or on land owned by others.

Electric (CenterPoint Energy and Houston Electric)

Properties

All of Houston Electric's properties are located in Texas. Its properties consist primarily of high-voltage electric transmission lines and poles, distribution lines, substations, service centers, service wires, telecommunications networks and meters. Most of Houston Electric's transmission and distribution lines have been constructed over lands of others pursuant to easements or along public highways and streets under franchise agreements and as permitted by law.

All real and tangible properties of Houston Electric, subject to certain exclusions, are currently subject to the lien of the M&DOT and the lien of the General Mortgage, which is junior to the lien of the M&DOT.

No first mortgage bonds are outstanding under the M&DOT and Houston Electric is contractually obligated to not issue any additional first mortgage bonds under the M&DOT. Houston Electric is undertaking actions to release the lien of the M&DOT and terminate the M&DOT. For information related to debt outstanding under the General Mortgage, see Note 12 to the consolidated financial statements.

Indiana Electric's properties are primarily located in Indiana. They consist of transmission lines in Indiana and Kentucky, distribution lines, substations, service centers, coal-fired generating facilities, gas-fired turbine peaking units, a landfill gas electric generation project and solar generation facilities.

All real and tangible properties of Indiana Electric, subject to certain exclusions, are currently subject to the lien of the Amended and Restated Mortgage Indenture dated as of January 1, 2023, between SIGECO (Indiana Electric) and Deutsche Bank Trust Company Americas (formerly known as Bankers Trust Company), as Trustee.

Electric Lines - Transmission and Distribution. As of December 31, 2024, Houston Electric and Indiana Electric owned and operated the following electric transmission and distribution lines:

	Houston Electric		Indiana Electric	
Description	**Overhead Lines**	**Underground Lines**	**Indiana**	**Kentucky (1)**
Transmission lines:		**(in Circuit Miles)**		
69 kV	109	2	568	—
138 kV	2,347	24	422	9
345 kV	1,445	—	49	15
Total	3,901	26	1,039	24
Distribution lines	29,327	27,000	7,318	—

(1) These assets interconnect with Louisville Gas and Electric Company's transmission system at Cloverport, Kentucky and with Big Rivers Electric Cooperative at Sebree, Kentucky.

Generating Capacity. As of December 31, 2024, Indiana Electric had 577 MW of installed generating capacity, as set forth in the following table:

Generation Source	Unit No.	Location	Date in Service	Capacity (MW)
Coal				
F.B. Culley	2	Warrick County, Indiana	1966	90
F.B. Culley	3	Warrick County, Indiana	1973	270
Total Coal Capacity				360
Gas				
Brown (1)	3	Posey County, Indiana	1991	80
Brown	4	Posey County, Indiana	2002	80
Renewable Landfill Gas		Pike County, Indiana	2009	3
Total Gas Capacity				163
Solar				
Oak Hill		Evansville, Indiana	2018	2
Volkman		Evansville, Indiana	2018	2
Troy		Spencer County, Indiana	2021	50
Total Solar Capacity				54
Total Generating Capacity (2)				577

(1) Brown Unit 3 is also equipped to burn oil.
(2) Excludes 1.5% participation in OVEC. See Item 1. Business for more details.

Natural Gas Combustion Turbines. In 2022, Indiana Electric received approval from the IURC for a CPCN seeking approval to construct two natural gas combustion turbines to replace portions of its existing coal-fired generation fleet. The turbines are targeted to be operational by mid-year 2025. For further information, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Regulatory Matters" in Item 7 of Part II of this report, which discussion is incorporated herein by reference.

Solar. Indiana Electric entered into an amended and restated BTA to build a 191 MW solar array in Posey County, Indiana, , and a BTA to acquire a 130 MW solar array in Pike County, Indiana through a special purpose entity for a capped purchase price; however on March 15, 2024, Indiana Electric provided notice to the IURC that it was exercising its right to terminate this BTA. For further information about Indiana Electric's BTA's, see "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Regulatory Matters" in Item 7 of Part II of this report, which discussion is incorporated herein by reference.

Temporary Generation. As allowed by a law enacted by the Texas legislature after the February 2021 Winter Storm Event and amended in 2023, Houston Electric is leasing TEEEF that can aid in restoring power to customers during certain significant power outages that are impacting its distribution system. On December 19, 2024, Houston Electric announced a proposal to release certain of Houston Electric's TEEEF to the San Antonio area prior to the summer of 2025 for a period of up to two years, during which Houston Electric would not receive revenue or profit from ERCOT and would not charge Houston-area customers for these TEEEF units. As of December 31, 2024, Houston Electric leased 505 MW of TEEEF. For more information, see Note 7 and Note 19 to the consolidated financial statements.

Substations. A substation is a facility that transforms electricity from a higher voltage to a lower voltage or vice versa. Generally, this facility is the interface between the transmission system and the distribution grid. The following table presents certain information related to CenterPoint Energy's substations as of December 31, 2024:

	Number of Substations	Transformer Capacity (in Mva)
Houston Electric	243	73,667
Indiana Electric	109	6,992
Total CenterPoint Energy	352	80,659

Service Centers. Service centers consist of office buildings, warehouses and repair facilities that are used in the business of transmitting and distributing electricity. The following table presents certain information related to CenterPoint Energy's service centers as of December 31, 2024:

	Number of Service Centers	Acres of Land
Houston Electric	13	362
Indiana Electric	6	70
Total CenterPoint Energy	19	432

Natural Gas (CenterPoint Energy and CERC)

CenterPoint Energy's and CERC's Natural Gas use various third-party storage services or owned natural gas storage facilities to meet peak-day requirements and to manage the daily changes in demand due to changes in weather. CenterPoint Energy's and CERC's Natural Gas may also supplement contracted supplies and storage from time to time with stored LNG and propane-air plant production.

As of December 31, 2024, CenterPoint Energy's and CERC's Natural Gas owned and operated the following natural gas facilities:

	No. of Assets	Storage Capacity (Bcf)	Working Capacity (Bcf)	Maximum Daily Withdrawal Rate (MMcf)
CenterPoint Energy				
Underground Natural Gas Storage Facility	8	43	14	305
CERC				
Underground Natural Gas Storage Facility	5	32	9	205

			On-site Storage Capacity	
	No. of Assets	Daily Production Rate (Dth)	Millions of Gallons	Dth
CenterPoint Energy and CERC				
Propane Air-Gas Manufacturing Plant	15	247,000	14	1,228,000
LNG Plant Facility	1	72,000	12	1,010,000

The table below reflects CenterPoint Energy's and CERC's Natural Gas contracted upstream storage services as of December 31, 2024:

	Storage Capacity (Bcf)	Maximum Peak Daily Delivery (MMcf)
Upstream Storage Service	89	2,311

The table below reflects the approximate total linear miles of CenterPoint Energy's and CERC's Natural Gas distribution and transmission mains owned as of December 31, 2024:

	CenterPoint Energy	CERC
All Locations	85,000	82,000
Indiana and Ohio	22,000	19,000

CenterPoint Energy's and CERC's Natural Gas owned mains varying in size from one-half inch to 24 inches in diameter. CenterPoint Energy's and CERC's Natural Gas Indiana and Ohio mains are located in Indiana and Ohio except for, in the case of CenterPoint Energy, pipeline facilities extending from points in northern Kentucky to points in southern Indiana so that gas may be transported to Indiana and sold or transported to customers in Indiana. Generally, in each of the cities, towns and rural areas served by CenterPoint Energy's and CERC's Natural Gas, they own the underground gas mains and service lines, metering and regulating equipment located on customers' premises and the district regulating equipment necessary for pressure

maintenance. With a few exceptions, the measuring stations at which CenterPoint Energy's and CERC's Natural Gas receive gas are owned, operated and maintained by others, and their distribution facilities begin at the outlet of the measuring equipment. These facilities, including odorizing equipment, are usually located on land owned by suppliers.

As of December 31, 2024, CenterPoint Energy and CERC, through CEIP, owned and operated over 219 miles of intrastate pipeline in Louisiana and Texas. On February 19, 2024, CenterPoint Energy, through its subsidiary CERC Corp., entered into the LAMS Asset Purchase Agreement to sell its Louisiana and Mississippi natural gas LDC businesses, which include the intrastate pipelines owned by CEIP in Louisiana. The transaction is expected to close in the first quarter of 2025. For further information, see Note 4 to the consolidated financial statements.

Item 3. ***Legal Proceedings***

For a discussion of material legal and regulatory proceedings, including environmental legal proceedings that involve a governmental authority as a party and that the Registrants reasonably believe would result in $1,000,000 or more of monetary sanctions, exclusive of interest and costs, under federal, state and local laws that have been enacted or adopted regulating the discharge of materials into the environment or primarily for the purpose of protecting the environment, affecting the Registrants, read "Business — Regulation" and "Business — Environmental Matters" in Item 1 of this report, "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources — Regulatory Matters" in Item 7 of Part II of this report and Note 14(d) to the consolidated financial statements, which information is incorporated herein by reference.

Item 4. ***Mine Safety Disclosures***

Not applicable.

PART II

This combined Form 10-K is filed separately by three registrants: CenterPoint Energy, Inc., CenterPoint Energy Houston Electric, LLC and CenterPoint Energy Resources Corp.

Item 5. ***Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities***

CenterPoint Energy

As of February 10, 2025, CenterPoint Energy's common stock was held by approximately 21,495 shareholders of record. CenterPoint Energy's common stock is listed on the NYSE and NYSE Chicago and is traded under the symbol "CNP."

The amount of future cash dividends will be subject to determination based upon CenterPoint Energy's financial condition and results of operations, future business prospects, any applicable contractual restrictions and other factors that CenterPoint Energy's Board of Directors considers relevant and will be declared at the discretion of CenterPoint Energy's Board of Directors. For further information on CenterPoint Energy's dividends, see Note 11 to the consolidated financial statements.

Repurchases of Equity Securities

During the quarter ended December 31, 2024, none of CenterPoint Energy's equity securities registered pursuant to Section 12 of the Securities Exchange Act of 1934, as amended, were purchased by or on behalf of CenterPoint Energy or any "affiliated purchasers," as defined in Rule 10b-18(a)(3) under the Securities Exchange Act of 1934, as amended.

Houston Electric

As of February 10, 2025, all of Houston Electric's 1,000 outstanding common shares were held by Utility Holding, LLC, a wholly-owned subsidiary of CenterPoint Energy.

CERC

As of February 10, 2025, all of CERC Corp.'s 1,000 outstanding shares of common stock were held by Utility Holding, LLC, a wholly-owned subsidiary of CenterPoint Energy.

Item 6. ***[Reserved]***

Item 7. ***Management's Discussion and Analysis of Financial Condition and Results of Operations***

The following combined discussion and analysis should be read in combination with the consolidated financial statements included in Item 8 herein. The discussion of CenterPoint Energy's consolidated financial information includes the results of CenterPoint Energy Houston Electric, LLC and CenterPoint Energy Resources Corp., which, along with CenterPoint Energy, Inc., are collectively referred to as the Registrants. Where appropriate, information relating to a specific registrant has been segregated and labeled as such. Unless the context indicates otherwise, specific references to Houston Electric and CERC also pertain to CenterPoint Energy. In this combined Form 10-K, the terms "our," "we" and "us" are used as abbreviated references to CenterPoint Energy, Inc. together with its consolidated subsidiaries, including Houston Electric and CERC, unless stated otherwise. No registrant makes any representations as to the information related solely to CenterPoint Energy, Inc. or the subsidiaries of CenterPoint Energy, Inc. other than itself.

OVERVIEW

Background

CenterPoint Energy is a public utility holding company. CenterPoint Energy's operating subsidiaries own and operate electric transmission, distribution and generation facilities and natural gas distribution systems. For a detailed description of CenterPoint Energy's operating subsidiaries, see Note 1 to the consolidated financial statements.

Houston Electric is an indirect, wholly-owned subsidiary of CenterPoint Energy, which provides electric transmission service to transmission service customers in the ERCOT region and distribution service to REPs serving the Texas Gulf Coast area that includes the city of Houston.

CERC Corp. is an indirect, wholly-owned subsidiary of CenterPoint Energy, which (i) directly owns and operates natural gas distribution systems in Louisiana, Minnesota, Mississippi and Texas, (ii) indirectly, through Indiana Gas and CEOH, owns and operates natural gas distribution systems in Indiana and Ohio, respectively, and (iii) owns and operates permanent pipeline connections through interconnects with various interstate and intrastate pipeline companies through CEIP.

On February 19, 2024, CenterPoint Energy, through its subsidiary CERC Corp., entered into the LAMS Asset Purchase Agreement to sell its Louisiana and Mississippi natural gas LDC businesses. The transaction is expected to close in the first quarter of 2025. For further information, see Note 4 to the consolidated financial statements.

Reportable Segments

We discuss our operating results on a consolidated basis and individually for each of our reportable segments. We are first and foremost an energy delivery company and it is our intention to remain focused on these regulated segments. The results of our business operations are significantly impacted by weather, customer growth, economic conditions, cost management, competition, rate proceedings before regulatory agencies and other actions of the various regulatory agencies to whose jurisdiction we are subject, among other factors.

Below is a summary of CenterPoint Energy's reportable segments as of December 31, 2024. For a detailed description of the assets included in each reporting segment, see Part I, Item 1. Business.

- The Electric reportable segment includes electric transmission and distribution services that are subject to rate regulation in Houston Electric's and Indiana Electric's service territories, as well as the impacts of generation-related stranded costs and other true-up balances recoverable by the regulated electric utility and energy delivery services to electric customers and electric generation assets to serve electric customers and optimize those assets in the wholesale power market in Indiana Electric's service territory.

- The Natural Gas reportable segment includes (i) intrastate natural gas sales to, and natural gas transportation and distribution for residential, commercial and industrial customers in Indiana, Louisiana, Minnesota, Mississippi, Ohio and Texas; (ii) permanent pipeline connections through interconnects with various interstate and intrastate pipeline companies through CEIP; and (iii) home appliance maintenance and repair services to customers in Minnesota and home repair protection plans to natural gas customers in Indiana, Mississippi, Ohio and Texas through a third party.

- The Corporate and Other reportable segment includes (i) energy performance contracting and sustainable infrastructure services by Energy Systems Group through June 30, 2023, the date of the sale of Energy Systems Group; (ii) corporate operations that support the business operations of CenterPoint Energy; and (iii) office buildings and other real estate used for business operations.

Houston Electric and CERC each consist of a single reportable segment.

EXECUTIVE SUMMARY

We expect our businesses to continue to be affected by the key factors and trends discussed below. Our expectations are based on assumptions made by us and information currently available to us. To the extent our underlying assumptions about, or interpretations of, available information prove to be incorrect, our actual results may vary materially from our expected results.

Factors Influencing Our Businesses and Industry Trends

We are an energy delivery company with electric transmission and distribution, power generation, and natural gas distribution operations that serve more than seven million metered customers across six jurisdictions. The majority of our revenues are generated from the transmission and delivery of electricity and the sale of natural gas by our subsidiaries.

We continue to execute on our strategic goals for our businesses which were set in 2021. These include our ten-year capital plan from 2021 through 2030, a focus on targeting controllable operations and maintenance savings for the benefit of our customers, prudent capital funding including divestitures of non-core assets, and net zero and GHG emissions reduction goals. Our focus continues to be on the growth of our regulated utility businesses including our electric and gas utility operations, which comprise over 95% of our earnings for the year ended December 31, 2024. See Note 16 to the consolidated financial statements for further details.

Pursuant to this business strategy and in light of the nature of our businesses, significant amounts of capital investment are reflected in our current 10-year capital plan, which has increased to nearly $47.5 billion through 2030. These investments include a focus on additional system resiliency, reliability, and grid modernization. These investments are not only intended to meet our customers' current needs, but are also in anticipation for further organic growth and load growth from increased electrification in our service territories. To fund these capital investments, we rely on internally-generated cash, borrowings under our credit facilities, proceeds from commercial paper, cash proceeds from strategic transactions (such as the divestitures of our Arkansas and Oklahoma LDC businesses in 2022, our Energy Systems Group divestiture in 2023 and the proposed sale of our Louisiana and Mississippi natural gas LDC businesses, which is expected to close in the first quarter of 2025), and issuances of equity and debt in the capital markets, including the issuance of non-recourse securitization bonds at Houston Electric related to costs incurred during the year ended December 31, 2024 due to the May 2024 Storm Events and Hurricane Beryl.

We strive to maintain investment grade ratings for our securities to access the capital markets on terms we consider reasonable. A reduction in our ratings generally would increase our borrowing costs for new issuances of debt, as well as borrowing costs under our existing revolving credit facilities, and may prevent us from accessing the commercial paper markets. Disruptions in the financial markets along with high or rising interest rates can also affect the availability of new capital on terms we consider attractive. In those circumstances, we may not be able to obtain certain types of external financing or may be required to accept terms less favorable than we would otherwise accept which, among other things, would negatively impact our ability to finance our capital plan. For that reason, we seek to maintain adequate liquidity for our businesses through existing credit facilities and prudent refinancing of existing debt.

The regulation of electric transmission, distribution and generation facilities as well as natural gas pipelines and related facilities by federal and state regulatory agencies affects our businesses. In accordance with applicable regulations, we are making, and will continue to make, significant capital investments in our service territories under our capital plan to help operate and maintain safer, more reliable and growing electric and natural gas systems. The current economic environment (e.g., sustained higher interest rates and higher relative levels of inflation in the United States) discussed further below could result in heightened regulatory scrutiny as these regulatory agencies seek to reduce the financial impact of utility bills on customers.

While greater than 80% of CenterPoint Energy's projected consolidated investments are expected to be recovered through interim capital recovery trackers or rate cases based on a forward test year, the balance is expected to be recovered through base rate cases. Indiana Electric filed a rate case during 2023, and Houston Electric and CERC's Ohio jurisdiction filed rate cases in 2024. The outcome of these base rate proceedings will determine, among other things, the ability to recover certain capital

investments within those jurisdictions. The outcome of these base rate proceedings is uncertain and may be impacted by the current economic environment. CERC's Texas and Minnesota gas jurisdictions filed rate cases in 2023, which were settled in 2024. For additional detail, see "—Liquidity and Capital Resources —Regulatory Matters" below.

To assess our financial performance, our management primarily monitors the recovery of costs and return on investments by the evaluation of net income and capital expenditures, among other things, from our regulated service territories within our reportable segments. Within these broader financial measures, we monitor margins, natural gas and fuel costs, interest expense, capital spend, working capital requirements, and operation and maintenance expense. In addition to these financial measures, we also monitor a number of variables that management considers important to gauge the performance of our reportable segments, including the number of customers, throughput, commodity prices, heating and cooling degree days, environmental impacts, safety factors, system reliability and customer satisfaction.

CenterPoint Energy and CERC have weather normalization or other rate mechanisms that largely mitigate the impact of weather on Natural Gas in Indiana, Louisiana, Mississippi, Minnesota and Ohio, as applicable. CenterPoint Energy's and CERC's Natural Gas in Texas and CenterPoint Energy's electric operations in Texas and Indiana do not have such mechanisms, although fixed customer charges are historically higher in Texas for Natural Gas compared to its other jurisdictions. As a result, fluctuations from normal weather may have a positive or negative effect on CenterPoint Energy's and CERC's Natural Gas' results in Texas and on CenterPoint Energy's electric operations' results in its Texas and Indiana service territories.

Each state has a unique economy and is driven by different industrial sectors. Our largest customers reflect the diversity in industries in the states across our footprint. For example, Houston Electric is largely concentrated in Houston, a diverse economy where a higher percentage of employment is tied to the energy sector relative to other regions of the country. Although the Houston area represents a large part of our customer base, we have a diverse customer base throughout the various states our utility businesses serve. In Minnesota, for instance, education and health services are the state's largest sectors. Indiana and Ohio are impacted by changes in the Midwest economy in general and changes in particular industries concentrated in the Midwest such as automotive, feed and grain processing. Some industries are driven by population growth like education and health care, while others may be influenced by strength in the national or international economy. Adverse economic conditions, coupled with concerns for protecting the environment and increased availability of alternate energy sources, may cause consumers to use less energy or avoid expansions of their facilities, including natural gas facilities, resulting in less demand for our services. Long-term national trends indicate residential customers have reduced their energy consumption, which could adversely affect our results. To the extent population growth is affected by lower energy prices and there is financial pressure on some of our customers who operate within the energy industry, there may be an impact on the growth rate of our customer base and overall demand. Management expects residential meter growth for Houston Electric to remain in line with long term trends at approximately 2%. Management additionally anticipates significant increased electric load growth demand in our Houston Electric service territory, including in relation to the expected expansion of data centers, energy export facilities, including hydrogen facilities, electrification of industrial processes and transport and logistics. Typical customer growth in the jurisdictions served by the Natural Gas reportable segment is approximately 1%. Management expects residential meter growth for CERC to remain in line with long term trends at approximately 1%.

Inflation and high interest rates and a recessionary environment could potentially adversely impact CenterPoint Energy's ability to execute on its 10-year capital plan. The inability to execute on our capital plan may result in lost future revenues for CenterPoint Energy. Additionally, these economic conditions may affect customers' ability to pay their utility bills which may preclude our ability to collect balances due from such customers.

Further, the global supply chain has experienced significant disruptions due to a multitude of factors, such as geopolitical and economic uncertainty, regulatory and political instability, import tariffs and trade agreements, labor shortages, resource availability, long lead times, manufacturer production limitations, delivery delays, inflation and severe weather events. These disruptions have adversely impacted the utility industry. Like many of our peers, we have experienced disruptions to our supply chain, as well as increased prices, and may continue to experience such disruptions in the future. For example, President Trump has expressed a desire to impose substantial new or increased tariffs, and in February 2025, imposed tariffs on several countries and certain imports into the United States. These tariffs, as well as any new legislation, tariffs, bans, potential retaliatory trade measures taken against the United States or related governmental action, could increase or cause volatility in the cost of and negatively impact our ability to procure materials, supplies (such as natural gas) or services necessary for our business and capital plan, lead to scarcity of resources and labor necessary for our business and capital plan, further extend lead time or otherwise negatively impact the supply chain and our ability to timely execute our capital plan. To the extent adverse economic conditions, including supply chain disruptions, affect our suppliers and customers as well as our ability to meet our capital plan and generation transition plan, including with respect to developing and constructing new generation facilities at the cost and scale and on the timelines that we anticipate, results from our energy delivery businesses may suffer. For more information, see Note 14 to the consolidated financial statements.

Further, in response to concerns for protecting the environment, we have strived to take a leading stance in the transition to safer and cleaner energy by being the first combined electric and natural gas utility with regulated generation assets to adopt net zero for its Scope 1 and certain Scope 2 emissions by 2035 goals. In addition, we set a Scope 3 emission reduction goal across our multi-state footprint by committing to help our residential and commercial customers reduce GHG emissions attributable to their end use of natural gas by 20% to 30% by 2035 from a 2021 baseline. Our capital plan supports these goals. For more information regarding CenterPoint Energy's net zero and GHG emissions reduction goals and the risks associated with them, see Part I, Item 1A. "Risk Factors — Risk Factors Affecting Regulatory, Environmental and Legal Risks — CenterPoint Energy is subject to operational and financial risks..."

Significant Events

May 2024 Storm Events and Hurricane Beryl. Houston Electric's service territory experienced sudden and destructive severe weather events in May 2024 that included hurricane-like winds and tornadoes. Subsequently, on July 8, 2024, Hurricane Beryl made landfall in Texas, bringing sustained winds, storm surges and torrential rain into Houston Electric's service territory. The May 2024 Storm Events and Hurricane Beryl caused significant damage to Houston Electric's electric delivery system and resulted in electric service interruptions peaking at an estimated 922,000 customers and more than 2.1 million customers, respectively.

Various federal, state and local governmental and regulatory agencies and other entities, such as the Texas Governor's office, the Texas legislature and the PUCT, have called for or are conducting inquiries and investigations into Hurricane Beryl, the efforts made by Houston Electric to prepare for, and respond to, this event, including the electric service outage issues, and the procurement of TEEEF. Moreover, additional governmental and regulatory agencies and other entities may conduct such inquiries and investigations, as well. On August 12, 2024, Texas Attorney General Ken Paxton opened an investigation to evaluate CenterPoint Energy's conduct during Hurricane Beryl. Texas Lieutenant Governor Patrick has publicly urged the PUCT to hold Houston Electric, rather than ratepayers, responsible for paying $800 million, which was the amount the PUCT had previously approved Houston Electric to recover from ratepayers pursuant to Texas legislation passed after the 2021 Winter Storm Event relating to emergency responsiveness and the leasing of temporary generation units. Additionally, legislation has been proposed in Texas to, among other things, require the PUCT to review TEEEF leased by TDUs, disallow any leases that do not conform to the terms of the proposed legislation (which include, among other things, requirements relating to the speed with which TEEEF may be deployed), disallow recovery of costs associated with such disallowed leases, and implement a process to refund ratepayers the charges paid for the leasing of certain TEEEF. There are significant uncertainties around these inquiries and investigations and potential results and consequences, including with respect to our recovery of costs incurred as a result of Hurricane Beryl and whether any financial penalties will be assessed or changes to Houston Electric's system, service territories, operations and/or regulatory treatment will result therefrom. Further, on January 22, 2025, a putative shareholder of CenterPoint Energy, Donel Davidson, filed a derivative petition in Harris County District Court, Texas, alleging breach of fiduciary duty and unjust enrichment on behalf of CenterPoint Energy against certain of its current and former directors and officers citing, in part, the topics of these inquiries and investigations. The action seeks to recover damages and other relief from the defendants on behalf of CenterPoint Energy. Additionally, on February 12, 2025, a second putative shareholder of CenterPoint Energy made a demand on the Board to investigate the same basic allegations raised in the derivative petition filed by Donel Davidson.

Houston Electric announced an initial hurricane preparedness and response action plan to the PUCT on July 25, 2024 to enhance the resiliency of the electric system through various investments. Following a meeting with Texas Governor Abbott on August 1, 2024, Houston Electric publicly committed to accelerating its previously announced initial hurricane preparedness and response action plan. Accordingly, Houston Electric announced that it was withdrawing its application for approval of its transmission and distribution system resiliency plan with the PUCT in order to focus on addressing the impacts of Hurricane Beryl in its service territory and accelerating preparedness and resiliency efforts for the remaining storm season, and the withdrawal granted by the PUCT. On August 5, 2024, Houston Electric announced the launch of its GHRI. Subsequently, Houston Electric announced the completion of core resiliency actions as part of the first phase of its GHRI, which included certain vegetation management and pole installation goals. In September 2024, Houston Electric announced the launch of the second phase of its GHRI, which included a series of resiliency plans to install new poles, manage higher-risk vegetation and install certain automated devices prior to the start of the 2025 hurricane season as part of its efforts to strengthen grid resiliency, improve public and customer communications and strengthen local, community and emergency partnerships. Following feedback from customers, external experts and other stakeholders, including elected officials and local agencies, Houston Electric filed the SRP with the PUCT on January 31, 2025, which proposes investing approximately $5.75 billion over a three-year period for transmission and distribution infrastructure, information technology and cybersecurity assets, and event response capability.

Houston Electric announced on August 28, 2024 its proposal to forego approximately $110 million of profit related to its storm hardening and TEEEF efforts, which would be represented by (1) Houston Electric not seeking to recover approximately $70 million in incremental storm hardening costs incurred in connection with accelerated operational activities after Hurricane Beryl; and (2) Houston Electric not filing, beginning in 2028, for approximately $40 million in anticipated equity profit associated with load-shed orientated TEEEF leased by Houston Electric through the remaining regulatory life of the leases in 2032 as new dispatchable generation is likely to come online in the state of Texas as a result of the Texas Energy Fund. Additionally, on December 19, 2024, Houston Electric announced a proposal to release Houston Electric's 15 large 27 MW to 32 MW TEEEF units to the San Antonio area prior to the summer of 2025 in an effort to help ERCOT address a potential energy shortfall and Load Shed risk and to provide additional electric generation capacity to support growing energy demand in the greater San Antonio region. Under the proposal, Houston Electric would not receive revenue or profit from ERCOT and would also not charge Houston-area customers for these TEEEF units for the period when they are in San Antonio serving ERCOT, which is currently expected to be for a period of up to two years. Houston Electric would anticipate receiving revenues from one or more future transactions after the period the units are utilized to temporarily serve an energy need in the San Antonio area, and would therefore plan to continue to not charge customers for these units for any future periods. As of the date of the filing of this Form 10-K, Houston Electric estimates that the value of the TEEEF units to be removed from the rate base as a result of the aforementioned proposal will be approximately $375 million. The proposal has not been finalized and is subject to the negotiation of definitive documentation among the relevant parties, as well as being subject to the approval of ERCOT and other stakeholders. It is not certain that mutually agreeable definitive documentation will be entered into at all or that all approvals will be obtained.

For more information, see Note 7, 12 and 14 to the consolidated financial statements and "Liquidity and Capital Resources" below.

Equity Transactions. On August 9, 2024, CenterPoint Energy issued 9,754,194 shares of Common Stock in an underwritten public offering at a price of $25.36 per share, for net proceeds of $247 million after deducting issuance costs. For further information, see Note 11 to the consolidated financial statements.

On January 10, 2024, CenterPoint Energy entered into an Equity Distribution Agreement with certain financial institutions with respect to the offering and sale from time to time of shares of Common Stock, having an aggregate gross sales price of up to $500 million. Sales of Common Stock may be made by any method permitted by applicable law and deemed to be an "at the market offering" as defined in Rule 415 of the Securities Act of 1933, as amended. CenterPoint Energy may also enter into one or more forward sales agreements pursuant to master forward confirmations. During the year ended December 31, 2024, CenterPoint Energy issued 8,790,848 shares of Common Stock through the ATM Managers under the Equity Distribution Agreement, representing aggregate cash proceeds of $247 million, which was net of compensation paid by CenterPoint Energy to the ATM Managers of $2 million. As of December 31, 2024, CenterPoint Energy had not entered into any forward sale agreements under the at-the-market program. Additionally, as of December 31, 2024, CenterPoint Energy had $250 million of remaining capacity available under the program. For further information, see Note 11 to the consolidated financial statements.

Assets Held for Sale. On February 19, 2024, CERC Corp. entered into the LAMS Asset Purchase Agreement to sell its Louisiana and Mississippi natural gas LDC businesses. The purchase price for the Louisiana and Mississippi natural gas LDC businesses is $1.2 billion and subject to adjustment as set forth in the LAMS Asset Purchase Agreement, including adjustments based on net working capital, regulatory assets and liabilities and capital expenditures at closing. The transaction is not subject to a financing condition and is expected to close by the end of the first quarter of 2025, subject to satisfaction of customary closing conditions. The businesses include approximately 12,000 miles of main pipeline in Louisiana and Mississippi serving more than 300,000 customers. The Louisiana and Mississippi natural gas LDC businesses are reflected in CenterPoint Energy's Natural Gas reportable segment and CERC's single reportable segment, as applicable. For further information, see Note 4 to the consolidated financial statements.

Regulatory Proceedings. For further information, see Note 7 to the consolidated financial statements. For information related to our pending and completed regulatory proceedings to date in 2024 and to date in 2025, see "—Liquidity and Capital Resources —Regulatory Matters" below.

Debt Transactions. In 2024, CenterPoint Energy issued or borrowed a combined $4.0 billion in new debt, including Houston Electric's issuance of $900 million aggregate principal amount of general mortgage bonds and a $500 million term loan, CERC's issuance of $400 million principal amount of senior notes, SIGECO's issuance of $160 million aggregate principal amount of first mortgage bonds, and CenterPoint Energy's issuance of $700 million aggregate principal amount of senior notes and $1.3 billion aggregate principal amount of junior subordinated notes. During 2024, CenterPoint Energy repaid or redeemed a combined $0.9 billion of debt, including $500 million of its senior notes, $350 million of its floating rate senior notes and $22 million of SIGECO's first mortgage bonds. For further information about debt transactions in 2024, see Note 12

to the consolidated financial statements.

Subsequent Events. On January 29, 2025, CenterPoint Energy, Houston Electric, CERC and SIGECO each entered into Extension Agreements to, among other things, extend the maturity date of the lenders' commitments under each of their respective Credit Agreements by one year, from December 6, 2027 to December 6, 2028.

Additionally, on January 31, 2025, SIGECO issued $165 million aggregate principal amount of 5.69% First Mortgage Bonds, Series 2025A, Tranche A due 2055. Total net proceeds from SIGECO's January 2025 issuance of first mortgage bonds, net of transaction expenses and fees, were approximately $164 million, which will be used for the acquisition of Posey Solar.

CERTAIN FACTORS AFFECTING FUTURE EARNINGS

Our past earnings and results of operations are not necessarily indicative of our future earnings and results of operations. The magnitude of our future earnings and results of our operations will depend on or be affected by numerous factors that apply to all Registrants unless otherwise indicated including:

- The business strategies and strategic initiatives, restructurings, joint ventures and acquisitions or dispositions of assets or businesses involving us or our industry, including the ability to successfully complete such strategies, initiatives, transactions or plans on the timelines we expect or at all, such as the announced sale of our Louisiana and Mississippi natural gas LDC businesses, which we cannot assure will have the anticipated benefits to us;
- industrial, commercial and residential growth in our service territories and changes in market demand, including in relation to the expansion of data centers, energy export facilities, including hydrogen facilities, electrification of industrial processes and transport and logistics, as well as the effects of energy efficiency measures and demographic patterns;
- our ability to fund and invest planned capital and the timely recovery of our investments, including the timing of and amounts sought for those related to Indiana Electric's generation transition plan as part of its IRPs and Houston Electric's GHRI and SRP;
- our ability to successfully construct, operate, repair and maintain electric generating facilities, natural gas facilities, TEEEF and electric transmission facilities, including complying with applicable environmental standards and the implementation of a well-balanced energy and resource mix, as appropriate;
- timely and appropriate rate actions that allow and authorize timely recovery of costs and a reasonable return on investment, including the timing of and amounts sought for recovery of Houston Electric's TEEEF leases and restoration costs relating to the May 2024 Storm Events and Hurricane Beryl, and requested or favorable adjustments to rates and approval of other requested items as part of base rate proceedings;
- our ability to finalize Houston Electric's proposal to release its 15 large 27 MW to 32 MW TEEEF units to the San Antonio area and complete one or more other future transactions involving the units on acceptable terms and conditions within the anticipated timeframe;
- economic conditions in regional and national markets, including changes to inflation and interest rates, and their effect on sales, prices and costs;
- weather variations and other natural phenomena, including the impact of severe weather events on operations, capital, legislation and/or regulations, such as in connection with the February 2021 Winter Storm Event, the May 2024 Storm Events and Hurricane Beryl;
- volatility in the markets for natural gas as a result of, among other factors, tariffs, legislation, bans, potential retaliatory trade measures taken against the United States or related governmental action, as well as armed conflicts, including the conflict in the Middle East and any broader related conflict, and the conflict in Ukraine, and the related sanctions on certain Russian entities;
- disruptions to the global supply chain, including as a result of volatility in commodity prices, trade agreements, geopolitical and economic uncertainty, regulatory and policy instability, severe weather events, tariffs, bans, retaliatory trade measures, legislation and governmental action impacting the supply chain, that could prevent CenterPoint Energy from securing the resources needed to, among other things, fully execute on its 10-year capital plan or achieve its net zero and GHG emissions reduction goals;
- non-payment for our services due to financial distress of our customers and the ability of our customers, including REPs, to satisfy their obligations to CenterPoint Energy, Houston Electric and CERC, and the negative impact on such ability related to adverse economic conditions and severe weather events;
- public health threats, and their effect on our operations, business and financial condition, our industries and the communities we serve, U.S. and world financial markets and supply chains, potential regulatory actions and changes in customer and stakeholder behavior relating thereto;
- state and federal legislative and regulatory actions or developments affecting various aspects of our businesses, including, among others, any actions resulting from the May 2024 Storm Events and/or Hurricane Beryl, energy

deregulation or re-regulation, pipeline integrity and safety and changes in regulation and legislation pertaining to trade, health care, finance and actions regarding the rates charged by our regulated businesses;
- our ability to execute Houston Electric's GHRI and SRP;
- direct or indirect effects on our facilities, resources, operations, reputation and financial condition resulting from terrorism, cyberattacks or intrusions, data security breaches or other attempts to disrupt our businesses or the businesses of third parties, or other catastrophic events such as fires, earthquakes, explosions, leaks, floods, droughts, hurricanes, tornadoes, derecho events, ice storms and other severe weather events, terrorism, wildfires, pandemic health events, geopolitical conflict or other occurrences;
- risks relating to potential wildfires, including damages to our network and losses in excess of insurance liability coverage;
- tax legislation, including the effects of or changes to or the repeal of the IRA (which includes but is not limited to any potential changes to tax rates, CAMT imposed, tax credits and/or interest deductibility), as well as any changes in tax laws under the current or future administrations, and uncertainties involving state commissions' and local municipalities' regulatory requirements and determinations regarding the treatment of EDIT and our rates;
- our ability to mitigate weather impacts through normalization or rate mechanisms, and the effectiveness of such mechanisms;
- actions by credit rating agencies, including any potential downgrades to credit ratings;
- matters affecting regulatory approval, legislative actions, construction, implementation of necessary technology or other issues with respect to major capital projects that result in delays or cancellation or in costs that cannot be recouped in rates;
- local, state and federal legislative and regulatory actions or developments relating to the environment, including, among others, those related to global climate change, air emissions, GHG emissions, carbon emissions, wastewater discharges and the handling and disposal of CCR that could impact operations, cost recovery of generation plant costs and related assets, and CenterPoint Energy's net zero and GHG emissions reduction goals;
- the impact of unplanned facility outages or other closures;
- the sufficiency of our insurance coverage, including availability, cost, coverage and terms and ability to recover claims;
- the availability and prices of raw materials and services and changes in labor for current and future construction projects and operations and maintenance costs, including our ability to control such costs;
- impacts from CenterPoint Energy's pension and postretirement benefit plans, such as the investment performance and increases to net periodic costs as a result of plan settlements and changes in assumptions, including discount rates;
- changes in interest rates and their impact on costs of borrowing and the valuation of CenterPoint Energy's pension benefit obligation;
- commercial bank and financial market conditions, including disruptions in the banking industry, our access to capital, the cost of such capital, the results of our financing and refinancing efforts, including availability of funds in the debt capital markets, and impacts on our vendors, customers and suppliers;
- inability of various counterparties to meet their obligations to us;
- the extent and effectiveness of our risk management activities;
- timely and appropriate regulatory actions, which include actions allowing requested securitization for any hurricanes or other severe weather events, such as the May 2024 Storm Events and Hurricane Beryl, or natural disasters or other amounts sought for recovery of costs, including stranded coal-fired generation asset costs;
- our ability to attract, effectively transition, motivate and retain management and key employees and maintain good labor relations;
- changes in technology, particularly with respect to efficient battery storage or the emergence or growth of new, developing or alternative sources of generation, and their adoption by consumers, and our ability to anticipate and adapt to technological changes;
- our success in adopting, developing and deploying AI;
- the impact of climate change and alternate energy sources on the demand for natural gas and electricity generated or transmitted by us;
- the timing and outcome of any audits, disputes and other proceedings related to taxes;
- the recording of impairment charges;
- political and economic developments and actions, including energy and environmental policies under the new presidential administration;
- CenterPoint Energy's ability to execute on its strategy, initiatives, targets and goals, including its net zero and GHG emissions reduction goals and its operations and maintenance expenditure goals;
- the outcome of litigation, including litigation related to the February 2021 Winter Storm Event and Hurricane Beryl;
- the effect of changes in and application of accounting standards and pronouncements; and
- other factors discussed in "Risk Factors" in Part I, Item 1A of this report and in other reports that the Registrants file from time to time with the SEC.

CENTERPOINT ENERGY CONSOLIDATED RESULTS OF OPERATIONS

CenterPoint Energy's results of operations are affected by seasonal fluctuations in the demand for electricity and natural gas. CenterPoint Energy's results of operations are also affected by, among other things, the actions of various governmental authorities having jurisdiction over rates its subsidiaries charge, debt service costs, income tax expense, its subsidiaries ability to collect receivables from REPs and customers and its ability to recover its regulatory assets. For information regarding factors that may affect the future results of our consolidated operations, read "Risk Factors" in Part I, Item 1A of this report.

Income available to common shareholders for the years ended December 31, 2024, 2023 and 2022 was as follows:

	Year Ended December 31,			Favorable (Unfavorable)	
	2024	2023	2022	2024 to 2023	2023 to 2022
			(in millions)		
Electric	$ 671	$ 654	$ 603	$ 17	$ 51
Natural Gas	564	533	492	31	41
Total Utility Operations	1,235	1,187	1,095	48	92
Corporate & Other (1)	(216)	(320)	(87)	104	(233)
Total CenterPoint Energy	$ 1,019	$ 867	$ 1,008	$ 152	$ (141)

(1) Includes energy performance contracting and sustainable infrastructure services through Energy Systems Group through the date of sale on June 30, 2023, unallocated corporate costs, interest income and interest expense, intercompany eliminations and the reduction of income allocated to preferred shareholders through September 1, 2023, the date of the redemption of all of the outstanding shares of the Series A Preferred Stock.

2024 Compared to 2023

CenterPoint Energy reported income available to common shareholders of $1,019 million for 2024 compared to income available to common shareholders of $867 million for 2023.

Income available to common shareholders increased $152 million primarily due to the following items:

- an increase in income available to common shareholders of $17 million for the Electric reportable segment, as further discussed below;
- an increase in income available to common shareholders of $31 million for the Natural Gas reportable segment, as further discussed below; and
- an increase in income available to common shareholders of $104 million for Corporate and Other, primarily due to $50 million of income allocated to holders of Series A Preferred Stock in 2023 prior to the redemption of all outstanding shares of Series A Preferred Stock in September 2023 as discussed in Note 11 to the consolidated financial statements, a loss on sale of $13 million and current tax expense of $32 million related to the divestiture of Energy Systems Group recorded in 2023 further discussed in Note 4 to the consolidated financial statements, $19 million due to remeasurement of deferred income tax balances recorded during 2023, as well as $8 million due to lower state income taxes. The remaining variance is due largely to an increase in borrowing costs.

2023 Compared to 2022

CenterPoint Energy reported income available to common shareholders of $867 million for 2023 compared to income available to common shareholders of $1,008 million for 2022.

Income available to common shareholders decreased $141 million primarily due to the following items:

- an increase in income available to common shareholders of $51 million for the Electric reportable segment, as further discussed below;
- an increase in income available to common shareholders of $41 million for the Natural Gas reportable segment, as further discussed below; and
- a decrease in income available to common shareholders of $233 million for Corporate and Other, primarily due to a pre-tax net gain of $86 million on the sale of Energy Transfer equity securities in 2022 further discussed in Note 10 to the consolidated financial statements, partially offset by $45 million of costs associated with early redemption of long-term debt in first quarter 2022. The decrease is also due to a loss on sale of $13 million and current tax expense of

$32 million related to the divestiture of Energy Systems Group further discussed in Note 4 to the consolidated financial statements, as well as $19 million due to remeasurement of deferred income tax balances. The remaining variance is due largely to an increase in borrowing costs.

Income Tax Expense. For a discussion of effective tax rate per period, see Note 13 to the consolidated financial statements.

CENTERPOINT ENERGY'S RESULTS OF OPERATIONS BY REPORTABLE SEGMENT

CenterPoint Energy's CODM views net income as the measure of profit or loss for the reportable segments. Segment results include inter-segment interest income and expense, which may result in inter-segment profit and loss.

The following discussion of CenterPoint Energy's results of operations is separated into two reportable segments, Electric and Natural Gas.

Electric (CenterPoint Energy)

The following table provides summary data of CenterPoint Energy's Electric reportable segment:

	Year Ended December 31,			Favorable (Unfavorable)	
	2024	2023	2022	2024 to 2023	2023 to 2022
	(in millions, except throughput, weather and customer data)				
Revenues	$ 4,590	$ 4,290	$ 4,108	$ 300	$ 182
Expenses:					
Utility natural gas, fuel and purchased power	198	176	222	(22)	46
Operation and maintenance	2,072	1,880	1,864	(192)	(16)
Depreciation and amortization	877	872	793	(5)	(79)
Taxes other than income taxes	304	272	275	(32)	3
Total expenses	3,451	3,200	3,154	(251)	(46)
Operating Income	1,139	1,090	954	49	136
Other Income (Expense):					
Interest expense and other finance charges	(372)	(303)	(235)	(69)	(68)
Other income, net	61	56	31	5	25
Income Before Income Taxes	828	843	750	(15)	93
Income tax expense	157	189	147	32	(42)
Net Income	$ 671	$ 654	$ 603	$ 17	$ 51
Throughput (in GWh):					
Residential	34,190	35,166	35,074	(3)%	— %
Total	110,831	108,766	105,541	2 %	3 %
Weather (percentage of normal weather for service area):					
Cooling degree days	115 %	114 %	110 %	1 %	4 %
Heating degree days	76 %	90 %	121 %	(14)%	(31)%
Number of metered customers at end of period:					
Residential	2,640,150	2,588,510	2,534,730	2 %	2 %
Total	2,971,730	2,916,028	2,858,203	2 %	2 %

The following table provides variance explanations by major income statement caption for the Electric reportable segment:

	Favorable (Unfavorable)	
	2024 to 2023	2023 to 2022
	(in millions)	
Revenues		
Customer rates and impact of the change in rate design	$ 143	$ 167
Transmission Revenues, including TCOS and TCRF, inclusive of costs billed by transmission providers, partially offset in operation and maintenance below	217	122
Customer growth	26	26
Energy efficiency, offset in operation and maintenance below	5	—
Equity return, related to the annual true-up of transition charges for amounts over or under collected in prior periods	(20)	(5)
Pass-through revenues, offset in operation and maintenance below	(5)	(13)
Miscellaneous revenues, including service connections and off-system sales	1	(14)
Lost revenues as a result of outages associated with Hurricane Beryl	(10)	—
Bond Companies and SIGECO Securitization Subsidiary, offset in other line items below	(70)	(27)
Weather, efficiency improvements and other usage impacts	(9)	(28)
Cost of fuel and purchased power, offset in utility natural gas, fuel and purchased power below	22	(46)
Total	$ 300	$ 182
Utility natural gas, fuel and purchased power		
Cost of purchased power, offset in revenues above	$ (87)	$ 30
Cost of fuel, including coal, natural gas, and fuel oil, offset in revenues above	65	16
Total	$ (22)	$ 46
Operation and maintenance		
Transmission costs billed by transmission providers, offset in revenues above	$ (124)	$ (26)
Incremental storm expenses, including storm hardening expenses incurred in connection with accelerated operational activities after Hurricane Beryl	(112)	—
Contract services	16	(21)
Energy efficiency, and other pass-through, offset in revenues above	(1)	3
Corporate support services	—	(8)
Labor and benefits	4	7
All other operation and maintenance expense, including materials and supplies and insurance	25	29
Total	$ (192)	$ (16)
Depreciation and amortization		
Ongoing additions to plant-in-service	$ (79)	$ (106)
Bond Companies and SIGECO Securitization Subsidiary, offset in other line items	74	27
Total	$ (5)	$ (79)
Taxes other than income taxes		
Incremental capital projects placed in service, and the impact of updated property tax rates	$ (26)	$ 2
Franchise fees and other taxes	(6)	1
Total	$ (32)	$ 3
Interest expense and other finance charges		
Changes in outstanding debt	$ (63)	$ (76)
Bond Companies and SIGECO Securitization Subsidiary, offset in other line items above	(4)	(4)
Other, primarily AFUDC and impacts of regulatory deferrals	(2)	12
Total	$ (69)	$ (68)
Other income (expense), net		
Other income, including AFUDC - equity	$ 5	$ 21
Bond Companies and SIGECO Securitization Subsidiary, offset in other line items above	—	4
Total	$ 5	$ 25

Income Tax Expense. For a discussion of effective tax rate per period by Registrant, see Note 13 to the consolidated financial statements.

Natural Gas (CenterPoint Energy)

The following table provides summary data of CenterPoint Energy's Natural Gas reportable segment:

	Year Ended December 31,			Favorable (Unfavorable)	
	2024	2023	2022	2024 to 2023	2023 to 2022
	(in millions, except throughput, weather and customer data)				
Revenues	$ 4,048	$ 4,279	$ 4,946	$ (231)	$ (667)
Expenses:					
Utility natural gas and fuel	1,520	1,888	2,665	368	777
Non-utility cost of revenues, including natural gas	3	3	4	—	1
Operation and maintenance	881	949	919	68	(30)
Depreciation and amortization	542	513	466	(29)	(47)
Taxes other than income taxes	237	245	261	8	16
Total expenses	3,183	3,598	4,315	415	717
Operating Income	865	681	631	184	50
Other Income (Expense):					
Gain on sale	—	—	303	—	(303)
Interest expense and other finance charges	(207)	(188)	(137)	(19)	(51)
Other income (expense), net	14	15	(62)	(1)	77
Income Before Income Taxes	672	508	735	164	(227)
Income tax expense (benefit)	108	(25)	243	(133)	268
Net Income	$ 564	$ 533	$ 492	$ 31	$ 41
Throughput (in Bcf):					
Residential	189	199	240	(5)%	(17)%
Commercial and industrial	426	418	424	2 %	(1)%
Total Throughput	615	617	664	— %	(7)%
Weather (percentage of 10-year average for service area):					
Heating degree days	78 %	86 %	106 %	(8)%	(20)%
Number of metered customers at end of period:					
Residential	4,063,928	4,010,113	3,964,221	1 %	1 %
Commercial and industrial	304,606	303,841	301,834	— %	1 %
Total	4,368,534	4,313,954	4,266,055	1 %	1 %

The following table provides variance explanations by major income statement caption for the Natural Gas reportable segment:

	Favorable (Unfavorable)	
	2024 to 2023	2023 to 2022
	(in millions)	
Revenues		
Cost of natural gas, offset in utility natural gas and fuel below	$ (368)	$ (754)
Nine days in January 2022 for Arkansas and Oklahoma Natural Gas businesses due to sale	—	(38)
Gross receipts tax, offset in taxes other than income taxes below	1	(17)
Weather and usage	(11)	(7)
Non-volumetric and miscellaneous revenue	(7)	14
Energy efficiency and other pass-through, offset in operation and maintenance below	(20)	17
Non-utility revenues	15	18
Customer growth	14	20
Customer rates	145	80
Total	$ (231)	$ (667)
Utility natural gas and fuel		
Cost of natural gas, offset in revenues above	$ 368	$ 754
Nine days in January 2022 for Arkansas and Oklahoma Natural Gas businesses due to sale	—	23
Total	$ 368	$ 777
Non-utility costs of revenues, including natural gas		
Non-utility cost of revenues, including natural gas	$ —	$ 1
Total	$ —	$ 1
Operation and maintenance		
All other operations and maintenance expenses, including bad debt expense	$ 23	$ (36)
Energy efficiency and other pass-through, offset in revenues above	20	(17)
Contract services	(6)	(3)
Nine days in January 2022 for Arkansas and Oklahoma Natural Gas businesses due to sale	—	3
Labor and benefits	8	11
Corporate support services	23	12
Total	$ 68	$ (30)
Depreciation and amortization		
Ongoing additions to plant-in-service	$ (29)	$ (49)
Nine days in January 2022 for Arkansas and Oklahoma Natural Gas businesses due to sale	—	2
Total	$ (29)	$ (47)
Taxes other than income taxes		
Gross receipts tax, offset in revenues above	$ (1)	$ 17
Nine days in January 2022 for Arkansas and Oklahoma Natural Gas businesses due to sale	—	1
Incremental capital projects placed in service, and the impact of updated property tax rates	9	(2)
Total	$ 8	$ 16
Gain on Sale		
Gain on Sale of Arkansas and Oklahoma Natural Gas businesses in 2022	$ —	$ (303)
Total	$ —	$ (303)
Interest expense and other finance charges		
Changes in outstanding debt	$ (12)	$ (59)
Other, primarily AFUDC and impacts of regulatory deferrals	(7)	8
Total	$ (19)	$ (51)
Other income (expense), net		
Changes to non-service benefit cost, primarily settlement cost incurred in 2022	$ 3	$ 60
Other income, including AFUDC - Equity	3	10
Other	(7)	7
Total	$ (1)	$ 77

Income Tax Expense (Benefit). For a discussion of effective tax rate per period by Registrant, see Note 13 to the consolidated financial statements.

HOUSTON ELECTRIC CONSOLIDATED RESULTS OF OPERATIONS

Houston Electric's CODM views net income as the measure of profit or loss for its reportable segment. Houston Electric consists of a single reportable segment. Houston Electric's results of operations are affected by seasonal fluctuations in the demand for electricity. Houston Electric's results of operations are also affected by, among other things, the actions of various governmental authorities having jurisdiction over rates Houston Electric charges, debt service costs, income tax expense, Houston Electric's ability to collect receivables from REPs and Houston Electric's ability to recover its regulatory assets. For information regarding factors that may affect the future results of Houston Electric's consolidated operations, read "Risk Factors" in Item 1A of Part I of this report.

The following table provides summary data of Houston Electric's single reportable segment:

	Year Ended December 31,			Favorable (Unfavorable)	
	2024	2023	2022	2024 to 2023	2023 to 2022
	(in millions, except throughput, weather and customer data)				
Revenues:					
TDU	$ 3,862	$ 3,514	$ 3,205	$ 348	$ 309
Bond Companies	77	163	207	(86)	(44)
Total revenues	3,939	3,677	3,412	262	265
Expenses:					
Operation and maintenance, excluding Bond Companies	1,923	1,669	1,647	(254)	(22)
Depreciation and amortization, excluding Bond Companies	688	593	479	(95)	(114)
Taxes other than income taxes	295	262	261	(33)	(1)
Bond Companies	78	159	194	81	35
Total	2,984	2,683	2,581	(301)	(102)
Operating Income	955	994	831	(39)	163
Other Income (Expense):					
Interest expense and other finance charges	(311)	(259)	(202)	(52)	(57)
Interest expense on Securitization Bonds	(3)	(8)	(13)	5	5
Other income, net	43	34	19	9	15
Income Before Income Taxes	684	761	635	(77)	126
Income tax expense	138	168	125	30	(43)
Net Income	$ 546	$ 593	$ 510	$ (47)	$ 83
Throughput (in GWh):					
Residential	32,769	33,830	33,676	(3)%	— %
Total	106,014	103,862	100,062	2 %	4 %
Weather (percentage of 10-year average for service area):					
Cooling degree days	115 %	114 %	110 %	1 %	4 %
Heating degree days	92 %	92 %	120 %	— %	(28)%
Number of metered customers at end of period:					
Residential	2,506,284	2,455,309	2,402,329	2 %	2 %
Total	2,818,343	2,763,535	2,706,598	2 %	2 %

The following table provides variance explanations by major income statement caption for Houston Electric:

	Favorable (Unfavorable)	
	2024 to 2023	2023 to 2022
	(in millions)	
Revenues		
Customer rates and impact of the change in rate design	$ 153	$ 187
Transmission Revenues, including TCOS and TCRF, inclusive of costs billed by transmission providers, partially offset in operation and maintenance below	217	120
Customer growth	25	25
Energy efficiency, partially offset in operation and maintenance below	5	1
Miscellaneous revenues	1	(4)
Lost revenues as a result of outages associated with Hurricane Beryl	(10)	—
Equity return, related to the annual true-up of transition charges for amounts over or under collected in prior periods	(19)	(5)
Weather, efficiency improvements and other usage impacts	(24)	(15)
Bond Companies, offset in other line items below	(86)	(44)
Total	$ 262	$ 265
Operation and maintenance, excluding Bond Companies		
Transmission costs billed by transmission providers, offset in revenues above	$ (124)	$ (26)
Incremental storm expenses, including storm hardening expenses incurred in connection with accelerated operational activities after Hurricane Beryl	(112)	—
Contract services	7	(23)
Energy efficiency, offset in revenues above	(6)	(8)
Corporate support services	(2)	(6)
Labor and benefits	1	3
All other operation and maintenance expense, including materials and supplies and insurance	(18)	38
Total	$ (254)	$ (22)
Depreciation and amortization, excluding Bond Companies		
Ongoing additions to plant-in-service	$ (95)	$ (114)
Total	$ (95)	$ (114)
Taxes other than income taxes		
Franchise fees and other taxes	$ (7)	$ (2)
Incremental capital projects placed in service, and the impact of changes to tax rates	(26)	1
Total	$ (33)	$ (1)
Bond Companies expense		
Operations and maintenance and depreciation expense, offset in revenues above	$ 81	$ 35
Total	$ 81	$ 35
Interest expense and other finance charges		
Changes in outstanding debt	$ (55)	$ (64)
Other, primarily AFUDC and impacts of regulatory deferrals	3	7
Total	$ (52)	$ (57)
Interest expense on Securitization Bonds		
Lower outstanding principal balance, offset in revenues above	$ 5	$ 5
Total	$ 5	$ 5
Other income, net		
Other income, including AFUDC - equity	$ 9	$ 11
Bond Companies	—	4
Total	$ 9	$ 15

Income Tax Expense. For a discussion of effective tax rate per period, see Note 13 to the consolidated financial statements.

CERC CONSOLIDATED RESULTS OF OPERATIONS

CERC's CODM views net income as the measure of profit or loss for its reportable segment. CERC consists of a single reportable segment. CERC's results of operations are affected by seasonal fluctuations in the demand for natural gas. CERC's results of operations are also affected by, among other things, the actions of various federal, state and local governmental authorities having jurisdiction over rates CERC charges, debt service costs and income tax expense, CERC's ability to collect receivables from customers and CERC's ability to recover its regulatory assets. For information regarding factors that may affect the future results of CERC's consolidated operations, read "Risk Factors" in Item 1A of Part I of this report.

The following table provides summary data of CERC's single reportable segment:

	Year Ended December 31,			Favorable (Unfavorable)	
	2024	2023	2022	2024 to 2023	2023 to 2022
	(in millions, except throughput, weather and customer data)				
Revenues	$ 3,925	$ 4,149	$ 4,800	$ (224)	$ (651)
Expenses:					
Utility natural gas	1,489	1,856	2,607	367	751
Non-utility cost of revenues, including natural gas	3	3	4	—	1
Operation and maintenance	848	904	886	56	(18)
Depreciation and amortization	522	493	448	(29)	(45)
Taxes other than income taxes	234	243	257	9	14
Total expenses	3,096	3,499	4,202	403	703
Operating Income	829	650	598	179	52
Other Income (Expense):					
Gain on sale	—	—	557	—	(557)
Interest expense and other finance charges	(197)	(178)	(130)	(19)	(48)
Other income (expense), net	12	14	(64)	(2)	78
Income Before Income Taxes	644	486	961	158	(475)
Income tax expense (benefit)	104	(26)	236	(130)	262
Net Income	$ 540	$ 512	$ 725	$ 28	$ (213)
Throughput (in BCF):					
Residential	184	194	233	(5)%	(17)%
Commercial and Industrial	390	386	389	1 %	(1)%
Total Throughput	574	580	622	(1)%	(7)%
Weather (percentage of 10-year average for service area):					
Heating degree days	78 %	86 %	106 %	(8)%	(20)%
Number of metered customers at end of period:					
Residential	3,958,584	3,905,388	3,859,726	1 %	1 %
Commercial and Industrial	293,959	293,235	291,184	— %	1 %
Total	4,252,543	4,198,623	4,150,910	1 %	1 %

The following table provides variance explanations by major income statement caption for CERC:

	Favorable (Unfavorable)	
	2024 to 2023	2023 to 2022
	(in millions)	
Revenues		
Cost of natural gas, offset in utility natural gas, fuel and purchased power below	$ (367)	$ (728)
Nine days in January 2022 for Arkansas and Oklahoma Natural Gas businesses due to sale	—	(38)
Gross receipts tax, offset in taxes other than income taxes below	1	(15)
Weather and usage	(9)	(7)
Energy efficiency and other pass-through, offset in operation and maintenance below	(10)	8
Non-volumetric and miscellaneous revenue	(6)	13
Non-utility revenues	15	18
Customer growth	13	20
Customer rates	139	78
Total	$ (224)	$ (651)
Utility natural gas		
Cost of natural gas, offset in revenues above	$ 367	$ 728
Nine days in January 2022 for Arkansas and Oklahoma Natural Gas businesses due to sale	—	23
Total	$ 367	$ 751
Non-utility costs of revenues, including natural gas		
Other, primarily non-utility cost of revenues	$ —	$ 1
Total	$ —	$ 1
Operation and maintenance		
All other operations and maintenance expenses, including bad debt expense	$ 21	$ (36)
Energy efficiency and other pass-through, offset in revenues above	10	(8)
Contract services	(6)	—
Nine days in January 2022 for Arkansas and Oklahoma Natural Gas businesses due to sale	—	3
Labor and benefits	8	11
Corporate support services	23	12
Total	$ 56	$ (18)
Depreciation and amortization		
Ongoing additions to plant-in-service	$ (29)	$ (47)
Indiana lower depreciation rates from recent rate order	—	—
Nine days in January 2022 for Arkansas and Oklahoma Natural Gas businesses due to sale	—	2
Total	$ (29)	$ (45)
Taxes other than income taxes		
Gross receipts tax, offset in revenues above	$ (1)	$ 15
Nine days in January 2022 for Arkansas and Oklahoma Natural Gas businesses due to sale	—	1
Incremental capital projects placed in service, and the impact of updated property tax rates	10	(2)
Total	$ 9	$ 14
Gain on sale		
Net gain on sale of Arkansas and Oklahoma Natural Gas businesses	$ —	$ (557)
Total	$ —	$ (557)
Interest expense and other finance charges		
Changes in outstanding debt	$ (11)	$ (56)
Other, primarily AFUDC and impacts of regulatory deferrals	(8)	8
Total	$ (19)	$ (48)
Other income (expense), net		
Changes to non-service benefit cost, primarily settlement cost incurred in 2022	$ 3	$ 60
Other income, including AFUDC - Equity	3	9
Other	(8)	9
Total	$ (2)	$ 78

Income Tax Expense (Benefit). For a discussion of effective tax rate per period, see Note 13 to the consolidated financial statements.

LIQUIDITY AND CAPITAL RESOURCES

Cash Flows

The following table summarizes the Registrants' cash flows by category for the periods presented:

	Year Ended December 31,								
	2024			2023			2022		
	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC
	(in millions)								
Cash provided by (used in):									
Operating activities	$ 2,139	$ 960	$ 1,068	$ 3,877	$ 1,401	$ 2,312	$ 1,810	$ 966	$ 856
Investing activities	(4,489)	(2,767)	(1,419)	(4,233)	(2,503)	(1,643)	(1,628)	(2,435)	406
Financing activities	2,271	1,732	352	374	1,103	(668)	(345)	1,324	(1,277)

Operating Activities. The following items contributed to increased (decreased) net cash provided by operating activities:

	2024 compared to 2023			2023 compared to 2022		
	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC
	(in millions)					
Changes in net income after adjusting for non-cash items	$ 315	$ (132)	$ 153	$ 394	$ 235	$ 170
Changes in working capital	(134)	195	(83)	917	229	358
Changes in current regulatory assets and liabilities (1)	(1,238)	(4)	(1,183)	1,085	26	986
Changes in non-current regulatory assets and liabilities	(535)	(472)	(85)	(276)	(115)	(78)
Lower pension contribution	2	—	—	3	—	—
Other	(148)	(28)	(46)	(56)	60	20
	$ (1,738)	$ (441)	$ (1,244)	$ 2,067	$ 435	$ 1,456

(1) This change is primarily related to the receipt of proceeds at CenterPoint Energy and CERC from the issuance of customer rate relief bonds Texas by the Natural Gas Securitization Finance Corporation in 2023. For further details, see Note 7 to the consolidated financial statements.

Investing Activities. The following items contributed to (increased) decreased net cash used in investing activities:

	2024 compared to 2023			2023 compared to 2022		
	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC
	(in millions)					
Proceeds from the sale of equity securities	$ —	$ —	$ —	$ (702)	$ —	$ —
Net change in capital expenditures	(112)	(363)	180	18	157	42
Net change in notes receivable from affiliated companies	—	108	2	—	(238)	(1)
Proceeds from divestitures	(144)	—	—	(1,931)	—	(2,075)
Other	—	(9)	42	10	13	(15)
	$ (256)	$ (264)	$ 224	$ (2,605)	$ (68)	$ (2,049)

Financing Activities. The following items contributed to (increased) decreased net cash provided by (used in) financing activities:

	2024 compared to 2023			2023 compared to 2022		
	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC
			(in millions)			
Net changes in commercial paper outstanding	$ 516	$ —	$ 436	$ (981)	$ —	$ (227)
Net changes in proceeds from issuance of Common Stock	494	—	—	—	—	—
Net changes in long-term debt and term loans outstanding, excluding commercial paper	51	(6)	725	2,560	373	(778)
Net changes in debt and equity issuance costs	20	5	11	(19)	4	—
Net changes in short-term borrowings	6	—	6	(462)	—	(462)
Redemption of Series A Preferred Stock	800	—	—	(800)	—	—
Increased payment of Common Stock dividends	(37)	—	—	(45)	—	—
Decreased (increased) payment of preferred stock dividends	50	—	—	(1)	—	—
Payment of obligation for finance lease	—	—	—	485	485	—
Net change in notes payable from affiliated companies	—	642	—	—	(772)	1,517
Change in contribution from parent	—	(41)	(210)	—	(258)	211
Change in dividend to parent	—	28	54	—	(51)	348
Other	(3)	1	(2)	(18)	(2)	—
	$ 1,897	$ 629	$ 1,020	$ 719	$ (221)	$ 609

Future Sources and Uses of Cash

Material Current and Long-term Cash Requirements. The liquidity and capital requirements of the Registrants are affected primarily by results of operations, capital expenditures, storm restoration costs, debt service requirements, tax payments, working capital needs and various regulatory actions. Capital expenditures (other than expenditures associated with the May 2024 Storm Events and Hurricane Beryl) are expected to be used for investment in infrastructure. These capital expenditures are anticipated to enhance reliability and safety, increase resiliency and expand our systems through value-added projects. Substantial capital expenditures are also expected for restoration costs associated with Hurricane Beryl, as further described below. In addition to dividend payments on CenterPoint Energy's Common Stock and interest payments on debt, the Registrants' principal anticipated cash requirements for 2025 include the following:

	CenterPoint Energy	Houston Electric	CERC
		(in millions)	
Estimated capital expenditures (1)	$ 4,802	$ 2,560	$ 1,391
Estimated restoration costs associated with May 2024 Storm Events (2)	34	34	—
Estimated restoration costs associated with Hurricane Beryl (2)	102	102	—
Scheduled principal payments on Securitization Bonds	13	—	—
Expected contributions to pension plans and other postretirement plans	120	1	5

(1) Excludes expenditures for the restoration costs associated with the May 2024 Storm Events and Hurricane Beryl.
(2) Represents cash requirements associated with estimated storm restoration costs for 2025.

The Registrants expect that anticipated cash needs for 2025 will be met with borrowings under their credit facilities, proceeds from the issuance of long-term debt, including the issuance of non-recourse securitization bonds at Houston Electric related to costs incurred during the year ended December 31, 2024 due to the May 2024 Storm Events and Hurricane Beryl, anticipated cash flows from operations, and, with respect to CenterPoint Energy and CERC, proceeds from commercial paper and the sale of the Louisiana and Mississippi natural gas LDC businesses, if and when completed (the transaction is expected to close in the first quarter of 2025). Issuances of debt securities in the capital markets, funds raised in the commercial paper markets, term loans and additional credit facilities may not, however, be available on acceptable terms. The Registrants may, from time to time, redeem, repurchase or otherwise acquire their outstanding debt securities through open market purchases, tender offers or pursuant to the terms of such securities.

For more information regarding the May 2024 Storm Events and Hurricane Beryl, see Notes 7, 12 and 14 to the consolidated financial statements as well as "Risk Factors" in Part I, Item 1A of this report.

The following table sets forth the Registrants' estimates of the Registrants' capital expenditures currently planned for projects for 2025 through 2029. See Note 16 to the consolidated financial statements for CenterPoint Energy's actual capital expenditures by reportable segment for 2024.

	2025	2026	2027	2028	2029
CenterPoint Energy			(in millions)		
Electric	$ 3,306	$ 4,358	$ 4,266	$ 4,106	$ 2,728
Natural Gas	1,465	1,604	1,469	1,344	1,327
Corporate and Other	31	20	20	20	20
Total	$ 4,802	$ 5,982	$ 5,755	$ 5,470	$ 4,075
Houston Electric (1)	$ 2,560	$ 3,432	$ 4,008	$ 3,904	$ 2,546
CERC (1)	$ 1,391	$ 1,486	$ 1,391	$ 1,271	$ 1,254

(1) Houston Electric and CERC each consist of a single reportable segment.

Capital Expenditures for Climate-Related Projects. As part of its approximately $47.5 billion 10-year capital expenditure plan, which concludes in 2030, CenterPoint Energy anticipates spending over $3 billion in lower-emissions energy investments and enablement, which may be used to support, among other things, renewable energy generation.

The following table summarizes the Registrants' material current and long-term cash requirements as of December 31, 2024:

	2025	2026	2027	2028	2029	Thereafter	Total
				(in millions)			
CenterPoint Energy							
Securitization Bonds (1)	$ 13	$ 14	$ 14	$ 15	$ 16	$ 252	$ 324
Other long-term debt (1) (2)	51	2,260	1,306	2,048	919	13,738	20,322
Interest payments — Securitization Bonds (3)	16	16	15	14	13	85	159
Interest payments — other long-term debt (3)	967	937	852	771	671	7,596	11,794
Short-term borrowings	500	—	—	—	—	—	500
Commodity and other commitments (4)	805	822	664	578	555	3,059	6,483
Total cash requirements	$ 2,352	$ 4,049	$ 2,851	$ 3,426	$ 2,174	$ 24,730	$ 39,582
Houston Electric							
Other long-term debt (1)	$ —	300	$ 300	$ 500	$ —	$ 7,313	$ 8,413
Interest payments — other long-term debt (3)	378	351	339	335	309	3,809	5,521
Short-term borrowings	500	—	—	—	—	—	500
Total cash requirements	$ 878	$ 651	$ 639	$ 835	$ 309	$ 11,122	$ 14,434
CERC							
Long-term debt (1)	$ 10	$ 60	$ 625	$ 1,230	$ 30	$ 3,260	$ 5,215
Interest payments — long-term debt (3)	251	250	246	188	156	1,071	2,162
Commodity and other commitments (4)	631	597	513	470	456	1,544	4,211
Total cash requirements	$ 892	$ 907	$ 1,384	$ 1,888	$ 642	$ 5,875	$ 11,588

(1) Balances reflect aggregate principal amounts outstanding and do not include unamortized discounts, premiums or issuance costs. See Note 12 to the consolidated financial statements for additional information.

(2) ZENS obligations are included in the 2029 column at their contingent principal amount of $9 million as of December 31, 2024. These obligations are exchangeable for cash at any time at the option of the holders for 95% of the current value of the reference shares attributable to each ZENS ($558 million as of December 31, 2024), as discussed in Note 10 to the consolidated financial statements.

(3) The Registrants calculated estimated interest payments for long-term debt as follows: for fixed-rate debt and term debt, the Registrants calculated interest based on the applicable rates and payment dates; for variable-rate debt and/or non-term debt, the Registrants used interest rates in place as of December 31, 2024. The Registrants typically expect to settle such interest payments with cash flows from operations and short-term borrowings.

(4) For a discussion of commodity and other commitments, see Note 14(a) to the consolidated financial statements.

The table above does not include the following:

- estimated future payments for expected future AROs primarily estimated to be incurred after 2029. See Note 3(c) to the consolidated financial statements for further information.
- expected contributions to pension plans and other postretirement plans in 2025. See Note 8(g) to the consolidated financial statements for further information.
- operating leases. See Note 19 to the consolidated financial statements for further information.

Off-Balance Sheet Arrangements

Other than Houston Electric's general mortgage bonds issued as collateral for tax-exempt long-term debt of CenterPoint Energy as discussed in Note 12 and guarantees as discussed in Note 14(c) to the consolidated financial statements) and short-term leases, the Registrants have no off-balance sheet arrangements.

Regulatory Matters

Houston Electric TEEEF

For information about Houston Electric's TEEEF, see Note 7 to the consolidated financial statements.

Hurricane Beryl

For information about Hurricane Beryl, see Note 7 to the consolidated financial statements.

May 2024 Storm Events

For information about May 2024 Storm Events, see Note 7 to the consolidated financial statements.

February 2021 Winter Storm Event

For information about the February 2021 Winter Storm Event, see Note 7 to the consolidated financial statements.

Indiana Electric Securitization of Generation Retirements (CenterPoint Energy)

For further information about the issuance of SIGECO Securitization Bonds, see Note 7 to the consolidated financial statements.

Indiana Electric CPCN (CenterPoint Energy)

BTAs

On February 23, 2021, Indiana Electric filed a CPCN with the IURC seeking approval to purchase the Posey Solar project. On October 27, 2021, the IURC issued an order approving the CPCN, authorizing Indiana Electric to purchase the Posey Solar project through a BTA to acquire its solar array assets for a fixed purchase price and approved recovery of costs via a levelized rate over the anticipated 35-year life. Due to community feedback and rising project costs caused by inflation and supply chain issues affecting the energy industry, Indiana Electric, along with Arevon, the developer, announced plans in January 2022 to downsize the Posey Solar project to 191 MW. Indiana Electric collaboratively agreed to the scope change, and on February 1, 2023, Indiana Electric entered into an amended and restated BTA that was contingent on further IURC review and approval. On February 7, 2023, Indiana Electric filed a CPCN with the IURC to approve the amended BTA. With the passage of the IRA, Indiana Electric can now pursue PTCs for solar projects. Indiana Electric requested that project costs, net of PTCs, be recovered in rate base rather than a levelized rate, through base rates or the CECA mechanism, depending on which provides more timely recovery. On September 6, 2023, the IURC issued an order approving the CPCN. The Posey Solar project is expected to be placed in service in the second quarter of 2025 and recovered through base rates.

On July 5, 2022, Indiana Electric entered into a BTA to acquire a 130 MW solar array in Pike County, Indiana through a special purpose entity for a capped purchase price. A CPCN for the project was filed with the IURC on July 29, 2022. On September 21, 2022, an agreement in principle was reached resolving all the issues between Indiana Electric and OUCC. The Stipulation and Settlement agreement was filed on October 6, 2022 and a settlement hearing was held on November 1, 2022. On January 11, 2023, the IURC issued an order approving the settlement agreement authorizing Indiana Electric to purchase and acquire the Pike County Solar project through a BTA and approved the estimated cost. The IURC also designated the

project as a clean energy project under applicable Indiana regulations, approved the proposed levelized rate and associated ratemaking and accounting treatment. Due to inflationary pressures, the developer disclosed that costs exceeded the agreed upon levels in the BTA. After negotiations, Indiana Electric and the developer were not able to agree upon updated pricing. As a result, on March 15, 2024, Indiana Electric provided notice to the IURC that it was exercising its right to terminate the BTA, which terminated all further obligations of Indiana Electric with respect to the project.

On January 10, 2023, Indiana Electric filed a CPCN with the IURC to acquire a wind energy generating facility with installed capacity of 200 MWs through a BTA, consistent with its 2019/2020 IRP that calls for up to 300 MWs of wind generation. The wind project is located in MISO's Central Region. Indiana Electric received approval from the IURC to recover the costs of the wind facility via the CECA mechanism, which the developer believes can be placed in service by the end of 2026. On June 6, 2023, the IURC issued an order approving the CPCN, thereby authorizing Indiana Electric to purchase the wind generating facility. However, as of the date of the filing of this Form 10-K, Indiana Electric has not entered into any definitive agreement relating to this wind energy generating facility, and it is not certain that a definitive agreement will be entered into at all.

PPAs

Indiana Electric also sought approval in February 2021 for a 100 MW solar PPA with Clenera, LLC in Warrick County, Indiana. The request accounted for increased cost of debt related to this PPA, which provides equivalent equity return to offset imputed debt during the 25-year life of the PPA. In October 2021, the IURC approved the Warrick County solar PPA but denied the request to preemptively offset imputed debt in the PPA cost. Due to rising project costs caused by inflation and supply chain issues affecting the energy industry, Clenera, LLC and Indiana Electric were compelled to renegotiate terms of the agreement to increase the PPA price. On January 17, 2023, Indiana Electric filed a request with the IURC to amend the previously approved PPA with certain modifications. Revised purchase power costs are requested to be recovered through the fuel adjustment clause proceedings over the term of the amended PPA. On May 30, 2023, the IURC approved the Warrick County solar amended PPA; however, due to MISO interconnection study delays, the developer disclosed the project in-service date would be delayed to 2026.

On August 25, 2021, Indiana Electric filed with the IURC seeking approval to purchase 185 MW of solar power, under a 15-year PPA, from Oriden, which is developing a solar project in Vermillion County, Indiana, and 150 MW of solar power, under a 20-year PPA, from Origis, which is developing a solar project in Knox County, Indiana. On May 4, 2022, the IURC issued an order approving Indiana Electric to enter into both PPAs. In March 2022, when the results of the MISO interconnection study were completed, Origis advised Indiana Electric that the costs to construct the solar project in Knox County, Indiana had increased. The increase was largely driven by escalating commodity and supply chain costs impacting manufacturers worldwide. In August 2022, Indiana Electric and Origis entered into an amended PPA, which reiterated the terms contained in the previously approved Knox County solar PPA with certain modifications. On February 22, 2023, the IURC approved the Knox County solar amended PPA; however, due to MISO interconnection delays, the project in-service date will be delayed to 2026. On January 17, 2023, Indiana Electric filed a request with the IURC to amend the previously approved Vermillion County solar PPA with Oriden with certain modifications. Revised purchase power costs were approved to be recovered through the fuel adjustment clause proceedings over the term of the amended PPA with Oriden. On May 30, 2023, the IURC approved the Vermillion County solar amended PPA; however, due to MISO interconnection study delays, the developer disclosed the project in-service date would be delayed to 2026.

On May 1, 2024, Indiana Electric filed with the IURC seeking approval to purchase 147 MW of wind power under a 25-year PPA with an affiliate of NextEra Energy, Inc., which is developing a wind project in Knox County, Illinois. On November 6, 2024, the IURC approved the Knox County wind PPA, which provided for the recovery of the purchase power costs through the fuel adjustment clause proceedings over the term of the PPA. The facility is targeted to be in operation in early 2026.

Natural Gas Combustion Turbines

On June 17, 2021, Indiana Electric filed a CPCN with the IURC seeking approval to construct two natural gas combustion turbines to replace portions of its existing coal-fired generation fleet. On June 28, 2022, the IURC approved the CPCN. The estimated $334 million turbine facility is being constructed at the previous site of the A.B. Brown power plant in Posey County, Indiana and is expected to provide a combined output of 460 MW. Indiana Electric received approval for depreciation expense and post in-service carrying costs to be deferred in a regulatory asset until the date Indiana Electric's base rates include a return on and recovery of depreciation expense on the facility. A new approximately 23.5 mile pipeline will be constructed and operated by Texas Gas Transmission, LLC to supply natural gas to the turbine facility. FERC granted a certificate to construct the pipeline on October 20, 2022. On January 7, 2025, the United States Court of Appeals for the D.C. Circuit affirmed the

FERC's order granting the certificate. Indiana Electric granted its contractor a full notice to proceed to construct the turbines on December 9, 2022. The facility is targeted to be operational by mid-year 2025. On February 6, 2025, the EPC contractor for Indiana Electric's proposed natural gas combustion turbines provided a notice to Indiana Electric that the EPC contractor was identifying the impacts of the proposed tariffs on the project and intended to seek an equitable adjustment to the contract price for the project. Recovery of the proposed natural gas combustion turbines and regulatory asset was included in the forecasted test year in the Indiana Electric rate case, which was filed with the IURC on December 5, 2023. For more information on the Indiana Electric rate case, see "— Rate Change Applications" below.

For more information regarding uncertainties related to our solar projects, see Part I, Item 1A of this combined Form 10-K and " —Solar Panel Issues" below.

Culley Unit 3 Operations

In June 2022, F.B. Culley Unit 3, an Indiana Electric coal-fired electric generation unit with an installed generating capacity of 270 MW, experienced an operating issue relating to its boiler feed pump turbine. The unit returned to service in March 2023. In testimony filed September 13, 2023, the OUCC and an intervenor that represents industrial customers filed testimony with the IURC alleging that Indiana Electric did not act prudently which led to the unplanned outage and recommended disallowances between $21 million to $27 million. On July 3, 2024, the IURC issued an order finding Indiana Electric acted reasonably and prudently with respect to the events that gave rise to the Culley Unit 3 outage and, in addition, did not approve the intervenors proposed disallowance. The order is now final and non-appealable.

Space City Solar Transmission Interconnection Project (CenterPoint Energy and Houston Electric)

On December 17, 2020, Houston Electric filed a CCN with the PUCT for approval to build a 345 kV transmission line in Wharton County, Texas connecting the Hillje substation on Houston Electric's transmission system to the planned 610 MW Space City Solar Generation facility being developed by third-party developer EDF Renewables. In November 2021, the PUCT approved a route that was estimated to cost $25 million and issued a final order on January 12, 2022. There have been project delays due to supply chain constraints in the developer acquiring solar panels. Houston Electric substantially completed construction in the fall of 2023, and the transmission line is expected to be energized shortly after the generation facility is complete, which is anticipated to occur in the first half of 2026.

Kilgore Transmission Project (CenterPoint Energy and Houston Electric)

On August 30, 2023, Houston Electric filed a CCN application with the PUCT for approval to build a 138 kV double circuit transmission line in Chambers County, Texas that will loop the existing 138 kV Chevron to Langston circuit number 86 on Houston Electric's transmission system to Houston Electric's planned Kilgore substation. On March 7, the PUCT issued a final order approving a route that was estimated to cost $60 million, including substation costs. The actual capital costs of the project, including the transmission line and the planned Kilgore substation, will depend on actual land acquisition costs, construction costs, and other factors. Completion of construction and energization of the line and substation is anticipated to occur in the second quarter of 2026.

Mill Creek Transmission Project (CenterPoint Energy and Houston Electric)

On November 17, 2023, Houston Electric filed a CCN application with the PUCT for approval to build a 138 kV double circuit transmission line in Harris and Montgomery Counties, Texas that will connect Houston Electric's transmission system to Houston Electric's planned Mill Creek substation. On November 21, 2024, the PUCT issued a final order approving a route estimated to cost $68 million. The actual capital costs of the project will depend on actual land acquisition costs, construction costs, and other factors. Completion of construction and energization of the line and substation is anticipated to occur in the first half of 2027.

Texas Legislation (CenterPoint Energy, Houston Electric and CERC)

Houston Electric and CERC were affected by legislation passed in 2023 and associated PUCT rulemaking projects, including the following pieces of legislation that became law during the 88th Texas Legislature, including:

- House Bill 1500 became effective on September 1, 2023 and continues the functions of the PUCT, the Office of Public Utility Counsel, and ERCOT through 2029. This bill also includes an amendment that clarifies the use cases under which TDUs may lease and operate temporary generation during "significant" power outages;

- House Bill 2263 became effective on June 12, 2023 and authorizes LDCs to offer programs to promote energy conservation and to recover costs prudently incurred to implement such programs under Railroad Commission authority;
- House Bill 2555 became effective on June 13, 2023 and allows an electric utility to file a transmission and distribution system resiliency plan with the PUCT and associated cost recovery to enhance its system through hardening, modernization, undergrounding certain lines, lightning mitigation measures, flood mitigation measures, information technology, cybersecurity, physical security, vegetation management and wildfire mitigation. On January 18, 2024, the PUCT issued an Order adopting its Resiliency Plan Rule (16 Tex. Admin. Code § 25.62);
- Senate Bill 947 became effective on September 1, 2023 and creates severe criminal offenses for intentional damage to critical infrastructure facilities that create extended power outages;
- Senate Bill 1015 became effective on June 18, 2023 and allows utilities to file the DCRF twice a year, on any day the PUCT is open (at least 185 days after filing a full base rate proceeding) and setting an administrative approval timeline of 60 days;
- Senate Bill 1016 became effective on May 5, 2023 and requires the PUCT to presume that all employee compensation and benefits are reasonable and necessary when establishing a utility's rates if based upon market compensation studies issued within the last three years; it includes exceptions for utility officer incentives that are based on financial metrics. Certain incentive compensation that is in-line with market studies will be presumed reasonable and recoverable; and
- Senate Bill 1076 became effective on June 2, 2023 and moves the timeline for the PUCT to approve CCN for transmission projects to 180 days after the date of filing, rather than the first anniversary of the day it was filed.

The Registrants will monitor the 89th Texas Legislature for legislation that may impact their businesses.

Minnesota Legislation (CenterPoint Energy and CERC)

The Natural Gas Innovation Act was passed by the Minnesota legislature in June 2021 with bipartisan support. This law establishes a regulatory framework to enable the state's investor-owned natural gas utilities to provide customers with access to renewable energy resources and innovative technologies, with the goal of reducing GHG emissions and advancing the state's clean energy future. The maximum allowable cost for an innovation plan will start at 1.75% of the utility's revenue in the state and could increase to 4% by 2033, subject to review and approval by the MPUC. Specifically, the Natural Gas Innovation Act allows a natural gas utility to submit an innovation plan for approval by the MPUC that can propose the use of renewable energy resources and innovative technologies such as:

- renewable natural gas (produces energy from organic materials such as wastewater, agricultural manure, food waste, agricultural or forest waste);
- renewable hydrogen gas (produces energy from water through electrolysis with renewable electricity such as solar);
- energy efficiency measures (avoids energy consumption in excess of the utility's existing conservation programs); and
- innovative technologies (reduces or avoids GHG emissions using technologies such as carbon capture).

On June 28, 2023, CERC submitted its first innovation plan to the MPUC; the five-year plan includes 18 pilot projects and seven smaller research-and-development projects. These projects will deploy and evaluate a broad array of innovative resources including made-in-Minnesota alternative gases such as renewable natural gas and green hydrogen, as well as pioneering technologies such as a networked geothermal district energy system and end-use carbon capture. The proposed plan requires approval from the MPUC through a review process that is expected to take about one year. The MPUC requested comments by September 15, 2023 if parties believe that the filing is incomplete based on the reporting requirements or if parties do not believe that that the MPUC's standard informal proceeding process is appropriate. No parties filed comments regarding completeness or raising concerns that the MPUC's standard informal procedural process is inappropriate. The initial comment period closed on January 15, 2024, the reply comment period closed on March 15, 2024 and the supplemental comment period closed on May 15, 2024. On July 25, 2024, the MPUC voted to approve the plan with some minor modifications during its agenda meeting and a formal order was issued on October 9, 2024.

Solar Panel Issues (CenterPoint Energy)

CenterPoint Energy's current and future solar projects have been impacted by delays and/or increased costs. The potential delays and inflationary cost pressures communicated from the developers of our solar projects have been primarily due to (i) unavailability of solar panels and other uncertainties related to DOC antidumping and countervailing duties investigation(s), (ii) the December 2021 Uyghur Forced Labor Prevention Act on solar modules and other products manufactured in China's Xinjiang Uyghur Autonomous Region and (iii) persistent general global supply chain and labor availability issues. On May 15, 2024, based on a petition filed by the American Alliance for Solar Manufacturing Trade Committee, the DOC announced the

initiation of antidumping and countervailing duty investigations of silicon photovoltaic cells from Cambodia, Malaysia, Thailand, and Vietnam. On October 1, 2024, the DOC's preliminary countervailing duty determination affirmed the petition and established preliminary duty rates. A final determination is expected in the first quarter of 2025. On November 29, 2024, the DOC announced its preliminary affirmative determination in the antidumping investigation and established preliminary dumping rates. A final determination is expected in the second quarter of 2025. These impacts could result in cost increases for certain projects, and such impacts may require that we seek additional regulatory review and approvals. Additionally, significant changes to project costs and schedules as a result of these factors could impact the viability of the projects. For more information regarding potential delays, cancellations and supply chain disruptions, see "Part I, Item 1A. Risk Factors— Risk Factors Affecting Operations — Electric Generation, Transmission and Distribution — Increases in the cost or..." in this report.

TDSIC 2.0 (CenterPoint Energy)

On May 24, 2023, Indiana Electric filed its petition and case-in-chief with the IURC requesting, among other things, approval of its five-year plan for transmission, distribution, and storage improvements (TDSIC Plan) and an order approving the TDSIC Plan was issued on December 27, 2023. The approved five-year TDSIC Plan, covering the period January 1, 2024 through December 31, 2028, consists of approximately $454 million in proposed investments across seven different programs: (1) Distribution 12kV Circuit Rebuild, (2) Distribution Underground Rebuild, (3) Distribution Automation, (4) Wood Pole Replacement, (5) Transmission Line Rebuild, (6) Substation Rebuild, and (7) Substation Physical Security.

Transmission and Distribution System Resiliency Plans (CenterPoint Energy and Houston Electric)

House Bill 2555, codified as Tex. Util. Code § 38.078, was passed by the 88th Texas Legislature in 2023 and allows an electric utility to file a transmission and distribution system resiliency plan with the PUCT to enhance the resiliency of the utility's transmission system through at least one or more of the following measures: hardening, modernization, undergrounding certain lines, lightning mitigation measures, flood mitigation measures, information technology, cybersecurity measures, physical security measures, vegetation management, and wildfire mitigation and response. House Bill 2555 also allows an electric utility to establish a regulatory asset for distribution-related costs, including depreciation expense and carrying costs at the electric utility's weighted average cost of capital, relating to the implementation of a transmission and distribution system resiliency plan.

On April 29, 2024, Houston Electric filed its first transmission and distribution system resiliency plan with the PUCT, which proposed to implement 25 resiliency measures over a three-year period. On August 1, 2024, Houston Electric announced that it was withdrawing its application for approval of its transmission and distribution system resiliency plan in order to focus on addressing the impacts of Hurricane Beryl and accelerating preparedness and resiliency efforts for the remaining storm season. The ALJ granted Houston Electric's request for withdrawal of the transmission and distribution system resiliency plan on August 16, 2024. Following feedback from customers, external experts and other stakeholders, including elected officials and local agencies, Houston Electric filed the SRP with the PUCT on January 31, 2025 for review and approval. Anticipated to benefit Houston Electric customers by saving approximately 1.3 billion customer minutes of interruption, the SRP proposes to invest approximately $5.75 billion over a three-year period from 2026 to 2028 for transmission and distribution infrastructure, information technology and cybersecurity assets and event response capability. This plan proposes 39 resiliency-enhancing measures and a microgrid pilot program to be implemented over the three-year period. The SRP has an estimated capital cost of approximately $5.54 billion and an estimated operations and maintenance expense of approximately $211 million. Approximately $2.17 billion of such cost is for transmission-related investments, and approximately $3.58 billion is for distribution-related investments.

Rate Change Applications

The Registrants are routinely involved in rate change applications before state regulatory authorities. Those applications include general rate cases, where the entire cost of service of the utility is assessed and reset. In addition, the Registrants are periodically involved in proceedings to adjust their capital tracking mechanisms (e.g., CSIA, DCRF, DRR, GRIP, TCOS, ECA, CECA and TDSIC), their cost of service adjustments (e.g., RSP and RRA), their decoupling mechanism (e.g., decoupling and SRC), and their energy efficiency cost trackers (e.g., CIP, DSMA, EECR, EECRF, EEFC and EEFR).

Texas Gas Rate Case. On October 30, 2023, CERC filed an application with the Railroad Commission and municipal regulatory authorities to set new natural gas base rates that would be applied consistently across the approximately 1.9 million customers. The need for a rate change was primarily driven by the continuing investment in the safety and reliability of the natural gas system, including new Intelis natural gas meters that feature an integrated safety shutoff valve, changes to depreciation rates that better reflect the actual life and salvage characteristics of assets, and changes in other costs to serve customers. A settlement agreement was filed on April 23, 2024. The settlement agreement was approved by the Railroad Commission on June 25, 2024 and provides for a $5 million annual increase in current revenues and establishes a 9.80% ROE and a 60.61% equity ratio for future GRIP filings. New rates became effective in December 2024.

Minnesota Gas Rate Case. On November 1, 2023, CERC filed an application with the MPUC requesting an adjustment to delivery charges in 2024 and 2025 for the natural gas business in Minnesota. The requested increase is approximately 6.5% or $85 million for 2024 and an additional approximately 3.7% or $52 million for 2025. The need for a rate change is primarily driven by the continuing investment in the safety and reliability of the natural gas system, including new Intelis natural gas meters that feature an integrated safety shutoff valve, changes to depreciation rates that better reflect the actual life and salvage characteristics of assets, and changes in other costs to serve customers. The request reflects a proposed 10.3% ROE on a 52.5% equity ratio. Interim rates for 2024 of $69 million, subject to refund, were implemented as of January 1, 2024. A request for interim rates of $33 million for 2025 was filed on September 30, 2024, approved at the December 3, 2024 hearing and approved by an order issued December 20, 2024. A unanimous settlement agreement was filed on November 25, 2024. The settlement provided for an increase of $60.8 million for 2024 and an additional $42.7 million for 2025. The parties agreed to an overall cost of capital of 7.07% for 2024 and 2025. The Administrative Law Judge filed a report on February 13, 2025 recommending the Commission approve the settlement agreement. The anticipated decision date of the rate case is July 1, 2025.

Indiana Electric Rate Case. On December 5, 2023, Indiana Electric filed a petition with the IURC for authority to modify its rates and charges for electric utility service through a phase-in of rates. The requested increase is approximately 16% or $119 million based on a forward looking 2025 test year. The need for a rate increase is primarily driven by the continuing investment in the safety and reliability of the system and normal increases in operating expenses. The initial filing of the rate case reflected a proposed 10.4% ROE on a forecasted 55% equity ratio. Indiana Electric reached a settlement agreement with less than all parties and submitted the agreement to the IURC on May 20, 2024. The settlement reflects a proposed 9.8% ROE on a forecasted 55% equity ratio. The requested increase was lowered to $80 million, an 11% increase. Indiana Electric received a final order on February 3, 2025 approving the settlement with one modification that effectively capped the residential increase to 1.15% of the total increase, allocating the difference to other commercial and industrial customers. The final order approves the 9.8% ROE on a forecasted 55% equity ratio and increases revenues by $80 million.

Houston Electric Rate Case. On March 6, 2024, Houston Electric filed an application with the PUCT requesting authority to change rates and charges for electric transmission and distribution service. The requested increase is approximately $17 million (1%) for retail customers and $43 million (6.6%) for wholesale transmission service, excluding TCRF and rate case expenses. The need for a rate increase is primarily driven by the continuing investment that has been made to support customer growth and to bolster the safety and reliability of Houston Electric's transmission and distribution system. The request reflects a proposed 10.4% ROE and a 45% equity ratio. Errata testimony was filed to correct minor errors included in the initial filing which reduced the requested increase to $56 million compared to current rates. On January 15, 2025, Houston Electric filed a letter indicating that an agreement in principle had been reached with certain parties and that complete settlement documents would be filed as soon as possible. On January 29, 2025, Houston Electric announced that a settlement agreement was reached with certain parties to the rate case filed on March 6, 2024, including the City of Houston and other regional municipalities. Subject to PUCT review and approval, the settlement is expected to result in approximately $50 million less annual revenue and an average decrease of approximately $1 a month for residential customers based on average usage of 1,000 kWh per month. A proposed order was issued on February 10, 2025. The parties must file corrections or exceptions to the proposed order by February 24, 2025.

Ohio Capital Expenditure Program (CEP). On March 1, 2024, CEOH filed an application with the PUCO for authority to modify its CEP rates and charges. The requested increase is approximately $3 million resulting in a proposed CEP rate for residential customers of $1.54 per month. Per the PUCO's Opinion and Order in the 2018 general rate case, the CEP rate is capped at $1.50 per month for residential customers. CEOH requested deferral of the 2023 CEP revenue requirement above the CEP rate cap of approximately $155,000. CEOH filed a statement of resolution on July 30, 2024, indicating CEOH and PUCO staff agree to certain statements including: CEOH's existing deferral authority has not expired and will continue uninterrupted, provided CEOH files its notice of intent for its base rate case prior to the new CEP Rider charges taking effect. PUCO issued a Finding & Order on August 21, 2024, finding that the parties' resolution of the rate cap and deferral authority issues were reasonable. As discussed below, notice of intent for a base rate case was filed the following week.

Ohio Gas Rate Case. On August 27, 2024, CEOH filed a Notice of Intent with PUCO to begin the process of requesting an adjustment in natural gas base rates. CEOH filed its Application and Standard Filing Requirement in October 2024 and the related testimony in November 2024. The filing seeks a revenue requirement increase of approximately $100 million based on a requested return on equity of 10.4% and equity percentage of 45.87%. The need for a rate increase is primarily driven by the continuing investment in the safety and reliability of the natural gas system. A final order is expected no sooner than the first quarter of 2026.

The table below reflects significant applications pending or completed since the Registrants' combined 2023 Form 10-K was filed with the SEC through the date of the filing of this Form 10-K:

Mechanism	Annual Increase (1) (in millions)	Filing Date	Effective Date	Approval Date	Additional Information
CenterPoint Energy and Houston Electric (PUCT)					
DCRF	73	December 2023	April 2024	March 2024	Based on the net change in distribution invested capital since its last base rate proceeding of approximately $2.5 billion for the period January 1, 2019 through September 30, 2023, of which $672 million is incremental to the previous DCRF filing, for an incremental revenue increase of $86 million, adjusted for load growth. On February 5, 2024, Houston Electric notified the ALJ that the parties reached an agreement in principle on all issues in this proceeding and filed an agreed expedited motion for interim rates. On February 13, 2024, interim rates designed to collect $220 million ($73 million incremental) were approved by the ALJ, to be effective April 2024. A final order was issued by the PUCT March 7, 2024.
Rate Case	56	March 2024	TBD	TBD	See discussion above under *Houston Electric Rate Case*.
EECRF	15	May 2024	March 2025	December 2024	The requested $65 million is comprised primarily of the following: 2025 program costs of $50 million; a credit of $0.5 million related to the over-recovery of 2023 program costs; the 2023 earned bonus of $15 million; and 2025 projected evaluation, measurement and verification costs of $0.5 million. On October 17, 2024, a unanimous settlement was filed for an adjusted total of $63 million, keeping the 2023 earned bonus of $15 million. A final order approving the settlement was issued on December 12, 2024.
TCOS	63	November 2024	January 2025	January 2025	Based on net change in invested capital of $517 million for the period July 2023 through September 2024. Notice of Approval was issued by PUCT January 13, 2025.
CenterPoint Energy and CERC - Beaumont/East Texas, South Texas, Houston and Texas Coast (Railroad Commission)					
Rate Case	5	October 2023	December 2024	June 2024	See discussion above under *Texas Gas Rate Case.*
Tax Act Rider	20	August 2024	TBD	TBD	Resulting from the Texas Gas Rate Case, the first Tax Act Rider Calculation was filed on August 1, 2024 pursuant to Docket No. OS-23-00015513 to recover the effects of the Inflation Reduction Act ("Tax Act 2022") and certain other tax-related costs for rates to become effective January 1, 2025. These effects include the return on the CAMT deferred tax asset ("DTA") resulting from the Tax Act 2022, income tax credits resulting from the Tax Act 2022, and the return on the increment or decrement in the NOL DTA included in rate base and in the standard service base revenue requirement approved in the Texas Gas Rate Case. CERC believes its filing is consistent with the Tax Act Rider tariff approved in Docket No. OS-23-00015513. On October 1, 2024, certain parties filed comments disputing the application. Briefings were filed with an ALJ in November 2024. A hearing on the merits will be held on February 21, 2025.
GRIP	71	February 2025	TBD	TBD	Based on net change in invested capital of $446 million.

Mechanism	Annual Increase (1) (in millions)	Filing Date	Effective Date	Approval Date	Additional Information
CenterPoint Energy and CERC - Minnesota (MPUC)					
CIP Financial Incentive	8	May 2024	December 2024	November 2024	CIP Financial Incentive based on 2023 CIP program activity.
Rate Case	136	November 2023	TBD	TBD	See discussion above under *Minnesota Gas Rate Case.*
CenterPoint Energy and CERC - Louisiana (LPSC)					
RSP	12	September /October 2023	June 2024	April 2024	Based on ROE of 9.95% with 50 basis point (+/-) earnings band. The North Louisiana increase, net of TCJA effects considered outside of the earnings band and completion of COVID-19 asset recovery, is $8 million based on a test year ended June 2023 and adjusted ROE of 3.67%. The South Louisiana increase, net of TCJA effects considered outside of the earnings band and completion of COVID-19 asset recovery, is $5 million based on a test year ended June 2023 and adjusted ROE of 5.47%. The TCJA refund impact to North Louisiana and South Louisiana was $0.6 million and $0.4 million, respectively. South Louisiana interim rates were implemented on December 28, 2023, subject to refund. North Louisiana interim rates were implemented on January 29, 2024. Staff reports issued on January 31, 2024 recommended disallowances of $0.3 million and $0.2 million in North and South Louisiana, respectively. LPSC voted to approve the January 2024 staff reports on April 19, 2024. Implementation occurred in June 2024.
RSP	13	October 2024	TBD	TBD	Based on ROE of 9.95% with 50 basis point (+/-) earnings band. The North Louisiana increase, inclusive of TCJA effects considered outside of the earnings band, is $7 million based on a test year ended June 2024 and adjusted ROE of 5.56%. The South Louisiana increase, inclusive of TCJA effects considered outside of the earnings band, is $6 million based on a test year ended June 2024 and adjusted ROE of 5.96%. Interim rates, subject to refund, were implemented December 19, 2024.
CenterPoint Energy and CERC - Mississippi (MPSC)					
RRA	9	May 2024	September 2024	September 2024	Based on ROE of 10.263% with 100 basis points (+/-) earnings band. Revenue increase of approximately $11 million based on 2023 test year adjusted earned ROE of 5.11%. Interim increase of approximately $1.3 million implemented May 31, 2024. On September 5, 2024, MPSC approved a settlement revenue adjustment of $9.4 million.
CenterPoint Energy - Indiana South - Gas (IURC)					
CSIA	4	April 2024	August 2024	July 2024	Requested an increase of $35 million to rate base, which reflects approximately $3.6 million annual increase in current revenues, of which 80% is included in the mechanism and 20% is deferred until the next rate case. The mechanism also includes a change in (over)/under-recovery variance of $0.03 million annually. The final IURC order was issued July 31, 2024, approving CSIA rates as proposed effective August 1, 2024.
CSIA	2	October 2024	February 2025	January 2025	Requested an increase of $18 million to rate base, which reflects approximately $2.4 million annual increase in current revenues, of which 80% is included in the mechanism and 20% is deferred until the next rate case. The mechanism also includes a change in (over)/under-recovery variance of $(1.0) million annually. The final IURC order was issued January 29, 2025 approving rates as filed with the correction filing effective February 1, 2025.

Mechanism	Annual Increase (1) (in millions)	Filing Date	Effective Date	Approval Date	Additional Information
CenterPoint Energy and CERC - Indiana North - Gas (IURC)					
CSIA	9	April 2024	August 2024	July 2024	Requested an increase of $97 million to rate base, which reflects approximately $9.4 million annual increase in current revenues, of which 80% is included in the mechanism and 20% is deferred until the next rate case. The mechanism also includes a change in (over)/under-recovery variance of $1 million annually. The final IURC Order was issued July 31, 2024, approving CSIA rates as proposed effective August 1, 2024.
CSIA	11	October 2024	February 2025	January 2025	Requested an increase of $84 million to rate base, which reflects approximately $11.0 million annual increase in current revenues, of which 80% is included in the mechanism and 20% is deferred until the next rate case. The mechanism also includes a change in (over)/under-recovery variance of $(3.0) million annually. The final IURC order was issued January 29, 2025, approving rates as filed with the correction filing effective February 1, 2025.
CenterPoint Energy and CERC - Ohio - Gas (PUCO)					
CEP	3	March 2024	September 2024	August 2024	See discussion above under *Ohio Capital Expenditure Program.*
DRR	12	May 2024	September 2024	August 2024	Requested an increase of $77 million to rate base for investments made in 2023, which reflects a $12 million annual increase in current revenues. A change in (over)/under-recovery variance of $0.8 million annually is also included in rates. PUCO Opinion & Order was issued August 21, 2024, approving DRR rates as proposed. Revised rates became effective September 1, 2024.
Rate Case	100	October 2024	TBD	TBD	See discussion above under *Ohio Gas Rate Case.*
CenterPoint Energy - Indiana Electric (IURC)					
Rate Case	80	December 2023	February 2025	February 2025	See discussion above under *Indiana Electric Rate Case.*
TDSIC	5	February 2024	May 2024	May 2024	Requested an increase of $36 million to rate base, which reflects a $5 million annual increase in current revenues, of which 80% is included in the mechanism and 20% is deferred until next rate case. An order approving the request was issued on May 17, 2024 and was effective May 16, 2024.
CECA	—	February 2024	May 2024	June 2024	Requested a decrease of $1 million to rate base, which reflects no change in current revenues. The mechanism also includes a change in (over)/under-recovery variance of $0.1 million. The final order was issued May 29, 2024, approving rates effective June 1, 2024.
ECA	6	May 2024	August 2024	August 2024	Requested an increase of $48 million to rate base, which reflects a $6 million annual increase in current revenues, of which 80% is included in the mechanism and 20% is deferred until next rate case. The mechanism also includes a reduction in the under-recovery variance of $1 million. The OUCC filed testimony on July 1, 2024 recommending approval. A final order approving the request was issued on August 28, 2024.
TDSIC	5	August 2024	November 2024	November 2024	Requested an increase of $30 million to rate base, which reflects a $5 million annual increase in current revenues, of which 80% is included in the mechanism and 20% is deferred until the next rate case. The final order was issued on November 27, 2024 approving rates effective November 28, 2024.

(1) Represents proposed increases when effective date and/or approval date is not yet determined. Approved rates could differ materially from proposed rates.

Inflation Reduction Act (IRA)

On August 16, 2022, the IRA was signed into law. The law extends or creates tax-related energy incentives for solar, wind and alternative clean energy sources, implements, subject to certain exceptions, a 1% tax on share repurchases after December 31, 2022, and implements a 15% CAMT based on the adjusted financial statement income of certain large corporations. Corporations are entitled to a CAMT credit to the extent CAMT liability exceeds regular tax liability, which can be carried forward indefinitely and used in future years when regular tax exceeds the CAMT. The Registrants will owe CAMT in excess of their regular tax liability beginning in 2024. As a result, the Registrants may experience a temporary increase in federal cash tax liability due to this provision beginning in 2024. On September 12, 2024, the IRS issued proposed regulations addressing the application of the CAMT. The proposed regulations offer guidance for computing an entity's adjusted financial statement income, in addition to addressing other provisions of the CAMT. At this time, the Company does not anticipate changes to the applicability of CAMT to the Registrants as a result of the proposed regulations. For more information regarding changes in federal income tax laws and regulations and our related risks, see Part I, Item 1A. "Risk Factors — Risk Factors Affecting Regulatory, Environmental and Legal Risks — We may be significantly affected by changes in federal income tax laws and regulations..."

Greenhouse Gas Regulation and Compliance (CenterPoint Energy)

CenterPoint Energy's and CERC's revenues, operating costs and capital requirements could be adversely affected as a result of any regulatory action that would require installation of new control technologies or a modification of their operations or would have the effect of reducing the consumption of natural gas. Additionally, the Methane Emissions Reduction Program established by the IRA and the new regulations published by the EPA on March 8, 2024 targeting reductions in methane emissions, may increase costs related to production, transmission and storage of natural gas. Houston Electric, in contrast to some electric utilities including Indiana Electric, does not generate electricity, other than TEEEF, and thus is not directly exposed to the risk of high capital costs and regulatory uncertainties that face electric utilities that burn fossil fuels to generate electricity. Nevertheless, Houston Electric's and Indiana Electric's revenues could be adversely affected to the extent any resulting regulatory action has the effect of reducing consumption of electricity by ultimate consumers within their respective service territories. Likewise, incentives to conserve energy or to use energy sources other than natural gas could result in a decrease in demand for the Registrants' services. Further, requirements and/or incentives to reduce energy consumption by certain specified dates in the Registrants' respective service areas could have a significant impact on CenterPoint Energy and its operations. Further, our third-party suppliers, vendors and partners may also be impacted by climate change laws and regulations, which could impact CenterPoint Energy's business by, among other things, causing permitting and construction delays, project cancellations or increased project costs passed on to CenterPoint Energy. Conversely, regulatory actions that effectively promote the consumption of natural gas because of its lower emissions characteristics would be expected to benefit CenterPoint Energy and CERC and their natural gas-related businesses. At this time, however, we cannot quantify the magnitude of the impacts from possible new regulatory actions related to GHG emissions, either positive or negative, on the Registrants' businesses. Additionally, the Registrants continue to evaluate the impact of the final rules adopted by the SEC on March 6, 2024 regarding disclosure of certain climate-related information in registration statements and annual reports, for which implementation is subject to ongoing voluntary delay by the SEC, on their respective consolidated financial statements and related disclosures.

Compliance costs and other effects associated with climate change, reductions in GHG emissions and obtaining renewable energy sources remain uncertain; nevertheless, any new regulation or legislation relating to climate change will likely result in an increase in compliance costs. CenterPoint Energy will continue to monitor regulatory activity regarding GHG emission standards that may affect its business. Currently, CenterPoint Energy does not purchase carbon credits. In connection with its net zero emissions goals, CenterPoint Energy is expected to purchase carbon credits in the future; however, CenterPoint Energy does not currently expect the number of credits, or cost for those credits, to be material. For more information on greenhouse gas and climate-change regulation and compliance, see "Business—Environmental Matters" in Item 1 of Part I of this report.

Climate Change Trends and Uncertainties

As a result of increased attention regarding climate change, coupled with adverse economic conditions, availability of alternative energy sources, including private solar, microturbines, fuel cells, energy-efficient buildings and energy storage devices, and new regulations restricting emissions, including potential regulations of methane emissions, some consumers and companies may use less energy, meet their own energy needs through alternative energy sources or avoid expansions of their facilities, including natural gas facilities, resulting in less demand for the Registrants' services. As these technologies likely become more cost-competitive option over time, whether through cost effectiveness or government incentives and subsidies, certain customers may choose to meet their own energy needs and subsequently decrease usage of the Registrants' systems and

services, which may result in, among other things, Indiana Electric's generating facilities becoming less competitive and economical. Further, evolving investor sentiment related to the use of fossil fuels and initiatives to restrict continued production of fossil fuels have had significant impacts on CenterPoint Energy's electric generation and natural gas businesses. For example, because Indiana Electric currently relies on coal for a portion of its generation capacity, certain financial institutions choose not to participate in CenterPoint Energy's financing arrangements. Conversely, demand for the Registrants' services may increase as a result of customer changes in response to climate change. For example, the expected expansion of energy export facilities, including hydrogen facilities, and electrification of industrial processes and transport and logistics, among others, in our service territories could lead to an increase in demand for electricity, resulting in increased usage of CenterPoint Energy's systems and services. Any negative opinions with respect to CenterPoint Energy's environmental practices or its ability to meet the challenges posed by climate change formed by regulators, customers, investors, legislators or other stakeholders could harm its reputation.

To address these developments, CenterPoint Energy announced its net zero emission goals for Scope 1 and certain Scope 2 emissions by 2035 and a 20-30% reduction in certain Scope 3 emissions by 2035 as compared to 2021 levels. Indiana Electric's 2019/2020 IRP identified a preferred portfolio that retires 730 MW of coal-fired generation facilities and replaces these resources with a mix of generating resources composed primarily of renewables, including solar, wind, and solar with storage, supported by dispatchable natural gas combustion turbines including a pipeline to serve such natural gas generation. Indiana Electric continues to execute on its 2019/2020 IRP and has received initial approvals for 626 MWs of the 700-1,000 MWs of solar generation and 200 MWs of the 300 MWs of wind generation identified within Indiana Electric's 2019/2020 IRP through a combination of BTAs and PPAs. Additionally, as reflected in its 10-year capital plan announced in September 2021, CenterPoint Energy anticipates spending over $3 billion in cleaner energy investments and enablement, which may be used to support, among other things, renewable energy generation. CenterPoint Energy believes its planned investments in renewable energy generation and corresponding planned reduction in its Scope 1 and certain Scope 2 emissions as part of its net zero emissions goals, as well as its planned reduction in Scope 3 emissions by 20-30% by 2035 as compared to 2021 levels, support global efforts to reduce the impacts of climate change. Indiana Electric has conducted a new IRP, which was submitted to the IURC in May 2023, to identify an appropriate generation resource portfolio to satisfy the needs of its customers and comply with environmental regulations. The proposed preferred portfolio is the second evolution to the generation transition plan to move away from coal-fired generation to a more sustainable portfolio of resources. Under the proposed preferred portfolio, Indiana Electric plans to convert its last remaining coal unit to natural gas and to add a significant amount of additional renewable resources through 2033. Indiana Electric has since received approval for 147 MWs of wind generation facilities identified within Indiana Electric's 2022/2023 IRP through a PPA. For more information regarding CenterPoint Energy's net zero and GHG emissions reduction goals and the risks associated with them, see Part I, Item 1A. "Risk Factors — Risk Factors Affecting Regulatory, Environmental and Legal Risks — CenterPoint Energy is subject to operational and financial risks..." For more information on Indiana Electric's IRP and associated risks, see Part I, Item 1A. "Risk Factors — Risk Factors Affecting Regulatory, Environmental and Legal Risks — Indiana Electric's execution of its generation transition plan..."

To the extent climate changes result in warmer temperatures in the Registrants' service territories, financial results from the Registrants' businesses could be adversely impacted. For example, CenterPoint Energy's and CERC's Natural Gas could be adversely affected through lower natural gas sales. On the other hand, warmer temperatures in CenterPoint Energy's and Houston Electric's electric service territory may increase revenues from transmission and distribution and generation through increased demand for electricity used for cooling. Another possible result of climate change is more frequent and more severe weather events, such as hurricanes, tornadoes, floods, microbursts, severe winter weather conditions, including ice storms, wildfires, thunderstorms, high winds, hail, derecho events, or extreme temperatures, including such storms as the February 2021 Winter Storm Event, the May 2024 Storm Events and Hurricane Beryl. Since many of the Registrants' facilities are located along or near the Texas Gulf Coast, increased or more severe weather events could increase costs to repair damaged facilities and restore service to customers. CenterPoint Energy's current 10-year capital plan includes capital expenditures to maintain reliability and safety and increase resiliency of its systems as climate change may result in more frequent significant weather events. Houston Electric does not own or operate any electric generation facilities other than, since September 2021, its operation of TEEEF. Houston Electric transmits and distributes to customers of REPs electric power that the REPs obtain from power generation facilities owned by third parties. To the extent adverse weather conditions affect the Registrants' suppliers, results from their energy delivery businesses may suffer. For example, in Texas, the February 2021 Winter Storm Event caused an electricity generation shortage that was severely disruptive to Houston Electric's service territory and the wholesale generation market and also caused a reduction in available natural gas capacity. Additionally, the May 2024 Storm Events and Hurricane Beryl caused significant damage to Houston Electric's electric delivery system and resulted in electric service interruptions peaking at an estimated 922,000 customers and more than 2.1 million customers, respectively. When the Registrants cannot deliver electricity or natural gas to customers, or customers cannot receive services, the Registrants' financial results can be impacted by lost revenues, and they generally must seek approval from regulators to recover restoration costs. To the extent the Registrants are unable to recover those costs, or if higher rates resulting from recovery of such costs result in reduced demand for services, the Registrants' future financial results may be adversely impacted. Further, as the

intensity and frequency of significant weather events continues, it may impact our ability to secure cost-efficient insurance. For more information regarding risks relating to climate change and other weather and natural disaster impacts, see Part I, Item 1A. "Risk Factors — Risk Factors Affecting Regulatory, Environmental and Legal Risks — Climate change and other weather and natural disaster impacts could..."

Other Matters

Credit Facilities

The Registrants may draw on their respective revolving credit facilities from time to time to provide funds used for general corporate and limited liability company purposes, including to backstop CenterPoint Energy's and CERC's commercial paper programs. The facilities may also be utilized to obtain letters of credit. For further details related to the Registrants' revolving credit facilities, see Note 12 to the consolidated financial statements.

Based on the consolidated debt to capitalization covenant in the Registrants' revolving credit facilities, the Registrants would have been permitted to utilize the full capacity of such revolving credit facilities, which aggregated approximately $4.0 billion as of December 31, 2024.

As of February 10, 2025, the Registrants had the following revolving credit facilities and utilization of such facilities:

		Amount Utilized as of February 10, 2025				
Registrant	Size of Facility	Loans	Letters of Credit	Commercial Paper	Weighted Average Interest Rate	Termination Date
	(in millions)					
CenterPoint Energy	$ 2,400	$ —	$ —	$ 737	4.50%	December 6, 2028
CenterPoint Energy (1)	250	—	—	—	—%	December 6, 2028
Houston Electric	300	—	—	—	—%	December 6, 2028
CERC	1,050	—	—	497	4.51%	December 6, 2028
Total	$ 4,000	$ —	$ —	$ 1,234		

(1) This credit facility was issued by SIGECO.

Borrowings under each of the revolving credit facilities are subject to customary terms and conditions. However, there is no requirement that the borrower makes representations prior to borrowing as to the absence of material adverse changes or litigation that could be expected to have a material adverse effect. Borrowings under each of the revolving credit facilities are subject to acceleration upon the occurrence of events of default that we consider customary. The revolving credit facilities also provide for customary fees, including commitment fees, administrative agent fees, fees in respect of letters of credit and other fees. In each of the revolving credit facilities, the spread to SOFR and the commitment fees fluctuate based on the borrower's credit rating. Each of the Registrant's credit facilities provide for a mechanism to replace SOFR with possible alternative benchmarks upon certain benchmark replacement events. The borrowers are currently in compliance with the various business and financial covenants in the four revolving credit facilities.

Debt Transactions

For detailed information about the Registrants' debt transactions in 2024, see Note 12 to the consolidated financial statements.

Securities Registered with the SEC

On May 17, 2023, the Registrants filed a joint shelf registration statement with the SEC registering indeterminate principal amounts of Houston Electric's general mortgage bonds, CERC Corp.'s senior debt securities and CenterPoint Energy's senior debt securities and junior subordinated debt securities and an indeterminate number of shares of Common Stock, shares of preferred stock, depositary shares, as well as stock purchase contracts and equity units. The joint shelf registration statement will expire on May 17, 2026. For information related to the Registrants' debt issuances in 2024, see Note 12 to the consolidated financial statements.

Temporary Investments

As of February 10, 2025, the Registrants had no temporary investments.

Money Pool

The Registrants participate in a money pool through which they and certain of their subsidiaries can borrow or invest on a short-term basis. Funding needs are aggregated and external borrowing or investing is based on the net cash position. The net funding requirements of the CenterPoint Energy money pool are expected to be met with borrowings under CenterPoint Energy's revolving credit facility or the sale of CenterPoint Energy's commercial paper. The net funding requirements of the CERC money pool are expected to be met with borrowings under CERC's revolving credit facility or the sale of CERC's commercial paper. The money pool may not provide sufficient funds to meet the Registrants' cash needs.

The table below summarizes CenterPoint Energy money pool activity by Registrant as of February 10, 2025:

	Weighted Average Interest Rate	Houston Electric	CERC
		(in millions)	
Money pool borrowings	4.56%	$ 58	$ —

Impact on Liquidity of a Downgrade in Credit Ratings

The interest rate on borrowings under the Registrants' credit facilities is based on their respective credit ratings. As of February 10, 2025, Moody's, S&P and Fitch had assigned the following credit ratings to the borrowers:

		Moody's		S&P		Fitch	
Registrant	Borrower/Instrument	Rating	Outlook (1)	Rating	Outlook (2)	Rating	Outlook (3)
CenterPoint Energy	CenterPoint Energy Senior Unsecured Debt	Baa2	Negative	BBB	Negative	BBB	Negative
CenterPoint Energy	Vectren Corp. Issuer Rating	n/a	Negative	BBB+	Negative	n/a	n/a
CenterPoint Energy	SIGECO Senior Secured Debt	A1	Stable	A	Negative	n/a	n/a
Houston Electric	Houston Electric Senior Secured Debt	A2	Negative	A	Negative	A	Negative
CERC	CERC Corp. Senior Unsecured Debt	A3	Stable	BBB+	Negative	A-	Negative
CERC	Indiana Gas Senior Unsecured Debt	n/a	n/a	BBB+	Negative	n/a	n/a

(1) A Moody's rating outlook is an opinion regarding the likely direction of an issuer's rating over the medium term.
(2) An S&P outlook assesses the potential direction of a long-term credit rating over the intermediate to longer term.
(3) A Fitch rating outlook indicates the direction a rating is likely to move over a one- to two-year period.

The Registrants cannot assure that the ratings set forth above will remain in effect for any given period of time or that one or more of these ratings will not be lowered or withdrawn entirely by a rating agency. The Registrants note that these credit ratings are included for informational purposes and are not recommendations to buy, sell or hold the Registrants' securities and may be revised or withdrawn at any time by the rating agency. Each rating should be evaluated independently of any other rating. Any future reduction or withdrawal of one or more of the Registrants' credit ratings could have a material adverse impact on the Registrants' ability to obtain short- and long-term financing, the cost of such financings and the execution of the Registrants' commercial strategies.

A decline in credit ratings could increase borrowing costs under the Registrants' revolving credit facilities. If the Registrants' credit ratings had been downgraded one notch by S&P and Moody's from the ratings that existed as of December 31, 2024, the impact on the borrowing costs under the four revolving credit facilities would have been insignificant. A decline in credit ratings would also increase the interest rate on long-term debt to be issued in the capital markets and could negatively impact the Registrants' ability to complete capital market transactions and to access the commercial paper market. Additionally, a decline in credit ratings could increase cash collateral requirements and reduce earnings of CenterPoint Energy's and CERC's Natural Gas reportable segments.

Pipeline tariffs and contracts typically provide that if the credit ratings of a shipper or the shipper's guarantor drop below a threshold level, which is generally investment grade ratings from both Moody's and S&P, cash or other collateral may be demanded from the shipper in an amount equal to the sum of three months' charges for pipeline services plus the unrecouped cost of any lateral built for such shipper. If the credit ratings of CERC Corp. decline below the applicable threshold levels,

CERC might need to provide cash or other collateral of as much as $159 million as of December 31, 2024. The amount of collateral will depend on seasonal variations in transportation levels.

ZENS and Securities Related to ZENS (CenterPoint Energy)

If CenterPoint Energy's creditworthiness were to drop such that ZENS holders thought CenterPoint Energy's liquidity was adversely affected or the market for the ZENS were to become illiquid, some ZENS holders might decide to exchange their ZENS for cash. Funds for the payment of cash upon exchange could be obtained from the sale of the shares of ZENS-Related Securities that CenterPoint Energy owns or from other sources. CenterPoint Energy owns shares of ZENS-Related Securities equal to approximately 100% of the reference shares used to calculate its obligation to the holders of the ZENS. ZENS exchanges result in a cash outflow because tax deferrals related to the ZENS and shares of ZENS-Related Securities would typically cease when ZENS are exchanged or otherwise retired and shares of ZENS-Related Securities are sold. The ultimate tax liability related to the ZENS and ZENS-Related Securities continues to increase by the amount of the tax benefit realized each year, and there could be a significant cash outflow when the taxes are paid as a result of the retirement or exchange of the ZENS. If all ZENS had been exchanged for cash on December 31, 2024, deferred taxes of approximately $802 million would have been payable in 2024. If all the ZENS-Related Securities had been sold on December 31, 2024, capital gains taxes of approximately $84 million would have been payable in 2024 based on 2024 tax rates in effect. For additional information about ZENS, see Note 10 to the consolidated financial statements.

Cross Defaults

Under the Registrants' respective revolving credit facilities and any term loan agreements (in each case, other than SIGECO), a payment default on, or a non-payment default, event or condition that permits acceleration of, any indebtedness for borrowed money and certain other specified types of obligations (including guarantees) exceeding $125 million by the borrower or any of their respective significant subsidiaries will cause a default under such borrower's respective credit facility or term loan agreement. Under SIGECO's revolving credit facility, a payment default on, or a non-payment default, event or condition that permits acceleration of, any indebtedness for borrowed money and certain other specific types of obligations (including guarantees) exceeding $75 million by SIGECO or any of its significant subsidiaries will cause a default under SIGECO's credit facility. A default by CenterPoint Energy would not trigger a default under its subsidiaries' debt instruments or revolving credit facilities.

Possible Acquisitions, Divestitures and Joint Ventures

From time to time, the Registrants consider the acquisition or the disposition of assets or businesses or possible joint ventures, strategic initiatives or other joint ownership arrangements with respect to assets or businesses. Any determination to take action in this regard will be based on market conditions and opportunities existing at the time, and accordingly, the timing, size or success of any efforts and the associated potential capital commitments are unpredictable. The Registrants may seek to fund all or part of any such efforts with proceeds from debt and/or equity issuances. Debt or equity financing may not, however, be available to the Registrants at that time due to a variety of events, including, among others, maintenance of our credit ratings, industry conditions, general economic conditions, market conditions and market perceptions. CenterPoint Energy has increased its planned capital expenditures in its Electric and Natural Gas businesses multiple times over the recent years to support rate base growth and may continue to do so in the future. The Registrants may continue to explore asset sales as a means to efficiently finance a portion of their increased capital expenditures in the future, subject to the considerations listed above. For further information, see Note 4 to the consolidated financial statements.

On February 19, 2024, CenterPoint Energy, through its subsidiary CERC Corp., entered into the LAMS Asset Purchase Agreement to sell its Louisiana and Mississippi natural gas LDC businesses. The transaction is expected to close in the first quarter of 2025. For further information, see Note 4 to the consolidated financial statements.

Collection of Receivables from REPs (CenterPoint Energy and Houston Electric)

Houston Electric's receivables from the distribution of electricity are collected from REPs that supply the electricity Houston Electric distributes to their customers. Before conducting business, a REP must register with the PUCT and must meet certain financial qualifications. Nevertheless, adverse economic conditions, weather events, such as the February 2021 Winter Storm Event, structural problems in the market served by ERCOT or financial difficulties of one or more REPs could impair the ability of these REPs to pay for Houston Electric's services or could cause them to delay such payments. Houston Electric depends on these REPs to remit payments on a timely basis, and any delay or default in payment by REPs could adversely affect Houston Electric's cash flows. In the event of a REP's default, Houston Electric's tariff provides a number of remedies,

including the option for Houston Electric to request that the PUCT suspend or revoke the certification of the REP. Applicable regulatory provisions require that customers be shifted to another REP or a provider of last resort if a REP cannot make timely payments. However, Houston Electric remains at risk for payments related to services provided prior to the shift to the replacement REP or the provider of last resort. If a REP were unable to meet its obligations, it could consider, among various options, restructuring under the bankruptcy laws, in which event such REP might seek to avoid honoring its obligations and claims might be made against Houston Electric involving payments it had received from such REP. If a REP were to file for bankruptcy, Houston Electric may not be successful in recovering accrued receivables owed by such REP that are unpaid as of the date the REP filed for bankruptcy. However, PUCT regulations authorize utilities, such as Houston Electric, to defer bad debts resulting from defaults by REPs for recovery in future rate cases, subject to a review of reasonableness and necessity.

Other Factors that Could Affect Cash Requirements

In addition to the above factors, the Registrants' liquidity and capital resources could also be negatively affected by:

- cash collateral requirements that could exist in connection with certain contracts, including weather hedging arrangements, and natural gas purchases, natural gas price and natural gas storage activities of CenterPoint Energy's and CERC's Natural Gas reportable segment;
- acceleration of payment dates on certain gas supply contracts, under certain circumstances, as a result of increased natural gas prices, and concentration of natural gas suppliers (CenterPoint Energy and CERC);
- increased costs related to the acquisition of natural gas (CenterPoint Energy and CERC);
- increases in interest expense in connection with debt refinancings and borrowings under credit facilities or term loans or the use of alternative sources of financings, including financings due to the May 2024 Storm Events and Hurricane Beryl;
- various legislative or regulatory actions, including such actions in response to the May 2024 Storm Events and Hurricane Beryl;
- incremental collateral, if any, that may be required due to regulation of derivatives (CenterPoint Energy);
- the ability of REPs, including REP affiliates of NRG and Vistra Energy Corp., to satisfy their obligations to CenterPoint Energy and Houston Electric;
- slower customer payments and increased write-offs of receivables due to higher natural gas prices, changing economic conditions, public health threats or severe weather events, such as the May 2024 Storm Events and Hurricane Beryl (CenterPoint Energy and CERC);
- the satisfaction of any obligations pursuant to guarantees;
- the outcome of litigation, including litigation related to the February 2021 Winter Storm Event and Hurricane Beryl;
- contributions to pension and postretirement benefit plans;
- recovery of any losses under applicable insurance policies;
- restoration costs and revenue losses resulting from future natural disasters such as hurricanes or other severe weather events and the timing of and amounts sought for recovery of such restoration costs; and
- various other risks identified in "Risk Factors" in Part I, Item 1A of this report.

Certain Contractual Limits on Our Ability to Issue Securities and Borrow Money

Certain provisions in certain note purchase agreements relating to debt issued by CERC have the effect of restricting the amount of secured debt issued by CERC and debt issued by subsidiaries of CERC Corp. Additionally, Houston Electric and SIGECO are limited in the amount of mortgage bonds they can issue by the General Mortgage and SIGECO's mortgage indenture, respectively. For information about the total debt to capitalization financial covenants in the Registrants' and SIGECO's revolving credit facilities, see Note 12 to the consolidated financial statements.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of the Registrants' financial statements in conformity with GAAP requires management to apply appropriate accounting policies and to make estimates and judgments that can have a significant effect on the Registrants' financial condition, results of operations or cash flows. The circumstances that make these judgments difficult, subjective and/or complex have to do with the need to make estimates about the effect of matters that are inherently uncertain. Estimates and assumptions about future events and their effects cannot be predicted with certainty. The Registrants base their estimates on historical experience and on various other assumptions that they believe to be reasonable under the circumstances, the results of which form the basis for making judgments. These estimates may change as new events occur, as more experience is acquired, as additional information is obtained and as the Registrants' operating environment changes. Our management believes the following accounting policies involve the application of critical accounting estimates. Accordingly, these accounting estimates

have been reviewed and discussed with the Audit Committee of CenterPoint Energy's Board of Directors. For a complete discussion of the Registrants' significant accounting policies, see Note 2 to the consolidated financial statements.

Accounting for Rate Regulation

Accounting guidance for regulated operations provides that rate-regulated entities account for and report assets and liabilities consistent with the recovery of those incurred costs in rates if the rates established are designed to recover the costs of providing the regulated service and if the competitive environment makes it probable that such rates can be charged and collected. CenterPoint Energy, for its Electric and Natural Gas reportable segments, Houston Electric and CERC apply this accounting guidance. Certain expenses and revenues subject to utility regulation or rate determination normally reflected in income are deferred on the balance sheet as regulatory assets or liabilities and are recognized in income as the related amounts are included in service rates and recovered from or refunded to customers. Regulatory assets and liabilities are recorded when it is probable that these items will be recovered or reflected in future rates. Determining probability requires significant judgment on the part of management and includes, but is not limited to, consideration of testimony presented in regulatory hearings, proposed regulatory decisions, final regulatory orders and the strength or status of applications for rehearing or state court appeals. If events were to occur that would make the recovery of these assets and liabilities no longer probable, the Registrants would be required to write off or write down these regulatory assets and liabilities. For further detail on the Registrants' regulatory assets and liabilities, see Note 7 to the consolidated financial statements.

Impairment of Long-Lived Assets, Including Goodwill

The Registrants review the carrying value of long-lived assets, including goodwill, whenever events or changes in circumstances indicate that such carrying values may not be recoverable, and at least annually, goodwill is tested for impairment as required by accounting guidance for goodwill. Unforeseen events, changes in market conditions, and probable regulatory disallowances, where applicable, could have a material effect on the value of long-lived assets, including goodwill, future cash flows, interest rate, and regulatory matters, and could result in an impairment charge. The Registrants recorded no impairments to long-lived assets, including goodwill during 2024, 2023 and 2022.

Fair value is the amount at which an asset, liability or business could be bought or sold in a current transaction between willing parties and may be estimated using a number of techniques, including quoted market prices or valuations by third parties, present value techniques based on estimates of cash flows, or multiples of earnings or revenue performance measures. The fair value could be different using different estimates and assumptions in these valuation techniques.

Fair value measurements require significant judgment and unobservable inputs, including (i) projected timing and amount of future cash flows, which factor in planned growth initiatives, (ii) the regulatory environment, as applicable, and (iii) discount rates reflecting risk inherent in the future market prices. Determining the discount rates for the businesses that are not rate-regulated, such as for Energy Systems Group prior to the sale in June 2023, requires the estimation of the appropriate company-specific risk premiums for such businesses based on evaluation of industry and entity-specific risks, which includes expectations about future market or economic conditions existing on the date of the impairment test. Changes in these assumptions could have a significant impact on results of the impairment tests.

Annual Goodwill Impairment Test

CenterPoint Energy and CERC completed their 2024 annual goodwill impairment test during the third quarter of 2024 and determined, based on a qualitative assessment, that no goodwill impairment charge was required for any reporting unit. No qualitative factors were present that indicated impairment of CenterPoint Energy or CERC reporting units.

Although no goodwill impairment resulted from the 2024 annual test, an interim goodwill impairment test could be triggered by the following: actual earnings results that are materially lower than expected, significant adverse changes in the operating environment, an increase in the discount rate, changes in other key assumptions which require judgment and are forward looking in nature, if CenterPoint Energy's market capitalization falls below book value for an extended period of time, or events affecting a reporting unit such as a contemplated disposal of all or part of a reporting unit.

Assets Held for Sale

Generally, a long-lived asset to be sold is classified as held for sale in the period in which management, with approval from the Board of Directors, as applicable, commits to a plan to sell, and a sale is expected to be completed within one year. The Registrants record assets and liabilities held for sale, or the disposal group, at the lower of their carrying value or their estimated fair value less cost to sell. If the disposal group reflects a component of a reporting unit and meets the definition of a business,

the goodwill within that reporting unit is allocated to the disposal group based on the relative fair value of the components representing a business that will be retained and disposed. Goodwill is not allocated to a portion of a reporting unit that does not meet the definition of a business.

As described further in Note 4 to the consolidated financial statements, certain assets and liabilities of the Louisiana and Mississippi natural gas LDC businesses met the held for sale criteria and the goodwill attributable to these businesses as of December 31, 2024 was $217 million and $122 million for CenterPoint Energy and CERC, respectively.

Accounting for Securitization of Coal Generation Facility Retirements

Accounting guidance for rate regulated long-lived asset abandonment requires that the carrying value of an operating asset or an asset under construction is removed from property, plant and equipment when it becomes probable that the asset will be abandoned. The Registrants recognize a loss on abandonment when they conclude it is probable the cost will not be recovered in future rates. When the Registrants conclude it is probable that costs will be recovered in future rates, a regulatory asset is recognized. The portion of property, plant and equipment that will remain used and useful until abandonment and recovered through depreciation expense in rates will continue to be classified as property, plant and equipment until the asset is abandoned. The Registrants evaluate if an adjustment to the estimated life of the asset and, accordingly, the rate of depreciation, is required to recover the asset while it is still providing service. Determining probability of abandonment or probability of recovery requires significant judgment on the part of management and includes, but is not limited to, consideration of testimony presented in regulatory hearings, proposed regulatory decisions, final regulatory orders and the strength or status of applications for rehearing or state court appeals.

In connection with the securitization financing of qualified costs in the second quarter of 2023 associated with the completed retirement of SIGECO's A.B. Brown coal generation facilities, CenterPoint Energy evaluated the VIE consisting of the SIGECO Securitization Subsidiary, a wholly-owned, bankruptcy-remote, special purpose entity, for possible consolidation, including review of qualitative factors such as the power to direct the activities of the VIE and the obligation to absorb losses of the VIE. CenterPoint Energy has the power to direct the significant activities of the VIE and is most closely associated with the VIE as compared to other interests held by the holders of the SIGECO Securitization Bonds. CenterPoint Energy is, therefore, considered the primary beneficiary and consolidated the VIE.

For purposes of reporting cash flows, the Registrants consider cash equivalents to be short-term, highly-liquid investments with maturities of three months or less from the date of purchase. Cash and cash equivalents held by the SIGECO Securitization Subsidiary solely to support servicing the SIGECO Securitization Bonds as of December 31, 2024 are reflected on CenterPoint Energy's Consolidated Balance Sheet.

In connection with the issuance of the SIGECO Securitization Bonds, CenterPoint Energy was required to establish a restricted cash account to collateralize the SIGECO Securitization Bonds that were issued in the financing transaction. The restricted cash account is not available for withdrawal until the maturity of the SIGECO Securitization Bonds and is not included in cash and cash equivalents.

Unbilled Revenues

Revenues related to electricity delivery and natural gas sales and services are generally recognized upon delivery to customers. However, the determination of deliveries to individual customers is based on the reading of their meters, which is performed on a systematic basis throughout the month either electronically through AMS meter communications or manual readings. At the end of each month, deliveries to non-AMS customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is estimated. Information regarding deliveries to AMS customers after the last billing is obtained from actual AMS meter usage data. Unbilled electricity delivery revenue is estimated each month based on actual AMS meter data, daily supply volumes and applicable rates. Unbilled natural gas sales are estimated based on estimated purchased gas volumes, estimated lost and unaccounted for gas and tariffed rates in effect. As additional information becomes available, or actual amounts are determinable, the recorded estimates are revised. Consequently, operating results can be affected by revisions to prior accounting estimates.

Employee Benefit Plans

CenterPoint Energy sponsors pension and other retirement plans in various forms covering all employees who meet eligibility requirements. CenterPoint Energy uses several statistical and other factors that attempt to anticipate future events in calculating the expense and liability related to its plans. These factors include assumptions about the discount rate, expected

return on plan assets and rate of future compensation increases as estimated by management, within certain guidelines. In addition, CenterPoint Energy's actuarial consultants use subjective factors such as withdrawal and mortality rates. The actuarial assumptions used may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates or longer or shorter life spans of participants. These differences may result in a significant impact to the amount of pension and other retirement plans expense recorded. Read "— Other Significant Matters — Pension Plans" for further discussion.

NEW ACCOUNTING PRONOUNCEMENTS

See Note 2(q) to the consolidated financial statements, incorporated herein by reference, for a discussion of new accounting pronouncements that affect the Registrants.

OTHER SIGNIFICANT MATTERS

Pension Plans (CenterPoint Energy). As discussed in Note 8(b) to the consolidated financial statements, CenterPoint Energy maintains non-contributory qualified defined benefit pension plans covering eligible employees. Employer contributions for the qualified plans are based on actuarial computations that establish the minimum contribution required under ERISA and the maximum deductible contribution for income tax purposes.

Under the terms of CenterPoint Energy's pension plans, it reserves the right to change, modify or terminate the plan. CenterPoint Energy's funding policy is to review amounts annually and contribute an amount at least equal to the minimum contribution required under ERISA.

Additionally, CenterPoint Energy maintains unfunded non-qualified benefit restoration plans which allow participants to receive the benefits to which they would have been entitled under the non-contributory qualified pension plan except for federally mandated limits on qualified plan benefits or on the level of compensation on which qualified plan benefits may be calculated.

CenterPoint Energy's funding requirements and employer contributions for the years ended December 31, 2024, 2023 and 2022 were as follows:

	Year Ended December 31,		
	2024	2023	2022
CenterPoint Energy		(in millions)	
Minimum funding requirements for qualified pension plans	$ 23	$ —	$ —
Employer contributions to the qualified pension plans	23	24	27
Employer contributions to the non-qualified pension plans	7	8	8

CenterPoint Energy expects to make contributions of approximately $105 million and $7 million to the qualified and non-qualified pension plans in 2025, respectively.

Changes in pension obligations and plan assets may not be immediately recognized as pension expense in CenterPoint Energy's Statements of Consolidated Income, but generally are recognized in future years over the remaining average service period of plan participants. As such, significant portions of pension expense recorded in any period may not reflect the actual level of benefit payments provided to plan participants.

As the sponsor of a plan, CenterPoint Energy is required to (a) recognize on its Consolidated Balance Sheet an asset for the plan's over-funded status or a liability for the plan's under-funded status, (b) measure a plan's assets and obligations as of the end of the fiscal year and (c) recognize changes in the funded status of the plans in the year that changes occur through adjustments to other comprehensive income and, when related to its rate-regulated utilities with recoverability of cost, to regulatory assets.

The projected benefit obligation for all defined benefit pension plans was $1.5 billion as of December 31, 2024 and 2023, respectively. The impacts resulting from increases in discount rates were offset by the changes in demographic and expected versus actual returns on assets.

As of December 31, 2024, the projected benefit obligation exceeded the market value of plan assets of CenterPoint Energy's pension plans by $345 million. Changes in interest rates or the market values of the securities held by the plan during

a year could materially, positively or negatively, change the funded status and affect the level of pension expense and required contributions at the next remeasurement.

Houston Electric and CERC participate in CenterPoint Energy's qualified and non-qualified pension plans covering substantially all employees. Pension cost by Registrant was as follows for the periods presented:

	Year Ended December 31,								
	2024			2023			2022		
	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC
	(in millions)								
Pension cost	$ 51	$ 23	$ 18	$ 53	$ 27	$ 19	$ 172	$ 59	$ 88

The calculation of pension cost and related liabilities requires the use of assumptions. Changes in these assumptions can result in different expense and liability amounts, and future actual experience can differ from the assumptions. Two of the most critical assumptions are the expected long-term rate of return on plan assets and the assumed discount rate.

As of December 31, 2024, CenterPoint Energy's qualified pension plans had an expected long-term rate of return on plan assets of 7.00%, which is 50 basis points higher than the 6.50% rate assumed as of December 31, 2023. The expected rate of return assumption was developed using the targeted asset allocation of our plans and the expected return for each asset class. CenterPoint Energy regularly reviews its actual asset allocation and periodically rebalances plan assets to reduce volatility and better match plan assets and liabilities.

As of December 31, 2024, the projected benefit obligation was calculated assuming a discount rate of 5.60%, which is 65 basis points higher than the 4.95% discount rate assumed as of December 31, 2023 attributed primarily to rising interest rates. The discount rate was determined by reviewing yields on high-quality bonds that receive one of the two highest ratings given by a recognized rating agency and the expected duration of pension obligations specific to the characteristics of CenterPoint Energy's plans.

CenterPoint Energy's actuarially determined pension and other postemployment cost for 2024 and 2023 that is greater or less than the amounts being recovered through rates in the majority of Texas jurisdictions is deferred as a regulatory asset or liability, respectively. Pension cost for 2025, including the non-qualified benefit restoration plan, is estimated to be $49 million before applicable regulatory deferrals and capitalization, based on an expected return on plan assets of 7.00% and a discount rate of 5.60% as of December 31, 2024. If the expected return assumption were lowered by 50 basis points from 7.00% to 6.50%, the 2025 pension cost would increase by approximately $6 million.

As of December 31, 2024, the pension plans projected benefit obligation, including the unfunded non-qualified pension plans, exceeded plan assets by $345 million. If the discount rate were lowered by 50 basis points from 5.60% to 5.10%, CenterPoint Energy's projected benefit obligation would increase by approximately $60 million and its 2025 pension cost would decrease by approximately $2 million. The expected reduction in pension cost due to the decrease in discount rate is a result of the expected correlation between the reduced interest rate and appreciation of fixed income assets in pension plans with significantly more fixed income instruments than equity instruments. In addition, the assumption change would impact CenterPoint Energy's Consolidated Balance Sheets by increasing the regulatory asset recorded as of December 31, 2024 by $54 million and would result in an incremental charge to comprehensive income in 2024 of $5 million, net of tax of $1 million, due to the increase in the projected benefit obligation.

Future changes in plan asset returns, assumed discount rates and various other factors related to the pension plans will impact CenterPoint Energy's future pension expense and liabilities. CenterPoint Energy cannot predict with certainty what these factors will be in the future.

Item 7A. *Quantitative and Qualitative Disclosures About Market Risk*

Impact of Changes in Interest Rates, Equity Prices and Energy Commodity Prices

The Registrants are exposed to various market risks. These risks arise from transactions entered into in the normal course of business and are inherent in the Registrants' consolidated financial statements. Most of the revenues and income from the Registrants' business activities are affected by market risks. Categories of market risk include exposure to interest rates, equity prices and commodity prices through non-trading activities. A description of each market risk is set forth below:

- Interest rate risk primarily results from exposures to changes in the level of borrowings and changes in interest rates;
- Equity price risk results from exposures to changes in prices of individual equity securities (CenterPoint Energy); and
- Commodity price risk results from exposures to price volatilities of commodities, such as natural gas, NGLs and other energy commodities (CenterPoint Energy).

Management has established comprehensive risk management policies to monitor and manage these market risks.

Interest Rate Risk

As of December 31, 2024, the Registrants had outstanding long-term debt and lease obligations and CenterPoint Energy had obligations under its ZENS that subject them to the risk of loss associated with movements in market interest rates. The Registrants seek to manage interest rate exposure by monitoring the effects of changes in market interest rates and using a combination of fixed and variable rate debt. Additionally, interest rate swaps are used to mitigate interest rate exposure when deemed appropriate. See Note 7 to the Interim Condensed Financial Statements.

CenterPoint Energy's floating rate obligations aggregated $1.5 billion and $1.9 billion as of December 31, 2024 and 2023, respectively. If the floating interest rates were to increase by 100 basis points from December 31, 2024 rates, CenterPoint Energy's combined interest expense would increase by approximately $15 million annually.

Houston Electric's floating rate obligations aggregated $500 million as of December 31, 2024, which mature on December 24, 2025. Houston Electric had no floating rate notes as of December 31, 2023.

CERC's floating rate obligations aggregated $599 million and $484 million as of December 31, 2024 and 2023, respectively. If the floating interest rates were to increase by 100 basis points from December 31, 2024 rates, CERC's combined interest expense would increase by approximately $6 million annually. CERC has no floating rate notes maturing in 2025.

As of December 31, 2024 and 2023, CenterPoint Energy had outstanding fixed-rate debt (excluding indexed debt securities) aggregating $19.7 billion and $16.9 billion, respectively, in principal amount and having a fair value of $18.4 billion and $16.1 billion, respectively. Because these instruments are fixed-rate, they do not expose CenterPoint Energy to the risk of loss in earnings due to changes in market interest rates. However, the fair value of these instruments would increase by approximately $792 million if interest rates were to decline by 10% from their levels as of December 31, 2024.

As of December 31, 2024 and 2023, Houston Electric had outstanding fixed-rate debt aggregating $8.4 billion and $7.7 billion, respectively, in principal amount and having a fair value of approximately $7.3 billion and $7 billion, respectively. Because these instruments are fixed-rate, they do not expose Houston Electric to the risk of loss in earnings due to changes in market interest rates. However, the fair value of these instruments would increase by approximately $398 million if interest rates were to decline by 10% from their levels as of December 31, 2024. Houston Electric has no fixed-rate general mortgage bonds maturing in 2025.

As of December 31, 2024 and 2023, CERC had outstanding fixed-rate debt aggregating $4.6 billion and $4.2 billion, respectively, in principal amount and having a fair value of $4.5 billion and $4.2 billion, respectively. Because these instruments are fixed-rate, they do not expose CERC to the risk of loss in earnings due to changes in market interest rates. However, the fair value of these instruments would increase by approximately $160 million if interest rates were to decline by 10% from their levels at December 31, 2024. CERC has $10 million fixed-rate senior notes maturing in 2025.

In general, such an increase in fair value previously described would impact earnings and cash flows only if the Registrants were to reacquire all or a portion of these instruments in the open market prior to their maturity.

The ZENS obligation is bifurcated into a debt component and a derivative component. The debt component of $2 million at December 31, 2024 was a fixed-rate obligation and, therefore, did not expose CenterPoint Energy to the risk of loss in earnings due to changes in market interest rates. However, the fair value of the debt component would increase by less than $1 million if interest rates were to decline by 10% from levels at December 31, 2024. Changes in the fair value of the derivative component, a $619 million recorded liability at December 31, 2024, are recorded in CenterPoint Energy's Statements of Consolidated Income and, therefore, it is exposed to changes in the fair value of the derivative component as a result of changes in the underlying risk-free interest rate. If the risk-free interest rate were to increase by 10% from December 31, 2024 levels, the fair value of the derivative component liability would decrease by approximately $1 million, which would be recorded as a gain on indexed securities in CenterPoint Energy's Statements of Consolidated Income.

Equity Market Value Risk (CenterPoint Energy)

CenterPoint Energy is exposed to equity market value risk through its ownership of 10.2 million shares of AT&T Common, 0.9 million shares of Charter Common and 2.5 million shares of WBD Common, which CenterPoint Energy holds to facilitate its ability to meet its obligations under the ZENS. See Note 10 to the consolidated financial statements for a discussion of CenterPoint Energy's ZENS obligation. Changes in the fair value of the ZENS-Related Securities held by CenterPoint Energy are expected to substantially offset changes in the fair value of the derivative component of the ZENS. A decrease of 10% from the December 31, 2024 aggregate market value of these shares would result in a net loss of less than $1 million, which would be recorded on a gross basis as both a gain on indexed debt securities and as a loss on equity securities in CenterPoint Energy's Statements of Consolidated Income.

Commodity Price Risk From Non-Trading Activities (CenterPoint Energy and CERC)

CenterPoint Energy's regulated operations are exposed to commodity price risk during severe weather events, such as hurricanes, tornadoes and severe winter weather conditions. Severe weather events can increase commodity prices related to natural gas, coal and purchased power, which may increase our costs of providing service, and those costs may not be recoverable in rates. Recovery of cost increases driven by rising commodity prices during severe weather events could be resisted by our regulators and our regulators might attempt to deny or defer timely recovery of those costs.

However, CenterPoint Energy's and CERC's regulated operations in Indiana have limited exposure to commodity price risk for transactions involving purchases and sales of natural gas, coal and purchased power for the benefit of retail customers due to current state regulations, which, subject to compliance with those regulations, allow for recovery of the cost of such purchases through natural gas and fuel cost adjustment mechanisms. CenterPoint Energy's and CERC's utility natural gas operations in Indiana have regulatory authority to lock in pricing for up to 50% of annual natural gas purchases using arrangements with an original term of up to 10 years. This authority has been utilized to secure fixed price natural gas using both physical purchases and financial derivatives.

Although CenterPoint Energy's and CERC's regulated operations are exposed to limited commodity price risk, natural gas and coal prices have other effects on working capital requirements, interest costs, and some level of price-sensitivity in volumes sold or delivered. Constructive regulatory orders, such as those authorizing lost margin recovery, other innovative rate designs and recovery of unaccounted for natural gas and other natural gas-related expenses, also mitigate the effect natural gas costs may have on CenterPoint Energy's financial condition. In 2008, the PUCO approved an exit of the merchant function in CenterPoint Energy's and CERC's Ohio natural gas service territory, allowing Ohio customers to purchase substantially all natural gas directly from retail marketers rather than from CenterPoint Energy or CERC.

Item 8. ***Financial Statements and Supplementary Data***

Index to Financial Statements

CenterPoint Energy, Inc. and Subsidiaries	
Report of Independent Registered Public Accounting Firm	93
Statements of Consolidated Income	95
Statements of Consolidated Comprehensive Income	96
Consolidated Balance Sheets	97
Statements of Consolidated Cash Flows	99
Statements of Consolidated Changes in Equity	100
CenterPoint Energy Houston Electric, LLC and Subsidiaries	
Report of Independent Registered Public Accounting Firm	101
Statements of Consolidated Income	103
Statements of Consolidated Comprehensive Income	104
Consolidated Balance Sheets	105
Statements of Consolidated Cash Flows	107
Statements of Consolidated Changes in Equity	108
CenterPoint Energy Resources Corp. and Subsidiaries	
Report of Independent Registered Public Accounting Firm	109
Statements of Consolidated Income	111
Statements of Consolidated Comprehensive Income	112
Consolidated Balance Sheets	113
Statements of Consolidated Cash Flows	115
Statements of Consolidated Changes in Equity	116

Combined Notes to Consolidated Financial Statements

(1) Background	117
(2) Summary of Significant Accounting Policies	118
(3) Property, Plant and Equipment	122
(4) Held for Sale and Divestitures	124
(5) Revenue Recognition	126
(6) Goodwill	129
(7) Regulatory Matters	131
(8) Stock-Based Incentive Compensation Plans and Employee Benefit Plans	137
(9) Fair Value Measurements	147
(10) Equity Securities and Indexed Debt Securities (ZENS)	149
(11) Equity	151
(12) Short-term Borrowings and Long-term Debt	154
(13) Income Taxes	160
(14) Commitments and Contingencies	164
(15) Earnings Per Share (CenterPoint Energy)	171
(16) Reportable Segments	172
(17) Supplemental Disclosure of Cash Flow and Balance Sheet	176
(18) Related Party Transactions (Houston electric and CERC)	177
(19) Leases	178
(20) Subsequent Events	181

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and the Board of Directors of CenterPoint Energy, Inc.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of CenterPoint Energy, Inc. and subsidiaries (the "Company") as of December 31, 2024 and 2023, the related consolidated statements of income, comprehensive income, changes in equity, and cash flows, for each of the three years in the period ended December 31, 2024, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2024 and 2023, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2024, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2024, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 20, 2025, expressed an unqualified opinion on the Company's internal control over financial reporting.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current-period audit of the financial statements that was communicated or required to be communicated to the audit committee and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Impact of Rate Regulation on the Financial Statements — Refer to Note 7 to the financial statements

Critical Audit Matter Description

The Company is subject to rate regulation by regulators and commissions in various jurisdictions (collectively, the "Commissions") that have jurisdiction with respect to the rates of electric and gas transmission and distribution companies in those jurisdictions. Management has determined its regulated operations meet the requirements under accounting principles generally accepted in the United States of America to prepare its financial statements applying the specialized rules to account for the effects of cost-based rate regulation. The impacts of accounting for the economics of rate regulation are pervasive to the financial statements and disclosures.

The Company's rates are subject to regulatory rate-setting processes by the Commissions. Rates are determined and approved in regulatory proceedings based on an analysis of the Company's costs to provide utility service and a return on, and recovery of, the Company's investment in the utility business. Regulatory decisions can have an impact on the recovery of costs, the rate of return earned on investment, and the timing and amount of assets to be recovered in rates. The Commissions' regulation of rates is premised on the full recovery of prudently incurred costs and a reasonable rate of return on invested capital. Decisions

to be made by the Commissions in the future will impact the accounting for regulated operations, including decisions about the amount of allowable costs and return on invested capital included in rates and any refunds that may be required. While the Company has indicated it expects to recover costs from customers through regulated rates, there is a risk that the Commissions will not approve: (1) full recovery of the costs of providing utility service, or (2) full recovery of all amounts invested in the utility business and a reasonable return on that investment.

We identified rate regulation as a critical audit matter due to the significant judgments made by management to support its assertions about certain affected account balances and disclosures and the high degree of subjectivity involved in assessing the impact of regulatory actions on the financial statements. Management's judgments include assessing the likelihood of (1) recovery in future rates of incurred costs, (2) a disallowance of capital investments made by the Company and (3) refunds to customers. Given that certain of management's accounting judgments are based on assumptions about the outcome of decisions by the Commissions, auditing these judgments required specialized knowledge of accounting for rate regulation and the rate setting process.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the potential uncertainty of decisions by the Commissions included the following, among others:

- We evaluated the Company's disclosures related to the effects of rate regulation by testing certain recorded balances and evaluating regulatory developments.

- We read relevant regulatory orders issued by the Commissions, regulatory statutes, filings made by the Company and intervenors, and other external information. We evaluated relevant external information and compared it to certain recorded regulatory asset and liability balances for completeness.

- For certain regulatory matters, we inspected the Company's filings with the Commissions and the filings with the Commissions by intervenors to assess the likelihood of recovery in future rates or of a future reduction in rates based on precedents of the Commissions' treatment of similar costs under similar circumstances.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
February 20, 2025

We have served as the Company's auditor since 1932.

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES
STATEMENTS OF CONSOLIDATED INCOME

	Year Ended December 31,		
	2024	2023	2022
	(in millions, except per share amounts)		
Revenues:			
Utility revenues	$ 8,589	$ 8,524	$ 9,018
Non-utility revenues	54	172	303
Total	8,643	8,696	9,321
Expenses:			
Utility natural gas, fuel and purchased power	1,715	2,061	2,887
Non-utility cost of revenues, including natural gas	3	99	204
Operation and maintenance	2,949	2,850	2,833
Depreciation and amortization	1,439	1,401	1,288
Taxes other than income taxes	547	525	543
Total	6,653	6,936	7,755
Operating Income	1,990	1,760	1,566
Other Income (Expense):			
Gain (loss) on equity securities	20	31	(227)
Gain (loss) on indexed debt securities	(14)	(27)	325
Gain (loss) on sale	—	(13)	303
Interest expense and other finance charges	(818)	(684)	(511)
Interest expense on Securitization Bonds	(20)	(17)	(13)
Other income (expense), net	56	37	(26)
Total	(776)	(673)	(149)
Income Before Income Taxes	1,214	1,087	1,417
Income tax expense	195	170	360
Net Income	1,019	917	1,057
Income allocated to preferred shareholders	—	50	49
Income Available to Common Shareholders	$ 1,019	$ 867	$ 1,008
Basic Earnings Per Common Share	$ 1.58	$ 1.37	$ 1.60
Diluted Earnings Per Common Share	$ 1.58	$ 1.37	$ 1.59
Weighted Average Common Shares Outstanding, Basic	643	631	629
Weighted Average Common Shares Outstanding, Diluted	644	633	632

See Combined Notes to Consolidated Financial Statements

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES
STATEMENTS OF CONSOLIDATED COMPREHENSIVE INCOME

	Year Ended December 31,		
	2024	2023	2022
		(in millions)	
Net income	$ 1,019	$ 917	$ 1,057
Other comprehensive income (loss):			
Adjustment to pension and other postemployment plans (net of tax expense (benefit) of $4, ($1) and $2, respectively)	15	(5)	32
Net deferred gain from cash flow hedges (net of tax of $-0-, $-0- and $-0-)	4	1	—
Reclassification of deferred (gain) loss from cash flow hedges realized in net income (net of tax of $-0-, $-0- and $-0-)	(1)	—	1
Total	18	(4)	33
Comprehensive income	1,037	913	$ 1,090
Income allocated to preferred shareholders	—	50	49
Comprehensive income available to common shareholders	$ 1,037	$ 863	$ 1,041

See Combined Notes to Consolidated Financial Statements

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS

	December 31, 2024	December 31, 2023
	(in millions)	
ASSETS		
Current Assets:		
Cash and cash equivalents ($21 and $90 related to VIEs, respectively)	$ 24	$ 90
Investment in equity securities	561	541
Accounts receivable ($2 and $21 related to VIEs, respectively), less allowance for credit losses of $28 and $27, respectively	717	710
Accrued unbilled revenues ($2 and $2 related to VIEs, respectively), less allowance for credit losses of $2 and $2, respectively	521	516
Natural gas and coal inventory	173	197
Materials and supplies	541	573
Taxes receivable	121	94
Current assets held for sale	1,361	—
Regulatory assets	239	161
Prepaid expenses and other current assets ($2 and $15 related to VIEs, respectively)	123	145
Total current assets	4,381	3,027
Property, Plant and Equipment, Net:		
Property, plant and equipment	42,667	40,396
Less: accumulated depreciation and amortization	10,578	10,543
Property, plant and equipment, net	32,089	29,853
Other Assets:		
Goodwill	3,943	4,160
Regulatory assets ($313 and $402 related to VIEs, respectively)	3,108	2,513
Other non-current assets	247	162
Total other assets	7,298	6,835
Total Assets	$ 43,768	$ 39,715

See Combined Notes to Consolidated Financial Statements

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES
CONSOLIDATED BALANCE SHEETS - (continued)

	December 31, 2024	December 31, 2023
	(in millions, except par value and shares)	
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities:		
Short-term borrowings	$ 500	$ 4
Current portion of VIE Securitization Bonds long-term debt	13	178
Indexed debt, net	2	5
Current portion of other long-term debt	51	872
Indexed debt securities derivative	619	605
Accounts payable	1,320	917
Taxes accrued	329	291
Interest accrued	274	236
Dividends accrued	143	126
Customer deposits	93	111
Current liabilities held for sale	176	—
Other current liabilities	525	519
Total current liabilities	4,045	3,864
Other Liabilities:		
Deferred income taxes, net	4,389	4,079
Benefit obligations	550	572
Regulatory liabilities	2,999	3,208
Other non-current liabilities	722	766
Total other liabilities	8,660	8,625
Long-term Debt, net:		
VIE Securitization Bonds, net	308	320
Other long-term debt, net	20,089	17,239
Total long-term debt, net	20,397	17,559
Commitments and Contingencies (Note 14)		
Shareholders' Equity:		
Common stock, $0.01 par value, 1,000,000,000 shares authorized, 651,727,276 shares and 631,225,829 shares outstanding, respectively	6	6
Additional paid-in capital	9,105	8,604
Retained earnings	1,572	1,092
Accumulated other comprehensive loss	(17)	(35)
Total shareholders' equity	10,666	9,667
Total Liabilities and Shareholders' Equity	$ 43,768	$ 39,715

See Combined Notes to Consolidated Financial Statements

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES
STATEMENTS OF CONSOLIDATED CASH FLOWS

	Year Ended December 31,		
	2024	2023	2022
		(in millions)	
Cash Flows from Operating Activities:			
Net income	$ 1,019	$ 917	$ 1,057
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	1,439	1,401	1,288
Deferred income taxes	221	31	20
Loss (gain) on divestitures	—	13	(303)
Loss (gain) on equity securities	(20)	(31)	227
Loss (gain) on indexed debt securities	14	27	(325)
Pension contributions	(30)	(32)	(35)
Changes in other assets and liabilities:			
Accounts receivable and unbilled revenues, net	(84)	423	(461)
Inventory	42	167	(259)
Taxes receivable	(27)	(74)	(19)
Accounts payable	210	(302)	203
Current regulatory assets and liabilities	(86)	1,152	67
Non-current regulatory assets and liabilities	(644)	(109)	167
Other current assets and liabilities	101	162	(5)
Other non-current assets and liabilities	(30)	72	109
Other operating activities, net	14	60	79
Net cash provided by operating activities	2,139	3,877	1,810
Cash Flows from Investing Activities:			
Capital expenditures	(4,513)	(4,401)	(4,419)
Proceeds from sale of equity securities, net of transaction costs	—	—	702
Proceeds from divestitures	—	144	2,075
Other investing activities, net	24	24	14
Net cash used in investing activities	(4,489)	(4,233)	(1,628)
Cash Flows from Financing Activities:			
Increase (decrease) in short-term borrowings, net	(4)	(10)	452
Payment of obligation for finance lease	—	—	(485)
Payments of commercial paper, net	(539)	(1,055)	(74)
Proceeds from long-term debt and term loans, net	3,955	6,044	2,089
Payments of long-term debt and term loans, including make-whole premiums	(1,050)	(3,190)	(1,795)
Payment of debt issuance costs	(35)	(55)	(36)
Payment of dividends on Common Stock	(522)	(485)	(440)
Payment of dividends on Preferred Stock	—	(50)	(49)
Proceeds from issuance of Common Stock, net	494	—	—
Redemption of Series A Preferred Stock	—	(800)	—
Other financing activities, net	(28)	(25)	(7)
Net cash provided by (used in) financing activities	2,271	374	(345)
Net Increase (Decrease) in Cash, Cash Equivalents and Restricted Cash	(79)	18	(163)
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	109	91	254
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 30	$ 109	$ 91

See Combined Notes to Consolidated Financial Statements

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES
STATEMENTS OF CONSOLIDATED CHANGES IN EQUITY

	2024		2023		2022	
	Shares	Amount	Shares	Amount	Shares	Amount
	(in millions of dollars and shares, except authorized shares and per share amounts)					
Cumulative Preferred Stock, $0.01 par value; authorized 20,000,000 shares						
Balance, beginning of year	—	$ —	1	$ 790	1	$ 790
Redemption of Series A Preferred Stock	—	—	(1)	(790)	—	—
Balance, end of year	—	—	—	—	1	790
Common Stock, $0.01 par value; authorized 1,000,000,000 shares						
Balance, beginning of year	631	6	630	6	629	6
Issuances of Common Stock	19	—	—	—	—	—
Issuances related to benefit and investment plans	2	—	1	—	1	—
Balance, end of year	652	6	631	6	630	6
Additional Paid-in-Capital						
Balance, beginning of year		8,604		8,568		8,529
Issuances of Common Stock, net of issuance costs		494		—		—
Issuances related to benefit and investment plans		7		36		39
Balance, end of year		9,105		8,604		8,568
Retained Earnings						
Balance, beginning of year		1,092		709		154
Net income		1,019		917		1,057
Common Stock dividends declared (see Note 11)		(539)		(492)		(453)
Series A Preferred Stock dividends declared (see Note 11)		—		(42)		(49)
Balance, end of year		1,572		1,092		709
Accumulated Other Comprehensive Loss						
Balance, beginning of year		(35)		(31)		(64)
Other comprehensive income (loss)		18		(4)		33
Balance, end of year		(17)		(35)		(31)
Total Shareholders' Equity		$ 10,666		$ 9,667		$ 10,042

See Combined Notes to Consolidated Financial Statements

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Member of CenterPoint Energy Houston Electric, LLC

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of CenterPoint Energy Houston Electric, LLC and subsidiaries (an indirect wholly-owned subsidiary of CenterPoint Energy, Inc.) (the "Company") as of December 31, 2024 and 2023, the related statements of consolidated income, comprehensive income, changes in equity, and cash flows, for each of the three years in the period ended December 31, 2024, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2024 and 2023, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2024, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current-period audit of the financial statements that was communicated or required to be communicated to the audit committee and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Impact of Rate Regulation on the Financial Statements — Refer to Note 7 to the financial statements

Critical Audit Matter Description

The Company is subject to rate regulation by the Public Utility Commission of Texas ("PUCT"), which has jurisdiction with respect to the rates of electric transmission and distribution companies in Texas. Management has determined it meets the requirements under accounting principles generally accepted in the United States of America to prepare its financial statements applying the specialized rules to account for the effects of cost-based rate regulation. The impacts of accounting for the economics of rate regulation are pervasive to the financial statements and disclosures.

The Company's rates are subject to regulatory rate-setting processes by the PUCT. Rates are determined and approved in regulatory proceedings based on an analysis of the Company's costs to provide utility service and a return on, and recovery of, the Company's investment in the utility business. Regulatory decisions can have an impact on the recovery of costs, the rate of return earned on investment, and the timing and amount of assets to be recovered in rates. The PUCT's regulation of rates is premised on the full recovery of prudently incurred costs and a reasonable rate of return on invested capital. Decisions to be made by the PUCT in the future will impact the accounting for regulated operations, including decisions about the amount of allowable costs and return on invested capital included in rates and any refunds that may be required. While the Company has

indicated it expects to recover costs from customers through regulated rates, there is a risk that the PUCT will not approve: (1) full recovery of the costs of providing utility service, or (2) full recovery of all amounts invested in the utility business and a reasonable return on that investment.

We identified rate regulation as a critical audit matter due to the significant judgments made by management to support its assertions about certain affected account balances and disclosures and the high degree of subjectivity involved in assessing the impact of regulatory actions on the financial statements. Management's judgments include assessing the likelihood of (1) recovery in future rates of incurred costs, (2) a disallowance of capital investments made by the Company, and (3) refunds to customers. Given that certain of management's accounting judgments are based on assumptions about the outcome of decisions by the PUCT, auditing these judgments required specialized knowledge of accounting for rate regulation and the rate setting process.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the potential uncertainty of decisions by the PUCT included the following, among others:

- We evaluated the Company's disclosures related to the effects of rate regulation by testing certain recorded balances and evaluating regulatory developments.
- We read relevant regulatory orders issued by the PUCT, regulatory statutes, filings made by the Company and intervenors, and other external information. We evaluated relevant external information and compared it to certain recorded regulatory asset and liability balances for completeness.
- For certain regulatory matters, we inspected the Company's filings with the PUCT and the filings with the PUCT by intervenors to assess the likelihood of recovery in future rates or of a future reduction in rates based on precedents of the PUCT's treatment of similar costs under similar circumstances.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
February 20, 2025

We have served as the Company's auditor since 1932.

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC AND SUBSIDIARIES
(AN INDIRECT, WHOLLY-OWNED SUBSIDIARY OF CENTERPOINT ENERGY, INC.)
STATEMENTS OF CONSOLIDATED INCOME

	Year Ended December 31,		
	2024	2023	2022
	(in millions)		
Revenues	$ 3,939	$ 3,677	$ 3,412
Expenses:			
Operation and maintenance	1,927	1,673	1,650
Depreciation and amortization	762	748	670
Taxes other than income taxes	295	262	261
Total	2,984	2,683	2,581
Operating Income	955	994	831
Other Income (Expense):			
Interest expense and other finance charges	(311)	(259)	(202)
Interest expense on Securitization Bonds	(3)	(8)	(13)
Other income, net	43	34	19
Total	(271)	(233)	(196)
Income Before Income Taxes	684	761	635
Income tax expense	138	168	125
Net Income	$ 546	$ 593	$ 510

See Combined Notes to Consolidated Financial Statements

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC AND SUBSIDIARIES
(AN INDIRECT, WHOLLY-OWNED SUBSIDIARY OF CENTERPOINT ENERGY, INC.)
STATEMENTS OF CONSOLIDATED COMPREHENSIVE INCOME

	Year Ended December 31,		
	2024	2023	2022
		(in millions)	
Net income	$ 546	$ 593	$ 510
Other comprehensive income:			
Adjustment to pension and other postretirement plans (net of tax of $-0-, $-0- and $-0-)	(1)	—	—
Total	(1)	—	—
Comprehensive income	$ 545	$ 593	$ 510

See Combined Notes to Consolidated Financial Statements

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC AND SUBSIDIARIES
(AN INDIRECT, WHOLLY-OWNED SUBSIDIARY OF CENTERPOINT ENERGY, INC.)
CONSOLIDATED BALANCE SHEETS

	December 31, 2024	December 31, 2023
	(in millions)	
ASSETS		
Current Assets:		
Cash and cash equivalents ($14 and $76 related to VIEs, respectively)	$ 14	$ 76
Accounts and notes receivable, net ($0 and $19 related to VIEs, respectively), less allowance for credit losses of $2 and $1, respectively	307	295
Accounts and notes receivable—affiliated companies	371	251
Accrued unbilled revenues	137	142
Materials and supplies	392	409
Taxes receivable	—	38
Prepaid expenses and other current assets ($0 and $13 related to VIEs, respectively)	44	48
Total current assets	1,265	1,259
Property, Plant and Equipment, Net		
Property, plant and equipment	21,750	19,515
Less: accumulated depreciation and amortization	4,628	4,469
Property, plant and equipment, net	17,122	15,046
Other Assets:		
Regulatory assets ($0 and $74 related to VIEs, respectively)	1,284	752
Other non-current assets	41	29
Total other assets	1,325	781
Total Assets	$ 19,712	$ 17,086

See Combined Notes to Consolidated Financial Statements

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC AND SUBSIDIARIES
(AN INDIRECT, WHOLLY-OWNED SUBSIDIARY OF CENTERPOINT ENERGY, INC.)
CONSOLIDATED BALANCE SHEETS – (continued)

	December 31, 2024	December 31, 2023
	(in millions)	
LIABILITIES AND MEMBER'S EQUITY		
Current Liabilities:		
Short-term borrowings	$ 500	$ —
Current portion of VIE Securitization Bonds long-term debt	—	161
Accounts payable	681	351
Accounts payable—affiliated companies	119	104
Taxes accrued	189	155
Interest accrued	108	99
Other current liabilities	144	111
Total current liabilities	1,741	981
Other Liabilities:		
Deferred income taxes, net	1,502	1,406
Benefit obligations	32	32
Regulatory liabilities	861	1,025
Other non-current liabilities	95	107
Total other liabilities	2,490	2,570
Long-Term Debt, net	8,322	7,426
Commitments and Contingencies (Note 14)		
Member's Equity:		
Common stock	—	—
Additional paid-in capital	5,589	4,745
Retained earnings	1,571	1,364
Accumulated other comprehensive loss	(1)	—
Total member's equity	7,159	6,109
Total Liabilities and Member's Equity	$ 19,712	$ 17,086

See Combined Notes to Consolidated Financial Statements

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC AND SUBSIDIARIES
(AN INDIRECT, WHOLLY-OWNED SUBSIDIARY OF CENTERPOINT ENERGY, INC.)
STATEMENTS OF CONSOLIDATED CASH FLOWS

	Year Ended December 31,		
	2024	2023	2022
		(in millions)	
Cash Flows from Operating Activities:			
Net income	$ 546	$ 593	$ 510
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	762	748	670
Deferred income taxes	61	160	86
Changes in other assets and liabilities:			
Accounts receivable and unbilled revenues, net	(10)	16	(63)
Accounts receivable/payable–affiliated companies	25	(1)	47
Inventory	17	62	(179)
Accounts payable	89	(60)	(7)
Taxes receivable	38	(38)	—
Current regulatory assets and liabilities	2	6	(20)
Non-current regulatory assets and liabilities	(608)	(136)	(21)
Other current assets and liabilities	43	28	(20)
Other non-current assets and liabilities	(8)	35	(25)
Other operating activities, net	3	(12)	(12)
Net cash provided by operating activities	960	1,401	966
Cash Flows from Investing Activities:			
Capital expenditures	(2,642)	(2,279)	(2,436)
Increase in notes receivable–affiliated companies	(130)	(238)	—
Other investing activities, net	5	14	1
Net cash used in investing activities	(2,767)	(2,503)	(2,435)
Cash Flows from Financing Activities:			
Proceeds from long-term debt and term loan, net	1,397	1,398	1,589
Payments of long-term debt	(161)	(156)	(720)
Increase (decrease) in notes payable–affiliated companies	—	(642)	130
Payment of debt issuance costs	(8)	(13)	(17)
Contribution from parent	844	885	1,143
Dividend to parent	(339)	(367)	(316)
Payment of obligation for finance lease	—	—	(485)
Other financing activities, net	(1)	(2)	—
Net cash provided by financing activities	1,732	1,103	1,324
Net Increase (Decrease) in Cash, Cash Equivalents and Restricted Cash	(75)	1	(145)
Cash, Cash Equivalents and Restricted Cash at Beginning of the Period	89	88	233
Cash, Cash Equivalents and Restricted Cash at End of the Period	$ 14	$ 89	$ 88

See Combined Notes to Consolidated Financial Statements

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC AND SUBSIDIARIES
(AN INDIRECT, WHOLLY-OWNED SUBSIDIARY OF CENTERPOINT ENERGY, INC.)
STATEMENTS OF CONSOLIDATED CHANGES IN EQUITY

	2024		2023		2022	
	Shares	Amount	Shares	Amount	Shares	Amount
	(in millions, except share amounts)					
Common Stock						
Balance, beginning of year	1,000	$ —	1,000	$ —	1,000	$ —
Balance, end of year	1,000	—	1,000	—	1,000	—
Additional Paid-in-Capital						
Balance, beginning of year		4,745		3,860		2,678
Non-cash contribution from parent		—		—		38
Contribution from parent		844		885		1,143
Other		—		—		1
Balance, end of year		5,589		4,745		3,860
Retained Earnings						
Balance, beginning of year		1,364		1,138		944
Net income		546		593		510
Dividend to parent		(339)		(367)		(316)
Balance, end of year		1,571		1,364		1,138
Accumulated Other Comprehensive Loss						
Balance, beginning of year		—		—		—
Other comprehensive loss		(1)		—		—
Balance, end of year		(1)		—		—
Total Member's Equity		$ 7,159		$ 6,109		$ 4,998

See Combined Notes to Consolidated Financial Statements

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholder of CenterPoint Energy Resources Corp.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of CenterPoint Energy Resources Corp. and subsidiaries (an indirect wholly-owned subsidiary of CenterPoint Energy, Inc.) (the "Company") as of December 31, 2024 and 2023, the related statements of consolidated income, comprehensive income, changes in equity, and cash flows, for each of the three years in the period ended December 31, 2024, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2024 and 2023, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2024, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits, we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current-period audit of the financial statements that was communicated or required to be communicated to the audit committee and that (1) relates to accounts or disclosures that are material to the financial statements and (2) involved especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Impact of Rate Regulation on the Financial Statements — Refer to Note 7 to the financial statements

Critical Audit Matter Description

The Company is subject to rate regulation by regulators and commissions in various jurisdictions (collectively, the "Commissions") that have jurisdiction with respect to the rates of gas transmission and distribution companies in those jurisdictions. Management has determined its regulated operations meet the requirements under accounting principles generally accepted in the United States of America to prepare its financial statements applying the specialized rules to account for the effects of cost-based rate regulation. The impacts of accounting for the economics of rate regulation are pervasive to the financial statements and disclosures.

The Company's rates are subject to regulatory rate-setting processes by the Commissions. Rates are determined and approved in regulatory proceedings based on an analysis of the Company's costs to provide utility service and a return on, and recovery of, the Company's investment in the utility business. Regulatory decisions can have an impact on the recovery of costs, the rate of return earned on investment, and the timing and amount of assets to be recovered in rates. The Commissions' regulation of rates is premised on the full recovery of prudently incurred costs and a reasonable rate of return on invested capital. Decisions to be made by the Commissions in the future will impact the accounting for regulated operations, including decisions about the

amount of allowable costs and return on invested capital included in rates and any refunds that may be required. While the Company has indicated it expects to recover costs from customers through regulated rates, there is a risk that the Commissions will not approve: (1) full recovery of the costs of providing utility service, or (2) full recovery of all amounts invested in the utility business and a reasonable return on that investment.

We identified rate regulation as a critical audit matter due to the significant judgments made by management to support its assertions about certain affected account balances and disclosures and the high degree of subjectivity involved in assessing the impact of regulatory actions on the financial statements. Management's judgments include assessing the likelihood of (1) recovery in future rates of incurred costs, (2) a disallowance of capital investments made by the Company and (3) refunds to customers. Given that certain of management's accounting judgments are based on assumptions about the outcome of decisions by the Commissions, auditing these judgments required specialized knowledge of accounting for rate regulation and the rate setting process.

How the Critical Audit Matter Was Addressed in the Audit

Our audit procedures related to the potential uncertainty of decisions by the Commissions included the following, among others:

- We evaluated the Company's disclosures related to the effects of rate regulation by testing certain recorded balances and evaluating regulatory developments.

- We read relevant regulatory orders issued by the Commissions, regulatory statutes, filings made by the Company and intervenors, and other external information. We evaluated relevant external information and compared it to certain recorded regulatory asset and liability balances for completeness.

- For certain regulatory matters, we inspected the Company's filings with the Commissions and the filings with the Commissions by intervenors to assess the likelihood of recovery in future rates or of a future reduction in rates based on precedents of the Commissions' treatment of similar costs under similar circumstances.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
February 20, 2025

We have served as the Company's auditor since 1997.

CENTERPOINT ENERGY RESOURCES CORP. AND SUBSIDIARIES
(AN INDIRECT, WHOLLY-OWNED SUBSIDIARY OF CENTERPOINT ENERGY, INC.)
STATEMENTS OF CONSOLIDATED INCOME

	Year Ended December 31,		
	2024	2023	2022
		(in millions)	
Revenues:			
Utility revenues	$ 3,878	$ 4,107	$ 4,764
Non-utility revenues	47	42	36
Total	3,925	4,149	4,800
Expenses:			
Utility natural gas	1,489	1,856	2,607
Non-utility cost of revenues, including natural gas	3	3	4
Operation and maintenance	848	904	886
Depreciation and amortization	522	493	448
Taxes other than income taxes	234	243	257
Total	3,096	3,499	4,202
Operating Income	829	650	598
Other Income (Expense):			
Gain on sale	—	—	557
Interest expense and other finance charges	(197)	(178)	(130)
Other income (expense), net	12	14	(64)
Total	(185)	(164)	363
Income Before Income Taxes	644	486	961
Income tax expense (benefit)	104	(26)	236
Net Income	$ 540	$ 512	$ 725

See Combined Notes to Consolidated Financial Statements

CENTERPOINT ENERGY RESOURCES CORP. AND SUBSIDIARIES
(AN INDIRECT, WHOLLY-OWNED SUBSIDIARY OF CENTERPOINT ENERGY, INC.)
STATEMENTS OF CONSOLIDATED COMPREHENSIVE INCOME

	Year Ended December 31,		
	2024	2023	2022
		(in millions)	
Net income	$ 540	$ 512	$ 725
Other comprehensive income:			
Adjustment to pension and other postretirement plans (net of tax of $-0-, $-0- and $4)	1	—	6
Total	1	—	6
Comprehensive income	$ 541	$ 512	$ 731

See Combined Notes to Consolidated Financial Statements

CENTERPOINT ENERGY RESOURCES CORP. AND SUBSIDIARIES
(AN INDIRECT, WHOLLY-OWNED SUBSIDIARY OF CENTERPOINT ENERGY, INC.)
CONSOLIDATED BALANCE SHEETS

	December 31, 2024	December 31, 2023
	(in millions)	
ASSETS		
Current Assets:		
Cash and cash equivalents	$ 2	$ 1
Accounts receivable, less allowance for credit losses of $24 and $25, respectively	349	356
Accrued unbilled revenue, less allowance for credit losses of $2 and $1, respectively	338	329
Accounts and notes receivable — affiliated companies	6	43
Material and supplies	105	107
Natural gas inventory	137	156
Taxes receivable	46	101
Current assets held for sale	1,266	—
Regulatory assets	238	161
Prepaid expenses and other current assets	50	55
Total current assets	2,537	1,309
Property, Plant and Equipment, Net:		
Property, plant and equipment	15,552	15,672
Less: accumulated depreciation and amortization	4,146	4,169
Property, plant and equipment, net	11,406	11,503
Other Assets:		
Goodwill	1,461	1,583
Regulatory assets	903	850
Other non-current assets	118	51
Total other assets	2,482	2,484
Total Assets	$ 16,425	$ 15,296

See Combined Notes to Consolidated Financial Statements

CENTERPOINT ENERGY RESOURCES CORP. AND SUBSIDIARIES
(AN INDIRECT, WHOLLY-OWNED SUBSIDIARY OF CENTERPOINT ENERGY, INC.)
CONSOLIDATED BALANCE SHEETS - (continued)

	December 31, 2024	December 31, 2023
	(in millions)	
LIABILITIES AND STOCKHOLDER'S EQUITY		
Current Liabilities:		
Short-term borrowings	$ —	$ 4
Current portion of long-term debt	10	—
Accounts payable	405	392
Accounts payable–affiliated companies	101	99
Taxes accrued	150	145
Interest accrued	82	70
Customer deposits	81	95
Current liabilities held for sale	176	—
Other current liabilities	255	282
Total current liabilities	1,260	1,087
Other Liabilities:		
Deferred income taxes, net	1,370	1,246
Benefit obligations	63	74
Regulatory liabilities	1,887	1,882
Other non-current liabilities	403	458
Total other liabilities	3,723	3,660
Long-Term Debt, net	5,174	4,670
Commitments and Contingencies (Note 14)		
Stockholder's Equity:		
Common stock	—	—
Additional paid-in capital	4,519	4,229
Retained earnings	1,732	1,634
Accumulated other comprehensive income	17	16
Total stockholder's equity	6,268	5,879
Total Liabilities and Stockholder's Equity	$ 16,425	$ 15,296

See Combined Notes to Consolidated Financial Statements

CENTERPOINT ENERGY RESOURCES CORP. AND SUBSIDIARIES
(AN INDIRECT, WHOLLY-OWNED SUBSIDIARY OF CENTERPOINT ENERGY, INC.)
STATEMENTS OF CONSOLIDATED CASH FLOWS

	Year Ended December 31,		
	2024	2023	2022
		(in millions)	
Cash Flows from Operating Activities:			
Net income	$ 540	$ 512	$ 725
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	522	493	448
Deferred income taxes	55	(41)	178
Gain on divestitures	—	—	(557)
Changes in other assets and liabilities:			
Accounts receivable and unbilled revenues, net	(73)	410	(376)
Accounts receivable/payable–affiliated companies	38	(81)	41
Inventory	6	101	(50)
Taxes receivable	55	(89)	—
Accounts payable	43	(250)	190
Current regulatory assets and liabilities	(85)	1,098	112
Non-current regulatory assets and liabilities	(31)	54	132
Other current assets and liabilities	24	85	13
Other non-current assets and liabilities	(2)	(1)	(2)
Other operating activities, net	(24)	21	2
Net cash provided by operating activities	1,068	2,312	856
Cash Flows from Investing Activities:			
Capital expenditures	(1,439)	(1,619)	(1,661)
Decrease (increase) in notes receivable–affiliated companies	1	(1)	—
Proceeds from divestitures	—	—	2,075
Other investing activities, net	19	(23)	(8)
Net cash provided by (used in) investing activities	(1,419)	(1,643)	406
Cash Flows from Financing Activities:			
Increase (decrease) in short-term borrowings, net	(4)	(10)	452
Payments of commercial paper, net	115	(321)	(94)
Proceeds from long-term debt and term loans, net	399	2,006	927
Payments of long-term debt and term loans	—	(2,332)	(475)
Increase in notes payable-affiliated companies	—	—	(1,517)
Payments of debt issuance costs	(3)	(14)	(14)
Contribution from parent	290	500	289
Dividends to parent	(442)	(496)	(844)
Other financing activities, net	(3)	(1)	(1)
Net cash provided by (used in) financing activities	352	(668)	(1,277)
Net Increase (Decrease) in Cash, Cash Equivalents and Restricted Cash	1	1	(15)
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	1	—	15
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 2	$ 1	$ —

See Combined Notes to Consolidated Financial Statements

CENTERPOINT ENERGY RESOURCES CORP. AND SUBSIDIARIES
(AN INDIRECT, WHOLLY-OWNED SUBSIDIARY OF CENTERPOINT ENERGY, INC.)
STATEMENTS OF CONSOLIDATED CHANGES IN EQUITY

	2024		2023		2022	
	Shares	Amount	Shares	Amount	Shares	Amount
	(in millions, except share amounts)					
Common Stock						
Balance, beginning of year	1,000	$ —	1,000	$ —	1,000	$ —
Balance, end of year	1,000	—	1,000	—	1,000	—
Additional Paid-in-Capital						
Balance, beginning of year		4,229		3,729		4,106
Non-cash contribution from parent		—		—		54
Contribution from parent		290		500		289
Dividend to parent for sale of Arkansas and Oklahoma Natural Gas businesses		—		—		(720)
Balance, end of year		4,519		4,229		3,729
Retained Earnings						
Balance, beginning of year		1,634		1,618		1,017
Net income		540		512		725
Dividend to parent		(442)		(496)		(124)
Balance, end of year		1,732		1,634		1,618
Accumulated Other Comprehensive Income						
Balance, beginning of year		16		16		10
Other comprehensive income		1		—		6
Balance, end of year		17		16		16
Total Stockholder's Equity		$ 6,268		$ 5,879		$ 5,363

See Combined Notes to Consolidated Financial Statements

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES
CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC AND SUBSIDIARIES
CENTERPOINT ENERGY RESOURCES CORP. AND SUBSIDIARIES

COMBINED NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Background and Basis of Presentation

General. This combined Form 10-K is filed separately by three registrants: CenterPoint Energy, Inc., CenterPoint Energy Houston Electric, LLC and CenterPoint Energy Resources Corp. Information contained herein relating to any individual registrant is filed by such registrant solely on its own behalf. Each registrant makes no representation as to information relating exclusively to the other registrants or the subsidiaries of CenterPoint Energy, Inc. other than itself or its subsidiaries.

Except as discussed in Note 12, no registrant has an obligation in respect of any other registrant's debt securities, and holders of such debt securities should not consider the financial resources or results of operations of any registrant other than the obligor in making a decision with respect to such securities.

Basis of Presentation. Included in this combined Form 10-K are the consolidated financial statements of the Registrants. The Combined Notes to the Consolidated Financial Statements apply to all Registrants and specific references to Houston Electric and CERC herein also pertain to CenterPoint Energy, unless otherwise indicated. Additionally, certain amounts from prior years have been reclassified to conform to the current presentation.

Background. CenterPoint Energy is a public utility holding company. CenterPoint Energy's operating subsidiaries own and operate electric transmission, distribution and generation facilities and natural gas distribution systems.

As of December 31, 2024, CenterPoint Energy's operating subsidiaries were as follows:

- Houston Electric owns and operates electric transmission and distribution facilities in the Texas Gulf Coast area that includes the city of Houston;

- CERC Corp. (i) directly owns and operates natural gas distribution systems in Louisiana, Minnesota, Mississippi and Texas, (ii) indirectly, through Indiana Gas and CEOH, owns and operates natural gas distribution systems in Indiana and Ohio, respectively, and (iii) owns and operates permanent pipeline connections through interconnects with various interstate and intrastate pipeline companies through CEIP; and

- SIGECO provides energy delivery services to electric and natural gas customers located in and near Evansville in southwestern Indiana and owns and operates electric generation assets to serve its electric customers and optimizes those assets in the wholesale power market.

As of December 31, 2024, CenterPoint Energy's reportable segments were Electric, Natural Gas, and Corporate and Other. Houston Electric and CERC each consist of a single reportable segment. For a description of CenterPoint Energy's reportable segments, see Note 16.

On June 30, 2023, CenterPoint Energy completed the sale of its indirect subsidiary, Energy Systems Group, to an unaffiliated third party. On February 19, 2024, CenterPoint Energy, through its subsidiary CERC Corp., entered into the LAMS Asset Purchase Agreement to sell its Louisiana and Mississippi natural gas LDC businesses. The transaction is expected to close in the first quarter of 2025. For additional information, see Note 4.

Principles of Consolidation. The accompanying consolidated financial statements are prepared in conformity with GAAP. The accounts of the Registrants and their wholly-owned and majority-owned and controlled subsidiaries are included in the consolidated financial statements. All intercompany transactions and balances are eliminated in consolidation; however, intercompany profits have not been eliminated when such amounts are probable of recovery under the affiliates' rate regulation process.

As of December 31, 2024, CenterPoint Energy, Houston Electric and SIGECO had VIEs including Bond Company IV and the SIGECO Securitization Subsidiary, which are consolidated. The consolidated VIEs are wholly-owned, bankruptcy-remote, special purpose entities that were formed solely for the purpose of securitizing transition property or facilitating the securitization financing of qualified costs. CenterPoint Energy, through SIGECO, has a controlling financial interest in the SIGECO Securitization Subsidiary and is the VIE's primary beneficiary. For further information, see Note 7. Houston Electric has a controlling financial interest in Bond Company IV and is the VIE's primary beneficiary. Creditors of CenterPoint Energy, Houston Electric and SIGECO have no recourse to any assets or revenues of Bond Company IV or the SIGECO Securitization Subsidiary, as applicable. The Securitization Bonds issued by these VIEs are payable only from and secured by transition or securitization property, as applicable, and the bondholders have no recourse to the general credit of CenterPoint Energy, Houston Electric or SIGECO.

(2) Summary of Significant Accounting Policies

(a) Use of Estimates

The preparation of our consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

(b) Revenues

The Registrants record revenue for electricity delivery and natural gas sales and services under the accrual method and these revenues are recognized upon delivery to customers. Electricity deliveries not billed by month-end are accrued based on actual AMS meter data, supply volumes, estimated line loss and applicable tariff rates. Natural gas sales not billed by month-end are accrued based upon estimated purchased gas volumes, estimated lost and unaccounted for gas and currently effective tariff rates. For further discussion, see Note 5.

(c) MISO Transactions

Indiana Electric is a member of the MISO. MISO-related purchase and sale transactions are recorded using settlement information provided by the MISO. These purchase and sale transactions are accounted for on at least a net hourly position, in which net purchases within that interval are recorded as Utility natural gas, fuel and purchased power and net sales within that interval are recorded as Utility revenues on CenterPoint Energy's Statements of Consolidated Income. On occasion, prior period transactions are resettled outside the routine process due to a change in the MISO's tariff or a material interpretation thereof. Expenses associated with resettlements are recorded once the resettlement is probable and the resettlement amount can be estimated. Revenues associated with resettlements are recognized when the amount is determinable and collectability is reasonably assured.

(d) Environmental Costs

The Registrants (i) expense or capitalize environmental expenditures, as appropriate, depending on their future economic benefit; (ii) expense amounts that relate to an existing condition caused by past operations that do not have future economic benefit; and (iii) record undiscounted liabilities related to these future costs when environmental assessments and/or remediation activities are probable and the costs can be reasonably estimated.

(e) Cash and Cash Equivalents and Restricted Cash

For purposes of reporting cash flows, the Registrants consider cash equivalents to be short-term, highly-liquid investments with maturities of three months or less from the date of purchase. Cash and cash equivalents held by the Bond Companies and the SIGECO Securitization Subsidiary (VIEs) solely to support servicing the Securitization Bonds as of December 31, 2024 and 2023 are reflected on CenterPoint Energy's and Houston Electric's Consolidated Balance Sheets.

In connection with the issuance of Securitization Bonds, CenterPoint Energy and Houston Electric were required to establish restricted cash accounts to collateralize the bonds that were issued in these financing transactions. These restricted cash accounts are not available for withdrawal until the maturity of the bonds and are not included in cash and cash equivalents. For more information on restricted cash, see Note 17.

(f) Accounts Receivable and Allowance for Credit Losses

Accounts receivable are recorded at the invoiced amount and do not bear interest. Management reviews historical write-offs, current available information and reasonable and supportable forecasts to estimate and establish allowance for credit losses. Account balances are charged off against the allowance when management determines it is probable that the receivable will not be recovered. See Note 7 for further information about regulatory deferrals of bad debt expense, including those related to COVID-19 and the February 2021 Winter Storm Event.

(g) Inventory

The Registrants' inventory consists principally of materials and supplies, and for CERC, natural gas, and for CenterPoint Energy, coal inventory. Materials and supplies are valued at the lower of average cost or market, are recorded to inventory when purchased and subsequently charged to expense or capitalized to plant when installed. Inventory related to CenterPoint Energy's regulated operations is valued at historical cost consistent with ratemaking treatment. Coal inventory is valued at average cost. Certain natural gas in storage at CenterPoint Energy's and CERC's utilities are recorded using the last in, first out (LIFO) method. CenterPoint Energy's and CERC's balances in inventory that were valued using LIFO method were as follows:

	Year Ended December 31,			
	2024	2023 (1)	2024	2023 (1)
	CenterPoint Energy		CERC	
	(in millions)			
LIFO inventory	$ 94	$ 106	$ 73	$ 86

(1) Based on the average cost of gas purchased during December 2024, CenterPoint Energy's cost of replacing inventories carried at LIFO cost was $1 million less than the carrying value at December 31, 2024. CERC's cost of replacing inventories carried at LIFO cost was $4 million more than the carrying value at December 31, 2024.

(h) Long-lived Assets

The Registrants record property, plant and equipment at historical cost and expense repair and maintenance costs as incurred.

The Registrants periodically evaluate long-lived assets, including property, plant and equipment, when events or changes in circumstances indicate that the carrying value of these assets may not be recoverable. For rate-regulated businesses, recoverability of long-lived assets is assessed by determining if a capital disallowance from a regulator is probable through monitoring the outcome of rate cases and other proceedings. For businesses that are not rate-regulated, recoverability is assessed based on an estimate of undiscounted cash flows attributable to the assets compared to the carrying value of the assets. No long-lived asset impairments were recorded in 2024, 2023 or 2022.

The Registrants compute depreciation and amortization using the straight-line method based on economic lives or regulatory-mandated recovery periods. Amortization expense includes amortization of certain regulatory assets.

(i) Goodwill

CenterPoint Energy and CERC perform goodwill impairment tests at least annually and evaluate goodwill when events or changes in circumstances indicate that its carrying value may not be recoverable. Goodwill is evaluated for impairment by performing a qualitative assessment or using a quantitative test. If CenterPoint Energy or CERC chooses to perform a qualitative assessment and determine it is more likely than not that the fair value of a reporting unit is less than its carrying amount, the quantitative test is then performed; otherwise, no further testing is required. The quantitative test, if required, is performed by comparing the fair value of each reporting unit with the carrying amount of the reporting unit, including goodwill. The estimated fair value of the reporting unit is primarily determined based on an income approach or a weighted combination of income and market approaches. When the carrying amount is in excess of the estimated fair value of the reporting unit, the excess amount is recorded as an impairment charge, not to exceed the carrying amount of goodwill. CenterPoint Energy includes deferred tax assets and liabilities within its reporting unit's carrying value for the purposes of annual and interim impairment tests, regardless of whether the estimated fair value reflects the disposition of such assets and liabilities. For further information about the goodwill impairment tests, see Note 6.

(j) Regulatory Assets and Liabilities

The Registrants apply the guidance for accounting for regulated operations within the Electric reportable segment and the Natural Gas reportable segment. The Registrants' rate-regulated subsidiaries may collect revenues subject to refund pending final determination in rate proceedings. In connection with such revenues, estimated rate refund liabilities are recorded which reflect management's current judgment of the ultimate outcomes of the proceedings.

The Registrants' rate-regulated businesses recognize removal costs as a component of depreciation expense in accordance with regulatory treatment. In addition, a portion of the amount of removal costs collected from customers that relate to AROs has been reflected as an asset retirement liability in accordance with accounting guidance for AROs.

For further detail on the Registrants' regulatory assets and liabilities, see Note 7.

(k) Capitalization and Deferral of Interest, including AFUDC

The Registrants capitalize interest and AFUDC as a component of projects under construction and amortize it over the assets' estimated useful lives once the assets are placed in service. Additionally, the Registrants defer interest costs into a regulatory asset when amounts are probable of recovery. Deferred debt interest is amortized over the recovery period for rate-making purposes. AFUDC represents the composite interest cost of borrowed funds and a reasonable return on the equity funds used for construction for subsidiaries that apply the guidance for accounting for regulated operations. Although AFUDC increases both property, plant and equipment and earnings, it is realized in cash when the assets are included in rates. The table below includes interest capitalized or deferred for the periods presented:

	Year Ended December 31,								
	2024			2023			2022		
	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC
	(in millions)								
Capitalized interest and AFUDC debt (1)	$ 33	$ 18	$ 8	$ 32	$ 18	$ 6	$ 26	$ 14	$ 7
AFUDC equity (2)	66	33	17	62	32	14	37	24	5
Deferred debt interest (3)	65	24	36	65	16	43	51	12	36

(1) Included in Interest expense and other finance charges on the Registrants' respective Statements of Consolidated Income.
(2) Included in Other income (expense), net on the Registrants' respective Statements of Consolidated Income.
(3) Represents the amount on certain regulatory assets that are authorized to earn a return, such as debt post in-service carrying costs on property, plant and equipment, gas costs, storm restoration costs, and TEEEF (including returns on both regulatory and lease assets) and is included in Interest expense and other finance charges on the Registrants' respective Statements of Consolidated Income.

(l) Leases

An arrangement is determined to be a lease at inception based on whether the Registrant has the right to control the use of an identified asset. ROU assets represent the Registrants' right to use the underlying asset for the lease term and lease liabilities represent the Registrants' obligation to make lease payments arising from the lease. ROU assets and liabilities are recognized at the lease commencement date based on the present value of lease payments over the lease term, including payments at commencement that depend on an index or rate. Most leases in which the Registrants are the lessee do not have a readily determinable implicit rate, so an incremental borrowing rate, based on the information available at the lease commencement date, is utilized to determine the present value of lease payments. When a secured borrowing rate is not readily available, unsecured borrowing rates are adjusted for the effects of collateral to determine the incremental borrowing rate. Each Registrant uses the implicit rate for agreements in which it is a lessor. Lease income and expense for operating leases and ROU amortization for finance leases are recognized on a straight-line basis over the lease term.

The Registrants have lease agreements with lease and non-lease components and have elected the practical expedient to combine lease and non-lease components for certain classes of leases, such as office buildings and temporary generation. For classes of leases in which lease and non-lease components are not combined, consideration is allocated between components based on the stand-alone prices. Sublease income is not significant to the Registrants.

The Registrants' lease agreements do not contain any material residual value guarantees, material restrictions or material covenants. Except as described in Note 18, there are no lease transactions between related parties. Agreements in which the Registrants are lessors do not include provisions for the lessee to purchase the assets. Because risk is minimal, the Registrants do not take any significant actions to manage risk associated with the residual value of their leased assets.

The Registrants' operating lease agreements are primarily equipment and real property leases, including land and office facility leases. CenterPoint Energy and Houston Electric also have finance lease agreements for temporary generation. The Registrants' lease terms may include options to extend or terminate a lease when it is reasonably certain that those options will be exercised. The Registrants have elected an accounting policy that exempts leases with terms of one year or less from the recognition requirements of ASC 842.

(m) Income Taxes

Houston Electric and CERC are included in CenterPoint Energy's U.S. federal consolidated income tax return. Houston Electric and CERC report their income tax provision on a separate entity basis pursuant to a tax sharing policy with CenterPoint Energy. Current federal and certain state income taxes are payable to or receivable from CenterPoint Energy.

The Registrants use the asset and liability method of accounting for deferred income taxes. Deferred income tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax basis. A valuation allowance is established against deferred tax assets for which management believes realization is not considered to be more likely than not. The Registrants recognize interest and penalties as a component of income tax expense (benefit), as applicable, in their respective Statements of Consolidated Income.

To the extent certain EDIT of the Registrants' rate-regulated subsidiaries may be recoverable or payable through future rates, regulatory assets and liabilities have been recorded, respectively. See Note 13 for further discussion.

The Registrants use the portfolio approach to recognize income tax effects on other comprehensive income from accumulated other comprehensive income.

Investment tax credits are deferred and amortized to income over the approximate lives of the related property. Production tax credits extended by the IRA may be used to reduce current federal income taxes payable.

(n) Investments in Equity Securities (CenterPoint Energy)

CenterPoint Energy reports equity securities at estimated fair value in the Consolidated Balance Sheets, and any gains and losses, net of any transaction costs, are recorded as Gain (loss) on equity securities in the Statements of Consolidated Income.

(o) Assets Held for Sale

Generally, a long-lived asset to be sold is classified as held for sale in the period in which management, with approval from the Board of Directors, as applicable, commits to a plan to sell, and a sale is expected to be completed within one year. The Registrants record assets and liabilities held for sale, or the disposal group, at the lower of their carrying value or their estimated fair value less cost to sell. If a disposal group reflects a component of a reporting unit and meets the definition of a business, the goodwill within that reporting unit is allocated to the disposal group based on the relative fair value of the components representing a business that will be retained and disposed. Goodwill is not allocated to a portion of a reporting unit that does not meet the definition of a business.

As of December 31, 2024, certain assets and liabilities representing the Louisiana and Mississippi natural gas LDC businesses met the held for sale criteria. The sale will be considered an asset sale for tax purposes, requiring net deferred tax liabilities to be excluded from held for sale balances. For further discussion of the sale, see Note 4.

Fair value is the amount at which an asset, liability or business could be bought or sold in a current transaction between willing parties and may be estimated using a number of techniques, including quoted market prices, present value techniques based on estimates of cash flows, or multiples of earnings or revenue performance measures. The fair value could be different if different estimates and assumptions in these valuation techniques were applied.

Fair value measurements require significant judgment and often unobservable inputs, including (i) projected timing and amount of future cash flows, which factor in planned growth initiatives, (ii) the regulatory environment, as applicable, and (iii) discount rates reflecting risk inherent in the future market prices. Changes in these assumptions could have a significant impact on the resulting fair value.

(p) Preferred Stock and Dividends

Preferred stock is evaluated to determine balance sheet classification, and all conversion and redemption features are evaluated for bifurcation treatment. Proceeds received net of issuance costs are recognized on the settlement date. Cash dividends become a liability once declared. Income available to common stockholders is computed by deducting from net income the dividends accumulated and earned during the period on cumulative preferred stock.

(q) Recent Accounting Pronouncements

On December 31, 2024, the Registrants adopted ASU 2023-07, Segment Reporting (Topic 280): Improvements to Reportable Segment Disclosures ("ASU 2023-07"), which updates segment disclosure requirements through enhanced disclosures around significant segment expenses. The Registrants applied the provision retrospectively to all periods presented for each Registrants' reportable segment as further described. See Note 16 for further discussion of our segment reporting.

In November 2024, the FASB issued ASU 2024-03, Income Statement—Reporting Comprehensive Income (Topic 220): Expense Disaggregation Disclosures ("ASU 2024-03"). This ASU improves disclosure of a public business entity's expense by requiring disaggregated disclosure of expenses in commonly presented expense captions. ASU 2024-03 is effective for annual periods beginning after December 15, 2026, and for interim periods beginning after December 15, 2027. Early adoption is permitted. The Registrants are currently evaluating the impact of this ASU on their respective consolidated financial statements.

In December 2023, the FASB issued ASU 2023-09, Income Taxes (Topic 740): Improvements to Income Tax Disclosures ("ASU 2023-09"). This ASU enhances the transparency of income tax disclosures related to rate reconciliation and income taxes. ASU 2023-09 is effective for annual periods beginning after December 15, 2024. Early adoption is permitted. The Registrants are currently evaluating the impact of this ASU on their respective consolidated financial statements.

Management believes that all other recently adopted and recently issued accounting standards that are not yet effective will not have a material impact on the Registrants' financial position, results of operations or cash flows upon adoption.

(3) Property, Plant and Equipment

(a) Property, Plant and Equipment

Property, plant and equipment includes the following:

		December 31, 2024			December 31, 2023		
	Weighted Average Useful Lives	Property, Plant and Equipment, Gross	Accumulated Depreciation & Amortization	Property, Plant and Equipment, Net	Property, Plant and Equipment, Gross	Accumulated Depreciation & Amortization	Property, Plant and Equipment, Net
	(in years)	(in millions)					
CenterPoint Energy							
Electric transmission and distribution	37	$ 21,387	$ 4,810	$ 16,577	$ 19,151	$ 4,762	$ 14,389
Electric generation (1)	25	1,107	154	953	1,381	315	1,066
Natural gas distribution	32	16,399	4,326	12,073	16,492	4,337	12,155
Finance ROU asset (2)	7.5	662	232	430	662	136	526
Other property	22	3,112	1,056	2,056	2,710	993	1,717
Total		$ 42,667	$ 10,578	$ 32,089	$ 40,396	$ 10,543	$ 29,853

	Weighted Average Useful Lives	December 31, 2024			December 31, 2023		
		Property, Plant and Equipment, Gross	Accumulated Depreciation & Amortization	Property, Plant and Equipment, Net	Property, Plant and Equipment, Gross	Accumulated Depreciation & Amortization	Property, Plant and Equipment, Net
	(in years)	(in millions)					
Houston Electric							
Electric transmission and distribution	37	$ 18,645	$ 3,647	$ 14,998	$ 16,800	$ 3,641	$ 13,159
Finance ROU asset (2)	7.5	662	232	430	662	136	526
Other property	20	2,443	749	1,694	2,053	692	1,361
Total		$ 21,750	$ 4,628	$ 17,122	$ 19,515	$ 4,469	$ 15,046
CERC							
Natural gas distribution	32	$ 15,474	$ 4,118	$ 11,356	$ 15,591	$ 4,136	$ 11,455
Other property	11	78	28	50	81	33	48
Total		$ 15,552	$ 4,146	$ 11,406	$ 15,672	$ 4,169	$ 11,503

(1) SIGECO and AGC owned a 300 MW unit at the Warrick Power Plant (Warrick Unit 4) as tenants in common as of December 31, 2023. SIGECO's share of the cost of this unit as of December 31, 2023, was $198 million with accumulated depreciation totaling $171 million. Under the operating agreement, AGC and SIGECO shared equally in the cost of operation and output of the unit. SIGECO's share of operating costs was included in Operation and maintenance expense in CenterPoint Energy's Statements of Consolidated Income. SIGECO exited joint operations of Warrick Unit 4 on January 1, 2024.

(2) Houston Electric recognized a finance ROU asset as of December 31, 2024 and December 31, 2023 related to temporary generation. See Note 19 for further discussion.

(b) Depreciation and Amortization

The following table presents depreciation and amortization expense for 2024, 2023 and 2022:

	Year Ended December 31,								
	2024			2023			2022		
	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC
	(in millions)								
Depreciation	$ 1,177	$ 545	$ 492	$ 1,092	$ 484	$ 459	$ 1,013	$ 434	$ 420
Amortization of securitized regulatory assets	90	74	—	163	155	—	191	191	—
Other amortization	172	143	30	146	109	34	84	45	28
Total	$ 1,439	$ 762	$ 522	$ 1,401	$ 748	$ 493	$ 1,288	$ 670	$ 448

(c) AROs

The Registrants account for an ARO at fair value in the period during which the legal obligation is incurred if a reasonable estimate of fair value and its settlement date can be made. At the timing of recording an ARO, the associated asset retirement costs are capitalized as part of the carrying amount of the related long-lived asset. The Registrants recognize a regulatory asset or liability for the timing differences between the recognition of expenses and costs recovered through the ratemaking process. The estimates of future liabilities are developed using a discounted cash flow model based upon estimates and assumptions of future costs, interest rates, credit-adjusted risk-free rates and the estimated timing of settlement.

The Registrants have recorded AROs associated with the removal of asbestos and asbestos-containing material in its buildings, including substation building structures. CenterPoint Energy recorded AROs relating to the closure of the ash ponds at A.B. Brown and F.B. Culley as well as certain sites in Indiana pursuant to the CCR Legacy Rule; see Note 14(d) for further discussion. CenterPoint Energy and Houston Electric also recorded AROs relating to treated wood poles for electric distribution, distribution transformers containing PCB (also known as Polychlorinated Biphenyl), and underground fuel storage tanks. CenterPoint Energy and CERC also recorded AROs relating to gas pipelines abandoned in place.

A reconciliation of the changes in the ARO liability recorded in Other non-current liabilities on each of the Registrants' respective Consolidated Balance Sheets is as follows:

	December 31, 2024			December 31, 2023		
	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC
	(in millions)					
Beginning balance	$ 590	$ 40	$ 380	$ 610	$ 36	$ 420
Additions	11	—	—	—	—	—
Accretion expense (1)	21	1	16	23	1	16
Revisions in estimates (2)	(34)	(2)	(33)	(43)	3	(56)
Ending balance	$ 588	$ 39	$ 363	$ 590	$ 40	$ 380

(1) Reflected in Regulatory assets on each of the Registrants' respective Consolidated Balance Sheets.

(2) In 2024 and 2023, CenterPoint Energy and CERC reflected a decrease in their respective ARO liability, which was primarily attributable to increases in the long-term interest rates used for discounting in the ARO calculation. In 2024, Houston Electric reflected a decrease in its ARO liability attributable to an increase in discount rates, while in 2023, Houston Electric reflected an increase in its ARO liability attributable to an increase in discount rates and disposal costs.

(4) Held for Sale and Divestitures (CenterPoint Energy and CERC)

Held for Sale. On February 19, 2024, CERC Corp. entered into the LAMS Asset Purchase Agreement, pursuant to which CERC Corp. agreed to sell its Louisiana and Mississippi natural gas LDC businesses. The purchase price for the Louisiana and Mississippi natural gas LDC businesses is $1.2 billion and subject to adjustment as set forth in the LAMS Asset Purchase Agreement, including adjustments based on net working capital, regulatory assets and liabilities and capital expenditures at closing. The completion of the proposed transaction is subject to customary closing conditions, including (i) the expiration or termination of the applicable waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976, as amended, (ii) approval of the LPSC, (iii) approval of the MPSC, (iv) no Material Adverse Effect (as defined in the LAMS Asset Purchase Agreement) having occurred and (v) customary closing conditions regarding the accuracy of the representations and warranties and compliance by the parties with the respective obligations under the LAMS Asset Purchase Agreement. The proposed transaction is not subject to a financing condition and is expected to close by the end of the first quarter of 2025, subject to satisfaction of the foregoing conditions. The businesses include approximately 12,000 miles of main pipeline in Louisiana and Mississippi serving more than 300,000 customers. The Louisiana and Mississippi natural gas LDC businesses are reflected in CenterPoint Energy's Natural Gas reportable segment and CERC's single reportable segment, as applicable. The transaction was approved by final orders issued by the MPSC on December 3, 2024 and the LPSC on December 17, 2024.

In February 2024, certain assets and liabilities representing the Louisiana and Mississippi natural gas LDC businesses met the held for sale criteria. The sale will be considered an asset sale for tax purposes, requiring net deferred tax liabilities to be excluded from held for sale balances.

The Registrants record assets and liabilities held for sale at the lower of their carrying value or their estimated fair value less cost to sell. Neither CenterPoint Energy nor CERC recognized any gains or losses upon classification of held for sale during the year ended December 31, 2024. If a disposal group reflects a component of a reporting unit and meets the definition of a business, the goodwill within that reporting unit is allocated to the disposal group based on the relative fair value of the components representing a business that will be retained and disposed. See Note 6 for further disclosure regarding the amount of goodwill allocated to the businesses to be sold.

The assets and liabilities of the Louisiana and Mississippi natural gas LDC businesses classified as held for sale in CenterPoint Energy's and CERC's Condensed Consolidated Balance Sheets, as applicable, included the following:

	December 31, 2024	
	CenterPoint Energy	CERC
	(in millions)	
Accounts receivable, net	$ 27	$ 27
Accrued unbilled revenues	26	26
Materials and supplies	13	13
Natural gas inventory	5	5
Property, plant and equipment, net	1,052	1,052
Goodwill	217	122
Regulatory assets	15	15
Other	6	6
Total current assets held for sale	$ 1,361	$ 1,266
Short-term borrowings	$ 3	$ 3
Accounts payable	44	44
Customer deposits	14	14
Regulatory liabilities	31	31
Other	84	84
Total current liabilities held for sale	$ 176	$ 176

Although the Louisiana and Mississippi natural gas LDC businesses meet the held for sale criteria, their proposed disposals do not represent a strategic shift for CenterPoint Energy and CERC as both will retain significant operations in, and will continue to invest in, their natural gas businesses. Therefore, the assets and liabilities associated with these transactions are not reflected as discontinued operations on CenterPoint Energy's and CERC's Condensed Statements of Consolidated Income, as applicable, and the December 31, 2023 Condensed Consolidated Balance Sheets were not required to be recast for assets held for sale. Since the depreciation on the Louisiana and Mississippi natural gas LDC businesses assets will continue to be reflected in revenues through customer rates until the expected closing of the transaction and will be reflected in the carryover basis of the rate-regulated assets once sold, CenterPoint Energy and CERC will continue to record depreciation on those assets through the expected closing of the transaction.

The pre-tax income for the Louisiana and Mississippi natural gas LDC businesses, excluding interest and corporate allocations, included in CenterPoint Energy's and CERC's Statements of Consolidated Income is as follows:

	Year Ended December 31,		
	2024	2023	2022
		(in millions)	
Income Before Income Taxes	$ 67	$ 44	$ 42

Divestiture of Energy Systems Group. On May 21, 2023, CenterPoint Energy, through its subsidiary Vectren Energy Services, entered into an Equity Purchase Agreement to sell all of the outstanding limited liability company interests of Energy Systems Group to ESG Holdings Group, for a purchase price of $157 million, subject to customary adjustments set forth in the Equity Purchase Agreement, including adjustments based on Energy Systems Group's net working capital at closing, indebtedness, cash and cash equivalents and transaction expenses. The transaction closed on June 30, 2023, and CenterPoint Energy received $154 million in cash. In November 2024, CenterPoint Energy paid $2 million to ESG Holdings Group for working capital and other adjustments set forth in the Equity Purchase Agreement. For a discussion of CenterPoint Energy's pre-disposition guarantees related to Energy Systems Group, see Note 14(c).

CenterPoint Energy recognized a loss on sale of approximately $13 million, including $3 million of transaction costs, during the year ended December 31, 2023, in connection with the closing of the sale of Energy Systems Group. Additionally, CenterPoint Energy recognized a current tax expense of $32 million during the year ended December 31, 2023, as a result of the cash taxes payable upon the closing of the sale.

The pre-tax income (loss) for Energy Systems Group, excluding interest and corporate allocations, included in CenterPoint Energy's Statements of Consolidated Income is as follows:

	Year Ended December 31,	
	2023 (1)	2022
	(in millions)	
Income (Loss) Before Income Taxes	$ (4)	$ 2

(1) Reflects January 1, 2023 to June 30, 2023 results only due to of the sale of Energy Systems Group.

Divestiture of Arkansas and Oklahoma Natural Gas Businesses (CenterPoint Energy and CERC). On April 29, 2021, CenterPoint Energy, through its subsidiary CERC Corp., entered into the AROK Asset Purchase Agreement to sell its Arkansas and Oklahoma Natural Gas businesses for $2.15 billion in cash, including recovery of approximately $425 million in natural gas costs, including storm-related incremental natural gas costs associated with the February 2021 Winter Storm Event, subject to certain adjustments set forth in the AROK Asset Purchase Agreement. The assets included approximately 17,000 miles of main pipeline in Arkansas, Oklahoma and certain portions of Bowie County, Texas serving more than half a million customers. The transaction closed on January 10, 2022.

The sale was considered an asset sale for tax purposes, requiring net deferred tax liabilities to be excluded from held for sale balances. The deferred taxes associated with the businesses were recognized as a deferred income tax benefit by CenterPoint Energy and CERC upon closing of the sale in 2022.

CenterPoint Energy and CERC recognized gains of $303 million and $557 million, respectively, net of transaction costs of $59 million, in connection with the closing of the disposition of the Arkansas and Oklahoma Natural Gas businesses during the year ended December 31, 2022. CenterPoint Energy and CERC collected a receivable of $15 million in May 2022 for full and final settlement of the working capital adjustment under the AROK Asset Purchase Agreement.

The pre-tax income for the Arkansas and Oklahoma Natural Gas businesses, excluding interest and corporate allocations, included in CenterPoint Energy's and CERC's Statements of Consolidated Income was $9 million for the year ended December 31, 2022, which only reflects January 1, 2022 to January 9, 2022 results due to the sale of the Arkansas and Oklahoma Natural Gas businesses previously described.

Effective on the date of the closing of the disposition of the Arkansas and Oklahoma Natural Gas businesses, a subsidiary of CenterPoint Energy entered into the Transition Services Agreement, whereby that subsidiary agreed to provide certain transition services such as accounting, customer operations, procurement, and technology functions for a term of up to twelve months. In November 2022, a significant majority of all services under the Transition Services Agreement were terminated, and on January 10, 2023, all remaining services were terminated.

CenterPoint Energy's charges to Southern Col Midco for reimbursement of transition services was less than $1 million and $40 million during the years ended December 31, 2023 and 2022, respectively. Actual transition services costs incurred are recorded net of amounts charged to Southern Col Midco. CenterPoint Energy had no accounts receivable as of December 31, 2023 from Southern Col Midco for transition services.

(5) Revenue Recognition

In accordance with ASC 606, Revenue from Contracts with Customers, revenue is recognized when a customer obtains control of promised goods or services. The amount of revenue recognized reflects the consideration to which the Registrants expect to be entitled to receive in exchange for these goods or services.

ARPs are contracts between the utility and its regulators, not between the utility and a customer. The Registrants recognize ARP revenue as other revenues when the regulator-specified conditions for recognition have been met. Upon recovery of ARP revenue through incorporation in rates charged for utility service to customers, ARP revenue is reversed and recorded as revenue from contracts with customers. The recognition of ARP revenues and the reversal of ARP revenues upon recovery through rates charged for utility service may not occur in the same period.

The following tables disaggregate revenues by reportable segment and major source:

CenterPoint Energy

	Year Ended December 31, 2024			
	Electric	Natural Gas	Corporate and Other	Total
	(in millions)			
Revenue from contracts with customers	$ 4,558	$ 3,990	$ 4	$ 8,552
Other (1)	32	58	3	93
Eliminations	—	(2)	—	(2)
Total revenues	$ 4,590	$ 4,046	$ 7	$ 8,643

	Year Ended December 31, 2023			
	Electric	Natural Gas	Corporate and Other	Total
	(in millions)			
Revenue from contracts with customers	$ 4,275	$ 4,210	$ 127	$ 8,612
Other (1)	15	69	3	87
Eliminations	—	(3)	—	(3)
Total revenues	$ 4,290	$ 4,276	$ 130	$ 8,696

	Year Ended December 31, 2022			
	Electric	Natural Gas	Corporate and Other	Total
	(in millions)			
Revenue from contracts with customers	$ 4,095	$ 4,969	$ 263	$ 9,327
Other (1)	13	(23)	4	(6)
Total revenues	$ 4,108	$ 4,946	$ 267	$ 9,321

(1) Primarily consists of income from ARPs and leases.

Houston Electric

	Year Ended December 31,		
	2024	2023	2022
	(in millions)		
Revenue from contracts with customers	$ 3,930	$ 3,684	$ 3,417
Other (1)	9	(7)	(5)
Total revenues	$ 3,939	$ 3,677	$ 3,412

(1) Primarily consists of income from ARPs and leases.

CERC

	Year Ended December 31,		
	2024	2023	2022
	(in millions)		
Revenue from contracts with customers	$ 3,868	$ 4,083	$ 4,816
Other (1)	57	66	(16)
Total revenues	$ 3,925	$ 4,149	$ 4,800

(1) Primarily consists of income from ARPs and leases.

Revenues from Contracts with Customers

Electric (CenterPoint Energy and Houston Electric). Houston Electric distributes electricity to customers over time and customers consume the electricity when delivered. Indiana Electric generates, distributes and transmits electricity to customers over time and customers consume the electricity when delivered. Revenue, consisting of both volumetric and fixed tariff rates set by state regulators, such as the PUCT and the IURC, is recognized as electricity is delivered and represents amounts both billed and unbilled. Discretionary services requested by customers are provided at a point in time with control transferring upon the completion of the service. Revenue for discretionary services provided by Houston Electric is recognized upon completion of service based on the tariff rates set by the PUCT. Payments for electricity distribution and discretionary services are aggregated and received on a monthly basis. Houston Electric performs transmission services over time as a stand-ready obligation to provide a reliable network of transmission systems. Revenue is recognized upon time elapsed and the monthly tariff rate set by the regulator. Payments are received on a monthly basis. Indiana Electric customers are billed monthly and payment terms, set by the regulator, require payment within a month of billing.

Natural Gas (CenterPoint Energy and CERC). CenterPoint Energy and CERC distribute and transport natural gas to customers over time and customers consume the natural gas when delivered. Revenue, consisting of both volumetric and fixed tariff rates set by the state governing agency for that service area, is recognized as natural gas is delivered and represents amounts both billed and unbilled. Discretionary services requested by the customer are provided at a point in time with control transferring upon completion of the service. Revenue for discretionary services is recognized upon completion of service based on the tariff rates set by the applicable state regulator. Payments of natural gas distribution, transportation and discretionary services are aggregated and received on a monthly basis.

Contract Balances. When the timing of delivery of service is different from the timing of the payments made by customers and when the right to consideration is conditioned on something other than the passage of time, the Registrants recognize a contract liability when customer payment precedes performance. Those customers that prepay are represented by contract liabilities until the performance obligations are satisfied. The Registrants' contract liabilities are included in Accounts payable and Other current liabilities in their Consolidated Balance Sheets.

The opening and closing balances of accounts receivable, accrued unbilled revenues and contract liabilities from contracts with customers are as follows:

CenterPoint Energy

	Accounts Receivable	Accrued Unbilled Revenues	Contract Liabilities
		(in millions)	
Opening balance as of December 31, 2023	$ 652	$ 516	$ 2
Closing balance as of December 31, 2024	666	521	2
Increase	$ 14	$ 5	$ —

The amount of revenue recognized in the year ended December 31, 2024 that was included in the opening contract liability was $2 million. The difference between the opening and closing balances of the contract liabilities primarily results from the timing difference between CenterPoint Energy's performance and the customer's payment.

Houston Electric

	Accounts Receivable	Accrued Unbilled Revenues	Contract Liabilities
		(in millions)	
Opening balance as of December 31, 2023	$ 275	$ 142	$ 2
Closing balance as of December 31, 2024	284	137	2
Increase (decrease)	$ 9	$ (5)	$ —

The amount of revenue recognized in the year ended December 31, 2024 that was included in the opening contract liability was $2 million. The difference between the opening and closing balances of the contract liabilities primarily results from the timing difference between Houston Electric's performance and the customer's payment.

CERC

	Accounts Receivable	Accrued Unbilled Revenues
	(in millions)	
Opening balance as of December 31, 2023	$ 330	$ 329
Closing balance as of December 31, 2024	326	338
Increase (decrease)	$ (4)	$ 9

CERC does not have any opening or closing contract asset or contract liability balances.

Practical Expedients and Exemption. Sales taxes and other similar taxes collected from customers are excluded from the transaction price. For contracts for which revenue from the satisfaction of the performance obligations is recognized in the amount invoiced, the practical expedient was elected and revenue expected to be recognized on these contracts has not been disclosed.

Allowance for Credit Losses and Bad Debt Expense

CenterPoint Energy and CERC segregate financial assets that fall under the scope of ASU 2016-13, Financial Instruments - Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments, primarily trade receivables due in one year or less, into portfolio segments based on shared risk characteristics, such as geographical location and regulatory environment, for evaluation of expected credit losses. Historical and current information, such as average write-offs, are applied to each portfolio segment to estimate the allowance for losses on uncollectible receivables. Additionally, the allowance for losses on uncollectible receivables is adjusted for reasonable and supportable forecasts of future economic conditions, which can include changing weather, commodity prices, regulations and macroeconomic factors, among others. Houston Electric had no material changes in its methodology to recognize losses on financial assets that fall under the scope of Topic 326, primarily due to the nature of its customers and regulatory environment. For a discussion of regulatory deferrals, see Note 7.

The table below summarizes the Registrants' bad debt expense amounts for 2024, 2023 and 2022, net of regulatory deferrals:

	Year Ended December 31,								
	2024			2023			2022		
	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC
	(in millions)								
Bad debt expense	$ 21	$ 1	$ 16	$ 18	$ —	$ 16	$ 20	$ —	$ 17

(6) Goodwill (CenterPoint Energy and CERC)

CenterPoint Energy's goodwill by reportable segment is as follows for the periods presented:

	Electric (1)	Natural Gas	Corporate and Other	Total
		(in millions)		
Balance at December 31, 2022	$ 936	$ 2,920	$ 438	$ 4,294
Disposal (2)	—	—	134	134
Balance at December 31, 2023	936	2,920	304	4,160
Held for Sale (3)	—	217	—	217
Balance at December 31, 2024	$ 936	$ 2,703	$ 304	$ 3,943

(1) Balances are presented net of the accumulated goodwill impairment charge of $185 million recorded in 2020.
(2) Represents goodwill attributable to the sale of Energy Systems Group. For further information, see Note 4.
(3) Represents goodwill attributable to the Louisiana and Mississippi natural gas LDC businesses classified as held for sale as of December 31, 2024. CenterPoint Energy did not recognize any goodwill impairments within the Natural Gas reportable segment for the year ended December 31, 2024. For further information, see Note 4.

There were no events impacting CERC's goodwill for the year ended December 31, 2023. CERC's goodwill is as follows for the periods presented:

	December 31, 2023	Held for Sale (1)	December 31, 2024
		(in millions)	
Goodwill	$ 1,583	$ 122	$ 1,461

(1) Represents goodwill attributable to CERC to be disposed of as part of the potential sale of the Louisiana and Mississippi natural gas LDC businesses was classified as held for sale as of December 31, 2024. CERC did not recognize any goodwill impairments during the year ended December 31, 2024. For further information, see Note 4.

CenterPoint Energy and CERC performed their annual goodwill impairment tests in the third quarter of each of 2024 and 2023 and determined that no goodwill impairment charge was required for any reporting unit as a result of those tests.

(7) Regulatory Matters

The following is a list of regulatory assets and liabilities reflected on the Registrants' respective Consolidated Balance Sheets as of December 31, 2024 and 2023:

	December 31, 2024		
	CenterPoint Energy	Houston Electric	CERC
		(in millions)	
Regulatory Assets:			
Future amounts recoverable from ratepayers related to:			
Benefit obligations (1)	$ 373	$ —	$ 4
Asset retirement obligations & other	304	80	188
Net deferred income taxes	144	47	69
Total future amounts recoverable from ratepayers	821	127	261
Amounts deferred for future recovery related to:			
Cost recovery riders	145	—	83
Hurricanes and February 2021 Winter Storm Event Restoration Costs	145	145	—
May 2024 Storm Events	86	86	—
Hurricane Beryl	458	458	—
Hurricane Francine	19	19	—
Other regulatory assets	177	87	74
Decoupling	12	—	12
Temporary generation costs	71	71	—
Unrecognized equity return (2)	(115)	(77)	(30)
Total amounts deferred for future recovery	998	789	139
Amounts currently recovered in customer rates related to:			
Authorized trackers and cost deferrals	600	47	440
Securitized regulatory assets	343	—	—
Unamortized loss on reacquired debt and hedging	93	63	10
Gas recovery costs	122	—	122
Decoupling	38	—	38
Extraordinary gas costs	133	—	133
Regulatory assets related to TCJA	47	47	—
Hurricanes and February 2021 Winter Storm Event Restoration Costs	31	5	26
Other regulatory assets	34	—	34
Benefit obligations	4	4	—
Temporary generation costs	219	219	—
Unrecognized equity return (3)	(136)	(17)	(62)
Total amounts recovered in customer rates (5)	1,528	368	741
Total Regulatory Assets	$ 3,347	$ 1,284	$ 1,141
Total Current Regulatory Assets	$ 239	$ —	$ 238
Total Non-Current Regulatory Assets	$ 3,108	$ 1,284	$ 903
Regulatory Liabilities:			
Regulatory liabilities related to TCJA	$ 1,346	$ 673	$ 501
Estimated removal costs	1,247	—	1,191
Other regulatory liabilities	454	195	235
Total Regulatory Liabilities	$ 3,047	$ 868	$ 1,927
Total Current Regulatory Liabilities (6)	$ 48	$ 7	$ 40
Total Non-Current Regulatory Liabilities	$ 2,999	$ 861	$ 1,887

	December 31, 2023		
	CenterPoint Energy	Houston Electric	CERC
		(in millions)	
Regulatory Assets:			
Future amounts recoverable from ratepayers related to:			
Benefit obligations (1)	$ 379	$ —	$ 5
Asset retirement obligations & other	290	75	186
Net deferred income taxes	96	41	42
Total future amounts recoverable from ratepayers	765	116	233
Amounts deferred for future recovery related to:			
Cost recovery riders	113	—	73
Hurricanes and February 2021 Winter Storm Event restoration costs	149	123	26
Other regulatory assets	147	59	72
Gas recovery costs	27	—	27
Decoupling	17	—	17
COVID-19 incremental costs	12	8	4
Temporary generation costs	48	48	—
Unrecognized equity return (2)	(63)	(39)	(16)
Total amounts deferred for future recovery	450	199	203
Amounts currently recovered in customer rates related to:			
Authorized trackers and cost deferrals	535	44	375
Securitized regulatory assets	434	74	—
Unamortized loss on reacquired debt and hedging	106	72	11
Gas recovery costs	34	—	34
Extraordinary gas costs	208	—	208
Regulatory assets related to TCJA	47	47	—
Hurricane Harvey restoration costs	17	17	—
Benefit obligations	11	11	—
Temporary generation costs	208	208	—
Unrecognized equity return (4)	(141)	(36)	(53)
Total amounts recovered in customer rates	1,459	437	575
Total Regulatory Assets	$ 2,674	$ 752	$ 1,011
Total Current Regulatory Assets	$ 161	$ —	$ 161
Total Non-Current Regulatory Assets	$ 2,513	$ 752	$ 850
Regulatory Liabilities:			
Regulatory liabilities related to TCJA	$ 1,377	$ 695	$ 505
Estimated removal costs	1,322	91	1,150
Other regulatory liabilities	548	245	260
Total Regulatory Liabilities	$ 3,247	$ 1,031	$ 1,915
Total Current Regulatory Liabilities (6)	$ 39	$ 6	$ 33
Total Non-Current Regulatory Liabilities	$ 3,208	$ 1,025	$ 1,882

(1) Pension and postretirement-related regulatory assets balances are actuarially valued annually.

(2) Represents the following: (a) CenterPoint Energy's allowed equity return on post in-service carrying cost generally associated with investments in Indiana; (b) Houston Electric's allowed equity return on TEEEF costs and storm restoration costs; and (c) CERC's allowed equity return on post in-service carrying cost associated with certain distribution facilities replacements expenditures in Texas.

(3) Represents the following: (a) CenterPoint Energy's allowed equity return on post in-service carrying cost generally associated with investments in Indiana; (b) Houston Electric's allowed equity return on certain storm restoration balances and (c) CERC's allowed equity return on post in-service carrying cost associated with certain distribution facilities replacements expenditures in Texas.

(4) Represents the following: (a) CenterPoint Energy's allowed equity return on post in-service carrying cost generally associated with investments in Indiana; (b) Houston Electric's allowed equity return on its true-up balance of stranded costs, other changes and related interest resulting from the formerly integrated electric utilities prior to Texas

deregulation to be recovered in rates through 2024 and certain storm restoration balances; and (c) CERC's allowed equity return on post in-service carrying cost associated with certain distribution facilities replacements expenditures in Texas.

(5) Of the $1.5 billion, $368 million and $741 million currently being recovered in customer rates related to CenterPoint Energy, Houston Electric and CERC, respectively, $463 million, $305 million and $158 million is earning a return, respectively. The weighted average recovery period of regulatory assets currently being recovered in base rates, not earning a return, which totals $424 million, $63 million and $328 million for CenterPoint Energy, Houston Electric and CERC, respectively, is 11 years, 27 years and 7 years, respectively. Regulatory assets not earning a return with perpetual or undeterminable lives have been excluded from the weighted average recovery period calculation.

(6) Current regulatory liabilities are included in Other current liabilities in each of the Registrants' respective Consolidated Balance Sheets.

The table below reflects the amount of allowed equity return recognized by each Registrant in its Statements of Consolidated Income for the periods presented:

	Year Ended December 31,								
	2024			2023			2022		
	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC
	(in millions)								
Allowed equity return recognized	$ 23	$ 20	$ 2	$ 41	$ 38	$ 2	$ 45	$ 42	$ 2

February 2021 Winter Storm Event

In February 2021, certain of the Registrants' jurisdictions experienced an extreme and unprecedented winter weather event that resulted in prolonged freezing temperatures, which impacted their businesses. The February 2021 Winter Storm Event impacted wholesale prices of CenterPoint Energy's and CERC's natural gas purchases and their ability to serve customers in their Natural Gas service territories, including due to the reduction in available natural gas capacity and impacts to CenterPoint Energy's and CERC's natural gas supply portfolio activities, and the effects of weather on their systems and their ability to transport natural gas, among other things. The overall natural gas market, including the markets from which CenterPoint Energy and CERC sourced a significant portion of their natural gas for their operations, experienced significant impacts caused by the February 2021 Winter Storm Event, resulting in extraordinary increases in the cost of natural gas purchased by CenterPoint Energy and CERC of approximately $2 billion. CenterPoint Energy and CERC have completed recovery of natural gas costs in Mississippi, Indiana, Louisiana and Texas, and continue to recover the natural gas cost in Minnesota. As of December 31, 2024, CenterPoint Energy and CERC had each recorded current regulatory assets of $67 million and non-current regulatory assets of $67 million associated with the February 2021 Winter Storm Event. As of December 31, 2023, CenterPoint Energy and CERC have each recorded current regulatory assets of $86 million and non-current regulatory assets of $130 million associated with the February 2021 Winter Storm Event.

In Minnesota, the MPUC issued its written order on October 19, 2022 disallowing CERC's recovery of approximately $36 million of the $409 million incurred, and CERC's regulatory asset balance was reduced to reflect the disallowance. CERC filed a petition for reconsideration on November 8, 2022 and a written order denying the petition for reconsideration was issued on January 6, 2023.

As of December 31, 2024 and 2023, as authorized by the PUCT, both CenterPoint Energy and Houston Electric had each recorded a regulatory asset of $8 million for bad debt expenses resulting from REPs' default on their obligation to pay delivery charges to Houston Electric net of collateral. Additionally, both CenterPoint Energy and Houston Electric had each recorded a regulatory asset of $19 million and $17 million as of December 31, 2024 and 2023, respectively, and requested reimbursement of costs associated with the February 2021 Winter Storm Event in Houston Electric's rate case, which was filed in March 2024. On January 29, 2025 Houston Electric announced that a settlement agreement was reached with certain parties to the rate case filed on March 6, 2024, including the City of Houston and other regional municipalities. Subject to PUCT review and approval, the settlement is expected to result in approximately $50 million less annual revenue and an average decrease of approximately $1 a month for residential customers based on average usage of 1,000 kWh per month.

See Note 14(d) for further information regarding litigation related to the February 2021 Winter Storm Event.

Texas Public Securitization

The Texas Natural Gas Securitization Finance Corporation issued customer rate relief bonds in March 2023, and on March 23, 2023, CenterPoint Energy and CERC, collectively, received approximately $1.1 billion in cash proceeds from the issuance and sale of the state's customer rate relief bonds. The proceeds from the state's customer rate relief bonds included carrying costs incurred through August 2022. Incremental carrying costs incurred after August 2022 until the date the proceeds were received are recorded in a separate regulatory asset; the most recent CERC rate proceeding in Texas included a request for recovery of this regulatory asset and was included in the settlement agreement approved by the Railroad Commission in June 2024. As CenterPoint Energy and CERC have no future financial obligations for the repayment of the state's customer rate relief bonds, the customer rate relief bonds are not recorded on CenterPoint Energy's or CERC's balance sheets. The state's customer rate relief bonds are backed in part by customer rate relief property, including customer rate relief charges, which are non-bypassable uniform monthly volumetric charges to be paid by all existing and future sales customers as a component of each regulated utility's gas cost, separate from their base rate. CERC only acts as a collection agent, whose duties include management, servicing and administration of a portion of the customer rate relief property which is associated with the customer rate relief charge imposed on customers of CERC under the guidance and direction from the Railroad Commission. The Texas Natural Gas Securitization Finance Corporation, and not CenterPoint Energy or CERC, is the owner of the customer rate relief property. The assets of the Texas Natural Gas Securitization Finance Corporation are not available to pay creditors of CenterPoint Energy, CERC, or their affiliates. While the customer rate relief charges will be included by CERC in their monthly billings, the billing amount is established by the Railroad Commission. CERC will remit all customer rate relief charges collected to the financing entity set up by the Railroad Commission. Therefore, the collection and servicing of customer rate relief charges have no impact on the respective Statements of Consolidated Income of CenterPoint Energy or CERC.

As U.S. GAAP has no specific accounting guidance for government grants or assistance, the cash proceeds from the state's customer rate relief bonds were accounted for as a government grant by analogy to the grant model under IAS 20—Accounting for Government Grants and Disclosures of Government Assistance. CenterPoint Energy and CERC reflect the proceeds from the grant as a deduction to natural gas costs and recognized the $1.1 billion of cash proceeds from the state's customer rate relief bonds within Utility natural gas expense on their respective Statements of Consolidated Income in the year ended December 31, 2023, net of the recognition of natural gas cost related to relieving CenterPoint Energy and CERC's regulatory assets related to the February 2021 Winter Storm Event in the same period.

Indiana Electric Securitization of Generation Retirements (CenterPoint Energy)

On January 4, 2023, the IURC issued an order in accordance with Indiana Senate Enrolled Act 386 authorizing the issuance of up to $350 million in securitization bonds to securitize qualified costs associated with the retirements of Indiana Electric's A.B. Brown coal-fired generation facilities. Accordingly, CenterPoint Energy determined that the retirement of property, plant and equipment became probable upon the issuance of the order. No loss on abandonment was recognized in connection with issuance of the order as there was no disallowance of all or part of the cost of the abandoned property, plant and equipment. In the first quarter of 2023, upon receipt of the order, CenterPoint Energy reclassified property, plant and equipment to be recovered through securitization to a regulatory asset and such amounts continued to earn a full return until recovered through securitization.

The SIGECO Securitization Subsidiary issued $341 million aggregate principal amount of the SIGECO Securitization Bonds on June 29, 2023. The SIGECO Securitization Subsidiary used a portion of the net proceeds from the issuance of the SIGECO Securitization Bonds to purchase the securitization property from SIGECO. No gain or loss was recognized.

The SIGECO Securitization Bonds are secured by the securitization property, which includes the right to recover, through non-bypassable securitization charges payable by SIGECO's retail electric customers, the qualified costs of SIGECO authorized by the IURC order. The SIGECO Securitization Subsidiary, and not SIGECO, is the owner of the securitization property, and the assets of the SIGECO Securitization Subsidiary are not available to pay the creditors of SIGECO or its affiliates, other than the SIGECO Securitization Subsidiary. SIGECO has no payment obligations with respect to the SIGECO Securitization Bonds except to remit collections of securitization charges as set forth in a servicing agreement between SIGECO and the SIGECO Securitization Subsidiary. The non-bypassable securitization charges are subject to a true-up mechanism.

Houston Electric TEEEF

Pursuant to legislation passed in 2021, Houston Electric entered into two leases for TEEEF (temporary generation) which are detailed in Note 19. Houston Electric initially sought recovery of the lease costs and the applicable return as of December 31, 2021 under these lease agreements of approximately $200 million in its DCRF application filed with the PUCT on April 5,

2022, and subsequently amended on July 1, 2022, to show temporary generation in a separate Rider TEEEF. A final order was issued on April 5, 2023 approving a revenue requirement of $39 million that results in full recovery of costs requested but lengthens the amortization period for the short-term lease to be collected over 82.5 months. On May 25, 2023, the PUCT issued its order on rehearing which clarified some of the findings but did not change the approval of TEEEF cost recovery. The PUCT's decision on the first TEEEF filing is now final and non-appealable.

On April 5, 2023, Houston Electric made its second TEEEF filing requesting recovery of TEEEF related costs incurred through December 31, 2022, which requested a new annual revenue requirement of approximately $188 million using 78 months to amortize the related deferred costs for proposed rates beginning September 2023, a net increase in TEEEF revenues of approximately $149 million. On August 28, 2023, the State Office of Administrative Hearings issued an Order setting interim rates to collect an annual revenue requirement at the filed amount. Interim rates became effective on September 1, 2023, subject to surcharge or refund if they differ from the final rates approved by the PUCT. An agreement in principle was reached which reduced the annual revenue requirement by approximately $35 million based on recovering the balance as of December 31, 2022 over a 102-month amortization period (instead of the 78-month period in the initial filing) and also allowed for revised interim rates (to incorporate the agreement in principle and the initial interim rates that have been in place since September 1, 2023). The updated interim rates were implemented on December 15, 2023 and approved by the PUCT pursuant to its order issued on February 1, 2024 when the PUCT approved the agreement in principle. The PUCT's decision on the second TEEEF filing is final and non-appealable.

On September 11, 2024, the TCA filed a complaint with the PUCT requesting that the PUCT modify its rulings with respect to its prior decisions related to the TEEEF filings made in 2022 and 2023. Specifically, TCA requested that the PUCT end cost recovery and return on investment on all the large 32 MW and 5 MW TEEEF units approved in docket 53442. On October 2, 2024, Houston Electric filed a response to the TCA complaint and requested that the complaint be dismissed due to the principles of *res judicata* and collateral estoppel. On October 8, 2024, TCA supplemented its complaint and on October 9, 2024, PUCT staff filed a statement of position stating that Houston Electric's response provided a strong argument for dismissal of the complaint, but also stating that it would be prudent to have a thorough legal argument from TCA. On October 10, 2024, PUCT issued Order No. 2 finding the TCA complaint insufficient and requiring supplemental information or amendment from TCA by October 24, 2024; TCA filed supplemental information on October 24, 2024. On November 14, 2024, PUCT issued Order No. 4 denying the motion to reconsider and extending a deadline. On December 16, 2024, PUCT issued Order No. 5 granting waiver of the requirement for informal disposition and soliciting commission staff recommendation by January 16, 2025. On January 16, 2025, PUCT staff filed a supplemental recommendation recommending that the TCA has not met its requirement to first present its complaint to the City of Houston prior to presenting it to the PUCT. On January 17, 2025 the case was abated until February 28, 2025 to enable the TCA to present its complaint to the City of Houston.

On December 19, 2024, Houston Electric announced a proposal to release Houston Electric's 15 large 27 MW to 32 MW TEEEF units to the San Antonio area prior to the summer of 2025. The proposal is intended to help ERCOT address a potential energy shortfall and Load Shed risk and to provide additional electric generation capacity to support growing energy demand in the greater San Antonio region. Under the proposal, Houston Electric would not receive revenue or profit from ERCOT and would also not charge Houston-area customers for these TEEEF units for the period when they are in San Antonio serving ERCOT, which is currently expected to be for a period of up to two years. Houston Electric would anticipate receiving revenues from one or more future transactions after the period the units are utilized to temporarily serve an energy need in the San Antonio area, and would therefore plan to continue to not charge customers for these units for any future periods. The proposal has not been finalized and is subject to the negotiation of definitive documentation among the relevant parties, as well as being subject to the approval of ERCOT and other stakeholders. It is not certain that mutually agreeable definitive documentation will be entered into at all or that all approvals will be obtained.

Houston Electric defers costs associated with the short-term and long-term leases that are probable of recovery and would otherwise be charged to expense in a regulatory asset, including allowed debt returns, and determined that such regulatory assets remain probable of recovery as of December 31, 2024. Right of use finance lease assets, such as assets acquired under the long-term leases, are evaluated for impairment under the long-lived asset impairment model by assessing if a capital disallowance from a regulator is probable through monitoring the outcome of rate cases and other proceedings. Houston Electric did not record any impairments on its right of use assets or regulatory asset in the years ended December 31, 2024 and 2023. See Note 19 for further information.

May 2024 Storm Events

Houston Electric's service territory experienced sudden and destructive severe weather events in May 2024 that included hurricane-like winds and tornadoes. The May 2024 Storm Events caused significant damage to Houston Electric's electric

delivery system. As of December 31, 2024, Houston Electric had recorded $345 million in Property, plant and equipment and $73 million in Regulatory assets, excluding carrying costs, for such restoration costs. Based on currently available information, as of December 31, 2024, Houston Electric estimates that total costs to restore the electric delivery facilities damaged as a result of the May 2024 Storm Events will be approximately $458 million, excluding carrying costs. These preliminary estimates are subject to revision as certain restoration costs are expected to be incurred through the end of 2025.

As is common with electric utilities serving coastal regions, the poles, towers, wires, street lights and pole-mounted equipment that comprise Houston Electric's transmission and distribution system are not covered by property insurance. Houston Electric is deferring certain storm restoration costs as management believes it is probable that such costs will be recovered through the regulatory process. On November 8, 2024, Houston Electric filed an Application for Determination of System Restoration Costs with the PUCT. The application seeks a determination as to the reasonableness and necessity of approximately $502 million of costs (including estimated case processing expenses and carrying costs) incurred or expected to be incurred to restore service following the May 2024 Storm Events. On January 10, 2025, intervenors filed testimony recommending various disallowances ranging from $4.1 million to $101.9 million. On January 17, 2025, PUCT staff filed testimony recommending no adjustments to Houston Electric's request. Houston Electric's rebuttal testimony was filed January 21, 2025. On January 29, 2025, the parties represented to the ALJ that a settlement in principle had been reached and requested an abatement to memorialize and finalize the settlement. The case was abated and parties will file finalized settlement documents or a status update by February 26, 2025. Prior to authorizing Houston Electric to recover these costs, the PUCT must first determine the amount of reasonable and necessary system restoration costs. On January 24, 2025, Houston Electric filed a request for a Financing Order for the distribution costs included in the November 8, 2024 Application for Determination of System Restoration Costs. The ultimate recovery of the costs (or a portion thereof) is expected to be sought through the issuance and sale of non-recourse securitization bonds for distribution-related costs and the TCOS capital mechanism for transmission-related costs. However, neither the amount nor timing of the recovery is certain.

See Note 12 for further information regarding a term loan facility to fund certain costs related to the May 2024 Storm Events.

Hurricane Beryl

On July 8, 2024, Hurricane Beryl made landfall in Texas, bringing sustained winds, storm surges and torrential rain into Houston Electric's service territory. Hurricane Beryl caused significant damage to Houston Electric's electric delivery system. Based on currently available information, as of December 31, 2024, Houston Electric estimates that total costs to restore the electric delivery facilities damaged as a result of Hurricane Beryl will be approximately $1.1 billion, excluding carrying costs. As of December 31, 2024, Houston Electric had recorded $654 million in Property, plant and equipment and $442 million in Regulatory assets, excluding carrying costs, for such restoration costs.

Houston Electric is deferring certain storm restoration costs as management believes it is probable that such costs will be recovered through the regulatory process. Similar to the costs related to the May 2024 Storm Events, insurance coverage was not available for damages to much of our transmission and distribution assets. The ultimate recovery of the costs (or a portion thereof) relating to Hurricane Beryl is expected to be sought through the issuance and sale of non-recourse securitization bonds for distribution-related costs. However, neither the amount nor timing of the recovery is certain.

(8) Stock-Based Incentive Compensation Plans and Employee Benefit Plans

(a) Stock-Based Incentive Compensation Plans (CenterPoint Energy)

CenterPoint Energy has LTIPs that provide for the issuance of stock-based incentives, including stock options, performance awards, restricted stock unit awards and restricted and unrestricted stock awards to officers, employees and non-employee directors. Approximately 30 million shares of Common Stock are authorized under these plans for awards. CenterPoint Energy issues new shares of its Common Stock to satisfy stock-based payments related to LTIPs. Equity awards are granted to employees without cost to the participants.

Compensation costs for the performance awards and stock unit awards granted under LTIPs are measured using fair value and expected achievement levels on the grant date. For performance awards with operational goals, the achievement levels are revised as goals are evaluated. The fair value of awards granted to employees is based on the closing stock price of CenterPoint Energy's Common Stock on the grant date. The compensation expense is recorded on a straight-line basis over the vesting period. Forfeitures are estimated on the date of grant based on historical averages and estimates are updated periodically throughout the vesting period.

The performance awards granted in 2024, 2023 and 2022 are distributed based upon the achievement of certain performance conditions or market conditions over a three-year performance cycle. The performance conditions are based on CenterPoint Energy's cumulative adjusted EPS and certain carbon emissions reduction goals. The market condition is based on CenterPoint Energy's total shareholder return relative to a specified peer group. Upon vesting, shares under the performance awards, as determined based on achievement of the applicable performance goals, are issued to the participants along with the value of dividend equivalents earned over the performance cycle.

The stock unit awards granted in 2024, 2023 and 2022 are service based and subject to CenterPoint Energy's achievement of positive operating income for the last full calendar year preceding the applicable vesting date. Stock units awarded in 2024 are service based, and vest under a three-year ratable vesting schedule, with one-third vesting as of each of the first three anniversaries of the grant date. Each vesting is subject to the achievement of a performance goal. Stock unit awards granted to employees in 2023 and 2022 cliff vest at the end of a three-year period. Stock unit awards granted to non-employee directors vest immediately upon grant. Upon vesting, shares under the stock unit awards are issued to the participants along with the value of dividend equivalents earned over the applicable vesting period.

The following table summarizes CenterPoint Energy's expenses related to LTIPs for the periods presented:

	Year Ended December 31,		
	2024	2023	2022
	(in millions)		
LTIP compensation expense (1)	$ 34	$ 65	$ 51
Income tax benefit recognized	8	15	12
Actual tax benefit realized for tax deductions	19	17	6

(1) Included in Operation and maintenance expense in CenterPoint Energy's Statements of Consolidated Income, net of any amounts capitalized.

The following tables summarize CenterPoint Energy's LTIP activity for the year ended December 31, 2024:

	Shares (Thousands)	Weighted-Average Grant Date Fair Value	Remaining Average Contractual Life (Years)	Aggregate Intrinsic Value (2) (Millions)
Performance Awards (1)				
Outstanding and nonvested as of December 31, 2023	5,225	$ 25.95		
Granted	1,727	27.92		
Forfeited or canceled	(220)	28.09		
Vested and released to participants	(1,824)	21.87		
Outstanding and nonvested as of December 31, 2024	4,908	$ 28.14	1	$ 105
Stock Unit Awards				
Outstanding and nonvested as of December 31, 2023	1,861	$ 26.91		
Granted	438	28.25		
Forfeited or canceled	(43)	27.92		
Vested and released to participants	(1,139)	25.92		
Outstanding and nonvested as of December 31, 2024	1,117	$ 28.20	0.5	$ 36

(1) Reflects maximum performance achievement.
(2) Reflects the impact of current expectations of achievement and stock price.

Additional information related to the Performance Awards and Stock Unit Awards was as follows for the periods presented:

	Year Ended December 31,		
	2024	2023	2022
	(in millions, except for per unit amounts)		
Performance Awards			
Weighted-average grant date fair value per unit of awards granted	$ 27.92	$ 29.18	$ 28.12
Total intrinsic value of awards received by participants	51	47	13
Vested grant date fair value	40	37	13
Stock Unit Awards			
Weighted-average grant date fair value per unit of awards granted	$ 28.25	$ 30.83	$ 28.44
Total intrinsic value of awards received by participants	33	28	14
Vested grant date fair value	30	23	13

As of December 31, 2024, there was $39 million of total unrecognized compensation cost related to nonvested performance and stock unit awards which is expected to be recognized over a weighted-average period of 1.7 years.

(b) Pension Benefits (CenterPoint Energy)

CenterPoint Energy maintains a non-contributory qualified defined benefit pension plan covering certain eligible employees, which is closed to new participants. CenterPoint Energy also maintains three additional qualified defined benefit pension plans, two of which are closed to new participants and one of which is frozen, that cover certain eligible employees and retirees of Vectren and are primarily non-contributory. In addition to the qualified defined benefit pension plans, CenterPoint Energy maintains unfunded non-qualified benefit restoration plans which allow participants to receive the benefits to which they would have been entitled under CenterPoint Energy's qualified pension plan except for federally mandated limits on qualified plan benefits or on the level of compensation on which qualified plan benefits may be calculated. CenterPoint Energy also maintains a frozen non-qualified supplemental retirement plan covering certain former executives of Vectren.

In December 2022, the CenterPoint Energy Retirement Plan, a tax-qualified defined benefit pension plan, completed the 2022 Annuity Purchase to fund the annuities of certain retirees of the non-regulated business units of CenterPoint Energy (including previously divested businesses), as part of a de-risking strategy. The 2022 Annuity Purchase reduced the plan's benefit obligation by $138 million and plan assets by $136 million, which were transferred to the annuity provider. The $138 million transferred benefit obligation represented 9.4% of CenterPoint Energy's total benefit obligation as of its last remeasurement prior to the transaction. As a result of this transaction, CenterPoint Energy incurred a settlement charge of $47 million. In addition, CenterPoint Energy was relieved of all responsibility for these pension obligations and the annuity

provider assumed the obligation to pay and administer the pension benefits for the 1,119 impacted retirees and beneficiaries, with no changes to the amount, timing or form of the benefit payments.

CenterPoint Energy's net periodic cost includes the following components relating to pension, including the non-qualified benefit plans, for the periods presented:

	Year Ended December 31,		
	2024	2023	2022
	(in millions)		
Service cost (1)	$ 25	$ 25	$ 29
Interest cost (2)	73	76	73
Expected return on plan assets (2)	(75)	(76)	(87)
Amortization of net loss (2)	28	28	31
Settlement cost (2) (3)	—	—	126
Net periodic cost	$ 51	$ 53	$ 172

(1) Included in Operation and maintenance expense in CenterPoint Energy's Statements of Consolidated Income, net of amounts capitalized and regulatory deferrals.
(2) Included in Other income (expense), net in CenterPoint Energy's Statements of Consolidated Income, net of regulatory deferrals.
(3) A one-time, non-cash settlement cost is required when the total lump sum distributions or other settlements of plan benefit obligations during a plan year exceed the service cost and interest cost components of the net periodic cost for that year. In 2023 and 2022, CenterPoint Energy recognized non-cash settlement cost due to lump sum settlement payments. The transfer of assets related to the 2022 Annuity Purchase is considered a lump sum settlement payment.

CenterPoint Energy used the following assumptions to determine net periodic cost relating to pension benefits for the periods presented:

	Year Ended December 31,		
	2024	2023	2022
Discount rate	4.95 %	5.15 %	2.80 %
Expected return on plan assets	6.50	6.50	5.00
Rate of increase in compensation levels	4.97	4.99	4.95

In determining net periodic benefit cost, CenterPoint Energy uses fair value, as of the beginning of the year, as its basis for determining expected return on plan assets except for two of Vectren's qualified defined benefit pension plans which use a market related value of assets.

The following table summarizes changes in the benefit obligation, changes in plan assets, the amounts recognized in the Consolidated Balance Sheets as well as the key actuarial assumptions of CenterPoint Energy's pension plans. The measurement dates for plan assets and benefit obligations were December 31, 2024 and 2023.

	December 31, 2024	December 31, 2023
	(in millions, except for actuarial assumptions)	
Change in Benefit Obligation		
Benefit obligation, beginning of year	$ 1,548	$ 1,553
Service cost	25	25
Interest cost	73	76
Benefits paid	(127)	(147)
Actuarial (gain) loss (1)	(42)	41
Benefit obligation, end of year	1,477	1,548
Change in Plan Assets		
Fair value of plan assets, beginning of year	1,204	1,212
Employer contributions	30	32
Benefits paid	(127)	(147)
Actual investment return	25	107
Fair value of plan assets, end of year	1,132	1,204
Funded status, end of year	$ (345)	$ (344)
Amounts Recognized in Balance Sheets		
Non-current assets	$ 7	$ 4
Current liabilities-other	(7)	(7)
Other liabilities-benefit obligations	(345)	(341)
Net liability, end of year	$ (345)	$ (344)
Actuarial Assumptions		
Discount rate (2)	5.60 %	4.95 %
Expected return on plan assets (3)	7.00	6.50
Rate of increase in compensation levels	4.79	4.97
Interest crediting rate	3.00	3.00

(1) Significant sources of actuarial gain for 2024 include the increase in discount rate from 4.95% to 5.60%, offset by losses due to expected return on plan assets exceeding actual return on plan assets.
(2) The discount rate assumption was determined by matching the projected cash flows of CenterPoint Energy's plans against a hypothetical yield curve of high-quality corporate bonds represented by a series of annualized individual discount rates from one-half to 99 years.
(3) The expected rate of return assumption was developed using the targeted asset allocation of CenterPoint Energy's plans and the expected return for each asset class.

The following table displays pension benefits related to CenterPoint Energy's pension plans that have accumulated benefit obligations in excess of plan assets as of the dates presented:

	December 31, 2024		December 31, 2023	
	Pension (Qualified)	Pension (Non-qualified)	Pension (Qualified)	Pension (Non-qualified)
	(in millions)			
Accumulated benefit obligation	$ 1,431	$ 44	$ 1,496	$ 48
Projected benefit obligation	1,433	44	1,500	48
Fair value of plan assets	1,132	—	1,204	—

The accumulated benefit obligation for all defined benefit pension plans on CenterPoint Energy's Consolidated Balance Sheets was $1,475 million and $1,544 million as of December 31, 2024 and 2023, respectively.

(c) Postretirement Benefits

CenterPoint Energy provides certain healthcare and life insurance benefits for eligible retired employees on both a contributory and non-contributory basis. The Registrants' employees (other than employees of Vectren and its subsidiaries) who were hired before January 1, 2018 and who have met certain age and service requirements at retirement, as defined in the plan, are eligible to participate in these benefits, provided, however, that life insurance benefits are available only for eligible retired employees who retired before January 1, 2022. Employees hired on or after January 1, 2018 are not eligible for these benefits, except that such employees represented by IBEW Local Union 66 are eligible to participate in certain of the benefits, subject to the applicable age and service requirements. With respect to retiree medical and prescription drug benefits, and, effective January 1, 2021, dental and vision benefits, employees represented by the IBEW Local Union 66 who retire on or after January 1, 2017, and their dependents, receive any such benefits exclusively through the NECA/IBEW Family Medical Care Plan pursuant to the terms of the applicable collective bargaining agreement. Houston Electric and CERC are required to fund a portion of their obligations in accordance with rate orders. All other obligations are funded on a pay-as-you-go basis.

CenterPoint Energy, through Vectren, also maintains a postretirement benefit plan that provides health care and life insurance benefits, which are a combination of self-insured and fully insured programs, to eligible Vectren retirees on both a contributory and non-contributory basis.

Postretirement benefits are accrued over the active service period of employees. The net postretirement benefit cost includes the following components for the periods presented:

	Year Ended December 31,								
	2024			2023			2022		
	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC
	(in millions)								
Service cost (1)	$ 1	$ —	$ 1	$ 1	$ —	$ 1	$ 2	$ —	$ 1
Interest cost (2)	13	5	4	13	5	5	9	4	3
Expected return on plan assets (2)	(6)	(4)	(1)	(5)	(4)	(1)	(5)	(4)	(1)
Amortization of prior service cost (credit) (2)	(2)	(5)	2	(2)	(5)	2	(3)	(4)	2
Amortization of net loss (2)	(8)	(4)	(3)	(8)	(4)	(3)	(4)	(2)	(1)
Net postretirement benefit cost (credit)	$ (2)	$ (8)	$ 3	$ (1)	$ (8)	$ 4	$ (1)	$ (6)	$ 4

(1) Included in Operation and maintenance expense in each of the Registrants' respective Statements of Consolidated Income, net of amounts capitalized and regulatory deferrals.
(2) Included in Other income (expense), net in each of the Registrants' respective Statements of Consolidated Income, net of regulatory deferrals.

The following assumptions were used to determine net periodic cost relating to postretirement benefits for the periods presented:

	Year Ended December 31,								
	2024			2023			2022		
	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC
Discount rate	4.95 %	4.95 %	4.95 %	5.15 %	5.15 %	5.15 %	2.85 %	2.85 %	2.85 %
Expected return on plan assets	5.21	5.36	4.77	5.13	5.26	4.69	3.22	3.32	2.86

The following table summarizes changes in the benefit obligation, changes in plan assets, the amounts recognized in the Consolidated Balance Sheets and the key actuarial assumptions of the postretirement plans. The measurement dates for plan assets and benefit obligations were December 31, 2024 and 2023.

	December 31, 2024			December 31, 2023		
	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC
	(in millions, except for actuarial assumptions)					
Change in Benefit Obligation						
Benefit obligation, beginning of year	$ 263	$ 113	$ 93	$ 263	$ 115	$ 92
Service cost	1	—	1	1	—	1
Interest cost	13	5	4	13	5	5
Participant contributions	5	2	2	6	2	3
Benefits paid	(21)	(8)	(9)	(20)	(8)	(8)
Actuarial (gain) loss (1)	(22)	(9)	(8)	—	(1)	—
Other transfers	3	1	2	—	—	—
Benefit obligation, end of year	242	104	85	263	113	93
Change in Plan Assets						
Fair value of plan assets, beginning of year	112	86	26	109	84	25
Employer contributions	9	1	5	7	—	4
Participant contributions	5	2	2	6	2	3
Benefits paid	(21)	(8)	(9)	(20)	(8)	(8)
Actual investment return	6	4	2	10	8	2
Other transfers	(8)	(8)	—	—	—	—
Fair value of plan assets, end of year	103	77	26	112	86	26
Funded status, end of year	$ (139)	$ (27)	$ (59)	$ (151)	$ (27)	$ (67)
Amounts Recognized in Balance Sheets						
Current liabilities — other	$ (8)	$ —	$ (4)	$ (7)	$ —	$ (4)
Other liabilities — benefit obligations	(131)	(27)	(55)	(144)	(27)	(63)
Net liability, end of year	$ (139)	$ (27)	$ (59)	$ (151)	$ (27)	$ (67)
Actuarial Assumptions						
Discount rate (2)	5.60 %	5.60 %	5.60 %	4.95 %	4.95 %	4.95 %
Expected return on plan assets (3)	5.21	5.36	4.77	5.13	5.26	4.69
Medical cost trend rate assumed for the next year - Pre-65	6.75	6.75	6.75	7.25	7.25	7.25
Medical/prescription drug cost trend rate assumed for the next year - Post-65	13.74	13.74	13.74	22.76	22.76	22.76
Prescription drug cost trend rate assumed for the next year - Pre-65	10.00	10.00	10.00	9.00	9.00	9.00
Rate to which the cost trend rate is assumed to decline (the ultimate trend rate)	4.50	4.50	4.50	4.50	4.50	4.50
Year that the cost trend rates reach the ultimate trend rate - Pre-65	2034	2034	2034	2033	2033	2033
Year that the cost trend rates reach the ultimate trend rate - Post-65	2034	2034	2034	2033	2033	2033

(1) Significant sources of actuarial gain for 2024 include increase in discount rate from 4.95% to 5.60%, offset by losses from updated claims and demographic review.

(2) The discount rate assumption was determined by matching the projected cash flows of the plans against a hypothetical yield curve of high-quality corporate bonds represented by a series of annualized individual discount rates from one-half to 99 years.

(3) The expected rate of return assumption was developed using the targeted asset allocation of the plans and the expected return for each asset class.

(d) Accumulated Other Comprehensive Income (Loss) (CenterPoint Energy and CERC)

CenterPoint Energy recognizes the funded status of its pension and other postretirement plans on its Consolidated Balance Sheets. To the extent this obligation exceeds amounts previously recognized in the Statements of Consolidated Income, CenterPoint Energy records a regulatory asset for that portion related to its rate-regulated utilities. To the extent that excess liability does not relate to a rate-regulated utility, the offset is recorded as a reduction to equity in accumulated other comprehensive income.

Amounts recognized in accumulated other comprehensive loss (income) consist of the following as of the dates presented:

	December 31, 2024			December 31, 2023		
	Pension Benefits	Postretirement Benefits		Pension Benefits	Postretirement Benefits	
	CenterPoint Energy	CenterPoint Energy	CERC	CenterPoint Energy	CenterPoint Energy	CERC
	(in millions)					
Unrecognized actuarial loss (gain)	$ 52	$ (34)	$ (26)	$ 69	$ (34)	$ (27)
Unrecognized prior service cost	—	9	8	—	12	10
Net amount recognized in accumulated other comprehensive loss (income)	$ 52	$ (25)	$ (18)	$ 69	$ (22)	$ (17)

The changes in plan assets and benefit obligations recognized in other comprehensive income for the year ended December 31, 2024 are as follows:

	Pension Benefits	Postretirement Benefits	
	CenterPoint Energy	CenterPoint Energy	CERC
		(in millions)	
Net actuarial loss (gain)	$ (13)	$ (4)	$ —
Amortization of net actuarial loss (gain)	(4)	2	(2)
Amortization of prior service cost	—	(1)	1
Settlement	—	—	—
Total recognized in comprehensive income	$ (17)	$ (3)	$ (1)
Total recognized in net periodic costs and other comprehensive income	$ 34	$ 1	$ 2

(e) Pension Plan Assets (CenterPoint Energy)

In managing the investments associated with the benefit plans, CenterPoint Energy's objective is to achieve and maintain a fully funded plan. This objective is expected to be achieved through an investment strategy that manages liquidity requirements while maintaining a long-term horizon in making investment decisions and efficient and effective management of plan assets.

As part of the investment strategy discussed above, CenterPoint Energy maintained the following weighted-average allocation targets for its pension plans as of December 31, 2024:

	Minimum	Maximum
U.S. equity	17 %	27 %
International equity	9 %	19 %
Real estate	2 %	8 %
Fixed income	54 %	64 %
Cash	0 %	2 %

The following tables set forth by level, within the fair value hierarchy (see Note 9), CenterPoint Energy's pension plan assets at fair value as of the dates presented:

	December 31, 2024				December 31, 2023			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
	(in millions)							
Cash	$ 36	$ —	$ —	$ 36	$ 21	$ —	$ —	$ 21
Equity securities:								
U.S. companies	28	—	—	28	30	—	—	30
Cash received as collateral from securities lending	88	—	—	88	94	—	—	94
Obligation to return cash received as collateral from securities lending	(88)	—	—	(88)	(94)	—	—	(94)
U.S. treasuries and government agencies	156	—	—	156	178	—	—	178
Corporate bonds:								
Investment grade or above	—	428	—	428	—	469	—	469
Mortgage-backed securities	—	12	—	12	—	15	—	15
Asset-backed securities	—	1	—	1	—	1	—	1
Municipal bonds	—	19	—	19	—	25	—	25
International government bonds	—	13	—	13	—	9	—	9
Financial instruments	—	(3)	—	(3)	—	(4)	—	(4)
Total investments at fair value	$ 220	$ 470	$ —	690	$ 229	$ 515	$ —	744
Investments measured by net asset value per share or its equivalent (1) (2)				442				460
Fair value of plan assets				$ 1,132				$ 1,204

(1) Represents investments in pooled investment funds and common collective trust funds.

(2) The amounts invested in pooled investment funds were 100% allocated to real estate. The amounts invested common collective trust funds were allocated as follows as of the dates presented:

	December 31, 2024	December 31, 2023
International equities	38 %	40 %
U.S. equities	61 %	59 %
Fixed income	1 %	1 %

Level 2 investments, which do not have a quoted price in active market, are valued using the market data provided by independent pricing services or major market makers, to arrive at a price a dealer would pay for the security.

The pension plans utilized both exchange traded and over-the-counter financial instruments such as futures, interest rate options and swaps that were marked to market daily with the gains or losses settled in the cash accounts. The pension plans did not include any holdings of CenterPoint Energy Common Stock as of December 31, 2024 or 2023.

(f) Postretirement Plan Assets

In managing the investments associated with the postretirement plans, the Registrants' primary objective is to preserve and improve the funded status of the plan, while minimizing volatility. This objective is expected to be achieved through an investment strategy that manages liquidity requirements while maintaining a long-term horizon in making investment decisions and efficient and effective management of plan assets.

As part of the investment strategy discussed above, the Registrants maintained the following weighted-average allocation targets for the postretirement plans as of December 31, 2024:

	CenterPoint Energy		Houston Electric		CERC	
	Minimum	Maximum	Minimum	Maximum	Minimum	Maximum
U.S. equities	14 %	24 %	13 %	23 %	15 %	25 %
International equities	3 %	13 %	3 %	13 %	2 %	12 %
Fixed income	69 %	79 %	69 %	79 %	68 %	78 %
Cash	0 %	2 %	0 %	2 %	0 %	2 %

The following table sets forth by level, within the fair value hierarchy (see Note 9), the Registrants' postretirement plan assets, all of which were mutual funds, at fair value as of the dates presented:

	December 31, 2024				December 31, 2023			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
	(in millions)							
CenterPoint Energy	$ 103	$ —	$ —	$ 103	$ 113	$ —	$ —	$ 113
Houston Electric	77	—	—	77	86	—	—	86
CERC	26	—	—	26	26	—	—	26

The amounts invested in mutual funds were allocated as follows as of the dates presented:

	December 31, 2024			December 31, 2023		
	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC
U.S. equities	19 %	18 %	21 %	20 %	19 %	22 %
International equities	7 %	8 %	7 %	8 %	9 %	6 %
Fixed income	74 %	74 %	72 %	72 %	72 %	71 %

(g) Benefit Plan Contributions

The Registrants made the following contributions in 2024 and are required to make the following minimum contributions in 2025 to the indicated benefit plans below:

	Contributions in 2024			Expected Minimum Contributions in 2025		
	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC
	(in millions)					
Qualified pension plans	$ 23	$ —	$ —	$ 105	$ —	$ —
Non-qualified pension plans	7	—	—	7	—	—
Postretirement benefit plans	9	1	5	8	1	5

Benefit payments are expected to be paid by the pension and postretirement benefit plans as follows:

	Pension Benefits	Postretirement Benefits		
	CenterPoint Energy	CenterPoint Energy	Houston Electric	CERC
		(in millions)		
2025	$ 144	$ 16	$ 7	$ 6
2026	144	18	8	6
2027	141	19	8	7
2028	138	20	9	7
2029	134	21	9	7
2030-2034	609	102	46	35

(h) Savings Plan

CenterPoint Energy maintains the CenterPoint Energy Savings Plan, a tax-qualified employee savings plan that includes a cash or deferred arrangement under Section 401(k) of the Code and an employee stock ownership plan under Section 4975(e)(7) of the Code. Under the plan, participating employees may make pre-tax or Roth contributions and, if eligible, after-tax contributions up to certain federally mandated limits. Participating Registrants provide matching contributions and, as of January 1, 2020, for certain eligible employees, non-elective contributions up to certain limits.

The CenterPoint Energy Savings Plan has significant holdings of Common Stock. As of December 31, 2024, 7,136,941 shares of Common Stock were held by the savings plan, which represented approximately 6% of its investments. Given the concentration of the investments in Common Stock, the savings plan and its participants have market risk related to this investment. The savings plan limits the percentage of future contributions that can be invested in Common Stock to 25% and prohibits transfers of account balances where the transfer would result in more than 25% of a participant's total account balance invested in Common Stock.

CenterPoint Energy allocates the savings plan benefit expense to Houston Electric and CERC related to their respective employees. The following table summarizes the Registrants' savings plan benefit expense for the periods presented:

	Year Ended December 31,								
	2024			2023			2022		
	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC
	(in millions)								
Savings plan benefit expenses (1)	$ 72	$ 27	$ 23	$ 67	$ 23	$ 20	$ 72	$ 23	$ 22

(1) Amounts presented in the table above are included in Operation and maintenance expense in the Registrants' respective Statements of Consolidated Income and shown prior to any amounts capitalized.

(i) Other Benefits Plans

CenterPoint Energy maintains non-qualified deferred compensation plans that provide benefits payable to eligible directors, officers and select employees or their designated beneficiaries at specified future dates or upon termination, retirement or death. Benefit payments are made from the general assets of the participating Registrants or, in the case of certain plans, from a rabbi trust that is a grantor trust and remains subject to the claims of general creditors under applicable state and federal law.

Expenses related to other benefit plans were recorded as follows for the periods presented:

	Year Ended December 31,								
	2024			2023			2022		
	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC
	(in millions)								
Deferred compensation plans	$ 3	$ —	$ —	$ (1)	$ —	$ —	$ 1	$ —	$ —

Amounts related to other benefit plans were included in Benefit Obligations in the Registrants' accompanying Consolidated Balance Sheets as follows:

	December 31, 2024			December 31, 2023		
	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC
	(in millions)					
Deferred compensation plans	$ 22	$ 3	$ 1	$ 26	$ 3	$ 1
Split-dollar life insurance arrangements	46	1	—	46	1	—

(j) Change in Control Agreements and Other Employee Matters

CenterPoint Energy has a change in control plan, which was amended and restated on May 1, 2017. The plan generally provides, to the extent applicable, in the case of the occurrence of both a change in control of CenterPoint Energy and a covered

termination of employment, for severance benefits of up to three times annual base salary plus bonus and other benefits. Certain CenterPoint Energy officers are participants under the plan.

As of December 31, 2024, the Registrants' employees were covered by collective bargaining agreements as follows:

		Percentage of Employees Covered		
	Agreement Expiration	CenterPoint Energy	Houston Electric	CERC
IBEW Local 66	May 2026	17 %	53 %	— %
OPEIU Local 12	December 2025	2 %	— %	2 %
Gas Workers Union Local 340	April 2025	5 %	— %	12 %
IBEW Locals 1393 and USW Locals 12213 & 7441	December 2026	3 %	— %	8 %
IBEW Locals 949	December 2025	3 %	— %	7 %
USW Locals 13-227	June 2027	5 %	— %	13 %
USW Locals 13-1	June 2027	— %	— %	1 %
IBEW Local 702	June 2025	3 %	— %	— %
Teamsters Local 135/215	September 2027	— %	— %	— %
UWUA Local 175	October 2027	1 %	— %	4 %
Total		39 %	53 %	47 %

The collective bargaining agreements with Gas Workers Union Local 340, IBEW Local 949 and OPEIU Local 12 related to CERC employees in Minnesota, as well as with IBEW Local 702 related to SIGECO employees, are scheduled to expire in April 2025, December 2025, December 2025 and June 2025, respectively, and negotiations of these agreements are expected to be completed before the respective expirations.

(9) Fair Value Measurements

Assets and liabilities that are recorded at fair value in the Registrants' Consolidated Balance Sheets are categorized based upon the level of judgment associated with the inputs used to measure their value. Hierarchical levels, as defined below and directly related to the amount of subjectivity associated with the inputs to fair valuations of these assets and liabilities, are as follows:

Level 1: Inputs are unadjusted quoted prices in active markets for identical assets or liabilities at the measurement date. The types of assets carried at Level 1 fair value generally are exchange-traded derivatives and equity securities.

Level 2: Inputs, other than quoted prices included in Level 1, are observable for the asset or liability, either directly or indirectly. Level 2 inputs include quoted prices for similar instruments in active markets and inputs other than quoted prices that are observable for the asset or liability. Fair value assets and liabilities that are generally included in this category are derivatives with fair values based on inputs from actively quoted markets. A market approach is utilized to value the Registrants' Level 2 natural gas derivative assets or liabilities. CenterPoint Energy's Level 2 indexed debt securities derivative is valued using an option model and a discounted cash flow model, which uses projected dividends on the ZENS-Related Securities and a discount rate as observable inputs.

Level 3: Inputs are unobservable for the asset or liability, and include situations where there is little, if any, market activity for the asset or liability. Unobservable inputs reflect the Registrants' judgments about the assumptions market participants would use in pricing the asset or liability since limited market data exists. The Registrants develop these inputs based on the best information available, including the Registrants' own data.

The Registrants determine the appropriate level for each financial asset and liability on a quarterly basis and recognize transfers between levels at the end of the reporting period. As of December 31, 2024 and December 31, 2023, the Registrants did not have any assets or liabilities classified as Level 3.

The following tables present information about the Registrants' assets and liabilities measured at fair value on a recurring basis as of December 31, 2024 and December 31, 2023 and indicate the fair value hierarchy of the valuation techniques utilized by the Registrants to determine such fair value:

CenterPoint Energy

	December 31, 2024				December 31, 2023			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets				(in millions)				
Equity securities	$ 561	$ —	$ —	$ 561	$ 541	$ —	$ —	$ 541
Investments, including money market funds (1)	22	—	—	22	31	—	—	31
Natural gas derivatives (1)	—	1	—	1	—	—	—	—
Total assets	$ 583	$ 1	$ —	$ 584	$ 572	$ —	$ —	$ 572
Liabilities								
Indexed debt securities derivative	$ —	$ 619	$ —	$ 619	$ —	$ 605	$ —	$ 605
Natural gas derivatives (2)	—	3	—	3	—	12	—	12
Total liabilities	$ —	$ 622	$ —	$ 622	$ —	$ 617	$ —	$ 617

Houston Electric

	December 31, 2024				December 31, 2023			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets				(in millions)				
Investments, including money market funds (1)	$ 5	$ —	$ —	$ 5	$ 14	$ —	$ —	$ 14
Total assets	$ 5	$ —	$ —	$ 5	$ 14	$ —	$ —	$ 14

CERC

	December 31, 2024				December 31, 2023			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets				(in millions)				
Investments, including money market funds (1)	$ 15	$ —	$ —	$ 15	$ 15	$ —	$ —	$ 15
Natural gas derivatives (1)	—	1	—	1	—	—	—	—
Total assets	$ 15	$ 1	$ —	$ 16	$ 15	$ —	$ —	$ 15
Liabilities								
Natural gas derivatives (2)	$ —	$ 2	$ —	$ 2	$ —	$ 11	$ —	$ 11
Total liabilities	$ —	$ 2	$ —	$ 2	$ —	$ 11	$ —	$ 11

(1) Included in Prepaid expenses and other current assets in the respective Consolidated Balance Sheets.
(2) Included in Other current liabilities in the respective Consolidated Balance Sheets.

Items Measured at Fair Value on a Nonrecurring Basis

As a result of classifying the Louisiana and Mississippi natural gas LDC businesses as held for sale, CenterPoint Energy and CERC used a market approach consisting of contractual sales price adjusted for estimated working capital and other contractual purchase price adjustments to determine the fair value of the businesses classified as held for sale, which are Level 2 inputs. Neither CenterPoint Energy nor CERC recognized any gains or losses upon classification as held for sale for the year ended December 31, 2024. See Note 4 for further information.

Estimated Fair Value of Financial Instruments

The fair values of cash and cash equivalents, investments in equity securities measured at fair value and short-term borrowings under AMAs are estimated to be approximately equivalent to carrying amounts and have been excluded from the table below. The carrying amounts of non-trading derivative assets and liabilities and CenterPoint Energy's ZENS indexed debt securities derivative are stated at fair value and are excluded from the table below. The fair value of each debt instrument is determined by multiplying the principal amount of each debt instrument by a combination of historical trading prices and

comparable issue data. These liabilities, which are not measured at fair value in the Registrants' Consolidated Balance Sheets, but for which the fair value is disclosed, would be classified as Level 2 in the fair value hierarchy.

	December 31, 2024			December 31, 2023		
	CenterPoint Energy (1)	Houston Electric (1)	CERC	CenterPoint Energy (1)	Houston Electric (1)	CERC
Long-term debt, including current maturities			(in millions)			
Carrying amount	$ 20,961	$ 8,822	$ 5,184	$ 18,609	$ 7,587	$ 4,670
Fair value	19,597	7,746	5,032	17,804	6,917	4,627

(1) Includes Securitization Bonds, as applicable.

(10) Equity Securities and Indexed Debt Securities (ZENS) (CenterPoint Energy)

(a) Equity Securities

Gains and losses on equity securities, net of transaction costs, are recorded as Gain (loss) on equity securities in CenterPoint Energy's Statements of Consolidated Income. The following table presents unrealized gains (losses), net on equity securities owned by CenterPoint Energy for each period presented:

	Year Ended December 31,		
	2024	2023	2022
		(in millions)	
AT&T Common	$ 62	$ (17)	$ (63)
Charter Common	(40)	43	(273)
WBD Common	(2)	5	23
Energy Transfer Common Units (1)	—	—	95
Energy Transfer Series G Preferred Units (1)	—	—	(9)
Total unrealized gains (losses) on equity securities, net	$ 20	$ 31	$ (227)

(1) In 2022, CenterPoint Energy completed the execution of its previously announced plan to exit the midstream sector by selling its remaining Energy Transfer Common Units and Energy Transfer Series G Preferred Units.

CenterPoint Energy and its subsidiaries hold shares of certain securities, which are classified as trading securities. Shares of AT&T Common, Charter Common and WBD Common are expected to be held to facilitate CenterPoint Energy's ability to meet its obligation under the ZENS. The following table presented the shares held by CenterPoint Energy and their carrying value for each period presented:

	Shares Held at December 31,		Carrying Value at December 31,	
	2024	2023	2024	2023
			(in millions)	
AT&T Common	10,212,945	10,212,945	$ 233	$ 171
Charter Common	872,503	872,503	299	339
WBD Common	2,470,685	2,470,685	26	28
Other			3	3
Total			$ 561	$ 541

(b) ZENS

In September 1999, CenterPoint Energy issued ZENS having an original principal amount of $1.0 billion, of which $828 million remained outstanding as of December 31, 2024. Each ZENS is exchangeable at the holder's option at any time for an amount of cash equal to 95% of the market value of the reference shares attributable to such note. The number and identity of the reference shares attributable to each ZENS are adjusted for certain corporate events. CenterPoint Energy's reference shares for each ZENS consisted of the following as of the dates presented:

	December 31, 2024	December 31, 2023
	(in shares)	
AT&T Common	0.7185	0.7185
Charter Common	0.061382	0.061382
WBD Common	0.173817	0.173817

CenterPoint Energy pays interest on the ZENS at an annual rate of 2% plus the amount of any quarterly cash dividends paid in respect of the reference shares attributable to the ZENS. The principal amount of the ZENS is subject to increases or decreases to the extent that the annual yield from interest and cash dividends on the reference shares attributable to the ZENS is less than or more than 2.309%. The adjusted principal amount is defined in the ZENS instrument as "contingent principal." As of December 31, 2024, the ZENS, having an original principal amount of $828 million and a contingent principal amount of $9 million, were outstanding and were exchangeable, at the option of the holders, for cash equal to 95% of the market value of the reference shares attributable to the ZENS. As of December 31, 2024, the market value of such shares was approximately $558 million, which would provide an exchange amount of $640 for each $1,000 original principal amount of ZENS. At maturity of the ZENS in 2029, CenterPoint Energy will be obligated to pay in cash the higher of the contingent principal amount of the ZENS or an amount based on the then-current market value of the reference shares, which will include any additional publicly-traded securities distributed with respect to the current reference shares prior to maturity.

The ZENS obligation is bifurcated into a debt component and a derivative component (the holder's option to receive the appreciated value of the reference shares at maturity). The bifurcated debt component accretes through interest charges annually up to the contingent principal amount of the ZENS in 2029. Such accretion will be reduced by annual cash interest payments, as previously described. The derivative component is recorded at fair value and changes in the fair value of the derivative component are recorded as Gain (loss) on indexed debt securities in CenterPoint Energy's Statements of Consolidated Income. Changes in the fair value of the ZENS-Related Securities held by CenterPoint Energy are expected to substantially offset changes in the fair value of the derivative component of the ZENS.

The following table provides summarized financial information related to CenterPoint Energy's investment in ZENS-Related Securities and each component of CenterPoint Energy's ZENS obligation for the periods presented:

	ZENS-Related Securities	Debt Component of ZENS	Derivative Component of ZENS
		(in millions)	
Balance as of December 31, 2021	$ 820	$ 10	$ 903
Accretion of debt component of ZENS	—	17	—
2% interest paid	—	(17)	—
Distribution to ZENS holders	—	(3)	—
Gain on indexed debt securities	—	—	(325)
Loss on ZENS-Related Securities	(313)	—	—
Balance as of December 31, 2022	507	7	578
Accretion of debt component of ZENS	—	17	—
2% interest paid	—	(17)	—
Distribution to ZENS holders	—	(2)	—
Loss on indexed debt securities	—	—	27
Gain on ZENS-Related Securities	31	—	—
Balance as of December 31, 2023	538	5	605
Accretion of debt component of ZENS	—	16	—
2% interest paid	—	(17)	—
Distribution to ZENS holders	—	(2)	—
Loss on indexed debt securities	—	—	14
Gain on ZENS-Related Securities	20	—	—
Balance as of December 31, 2024	$ 558	$ 2	$ 619

(11) Equity (CenterPoint Energy)

Dividends Declared and Paid (CenterPoint Energy)

CenterPoint Energy's dividends declared and dividends paid during 2024, 2023 and 2022 are presented below:

	Dividends Declared Per Share			Dividends Paid Per Share		
	2024	2023	2022	2024	2023	2022
Common Stock	$ 0.830	$ 0.780	$ 0.720	$ 0.810	$ 0.770	$ 0.700
Series A Preferred Stock (1)	$ —	$ 30.625	$ 61.250	$ —	$ 61.250	$ 61.250

(1) All of the outstanding shares of Series A Preferred Stock were redeemed during 2023 as further described below.

Common Stock (CenterPoint Energy)

(a) Underwritten Offering

On August 9, 2024, CenterPoint Energy issued 9,754,194 shares of Common Stock in an underwritten public offering at a price of $25.36 per share, for net proceeds of $247 million after deducting issuance costs. The proceeds from the offering were used for the repayment of a portion of CenterPoint Energy's then-outstanding commercial paper.

(b) Equity Distribution Agreement

On January 10, 2024, CenterPoint Energy entered into an Equity Distribution Agreement with certain financial institutions with respect to the offering and sale from time to time of shares of Common Stock, having an aggregate gross sales price of up to $500 million. Sales of Common Stock may be made by any method permitted by applicable law and deemed to be an "at the market offering" as defined in Rule 415 of the Securities Act of 1933, as amended. CenterPoint Energy may also enter into one or more forward sales agreements pursuant to master forward confirmations. The offer and sale of Common Stock under the Equity Distribution Agreement will terminate upon the earliest of (1) the sale of all Common Stock subject to the Equity Distribution Agreement, (2) termination of the Equity Distribution Agreement or (3) May 17, 2026. During the year ended

December 31, 2024, CenterPoint Energy issued 8,790,848 shares of Common Stock through the ATM Managers under the Equity Distribution Agreement, representing aggregate cash proceeds of $247 million, which was net of compensation paid by CenterPoint Energy to the ATM Managers of $2 million. As of December 31, 2024, CenterPoint Energy had not entered into any forward sale agreements under the at-the-market program. Additionally, as of December 31, 2024, CenterPoint Energy had $250 million of remaining capacity available under the program.

Series A Preferred Stock (CenterPoint Energy)

	Liquidation Preference Per Share	Share Outstanding as of December 31,			Outstanding Value as of December 31,		
		2024	2023	2022	2024	2023	2022
		(in millions, except shares and per share amount)					
Series A Preferred Stock (1)	$ 1,000	—	—	800,000	$ —	$ —	$ 790

(1) All of the outstanding shares of Series A Preferred Stock were redeemed during 2023 as further described below.

Income Allocated to Series A Preferred Shareholders

	Year Ended December 31,		
	2024	2023	2022
		(in millions)	
Series A Preferred Stock	$ —	$ 50	$ 49

Prior to the redemption of all outstanding shares of Series A Preferred Stock in September 2023, as further described below, the aggregate liquidation value of the Series A Preferred Stock was $800 million with a per share liquidation value of $1,000. The Series A Preferred Stock was redeemable at CenterPoint Energy's election on or after September 1, 2023, for cash at a redemption price of $1,000 per share, plus any accumulated and unpaid dividends thereon to, but excluding, the redemption date.

Dividends. The Series A Preferred Stock accrued cumulative dividends, calculated as a percentage of the stated amount per share, at a fixed annual rate of 6.125% per annum to be paid in cash if, when and as declared. If declared, dividends were payable semi-annually in arrears on each March 1 and September 1, beginning on March 1, 2019. Cumulative dividends earned during the applicable periods are presented on CenterPoint Energy's Statements of Consolidated Income as Preferred stock dividend requirement.

Redemption of Series A Preferred Stock. On September 1, 2023, CenterPoint Energy redeemed all 800,000 outstanding shares of Series A Preferred Stock, in whole for cash at a redemption price of $1,000.

Accumulated Other Comprehensive Income (Loss) (CenterPoint Energy, Houston Electric and CERC)

Changes in accumulated other comprehensive income (loss) are as follows for the periods presented:

	Year Ended December 31,					
	2024			2023		
	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC
	(in millions)					
Beginning Balance	$ (35)	$ —	$ 16	$ (31)	$ —	$ 16
Other comprehensive income (loss) before reclassifications:						
Remeasurement of pension and other postretirement plans	16	(1)	2	(8)	—	—
Net deferred gain from cash flow hedges	4	—	—	1	—	—
Amounts reclassified from accumulated other comprehensive income (loss):						
Prior service cost (benefit) (1)	1	—	1	1	—	(2)
Actuarial losses (gain) (1)	2	—	(2)	1	—	2
Reclassification of deferred gain from cash flow hedges realized in net income	(1)	—	—	—	—	—
Tax benefit (expense)	(4)	—	—	1	—	—
Other comprehensive income (loss)	18	(1)	1	(4)	—	—
Ending Balance	$ (17)	$ (1)	$ 17	$ (35)	$ —	$ 16

(1) Amounts are included in the computation of net periodic cost and are reflected in Other income (expense), net in each of the Registrants' respective Statements of Consolidated Income.

(12) Short-term Borrowings and Long-term Debt

Short-term Borrowings and Long-term Debt: As of December 31, 2024 and 2023, the Registrants had the following short-term borrowings and long-term debt outstanding:

	December 31, 2024		December 31, 2023	
	Long-Term	Current (1)	Long-Term	Current (1)
	(in millions)			
CenterPoint Energy:				
ZENS due 2029 (2)	$ —	$ 2	$ —	$ 5
CenterPoint Energy senior notes 1.45% to 5.25% due 2026 to 2049	3,950	—	3,250	850
CenterPoint Energy junior subordinated notes 6.70% to 7.00% due 2055	1,300	—	—	—
CenterPoint Energy pollution control bonds 5.125% due 2028 (3)	68	—	68	—
CenterPoint Energy commercial paper (4)	382	—	1,036	—
SIGECO first mortgage bonds 3.450% to 6.00% due 2025 to 2055 (5)	944	41	825	22
SIGECO securitization bonds 5.026% to 5.172% due 2036 to 2041 (6)	311	13	324	17
Unamortized debt issuance costs	(48)	—	(35)	—
Unamortized discount and premium, net	(6)	—	(5)	—
Houston Electric debt (see details below)	8,322	500	7,426	161
CERC debt (see details below)	5,174	10	4,670	4
Total CenterPoint Energy debt	$ 20,397	$ 566	$ 17,559	$ 1,059
Houston Electric:				
Short Term Borrowings:				
Term loan	$ —	$ 500	$ —	$ —
Long-term debt:				
General mortgage bonds 2.35% to 6.95% due 2026 to 2053 (7)	$ 8,412	$ —	$ 7,512	$ —
Other	1	—	1	—
Bond Company IV:				
Transition bonds 3.028% due 2024	—	—	—	161
Unamortized debt issuance costs	(62)	—	(59)	—
Unamortized discount and premium, net	(29)	—	(28)	—
Total Houston Electric debt	$ 8,322	$ 500	$ 7,426	$ 161
CERC (8):				
Short-term borrowings:				
Inventory financing (9)	$ —	$ —	$ —	$ 4
Long-term debt:				
Senior notes 1.75% to 6.625% due 2026 to 2047	$ 4,520	$ —	$ 4,120	$ —
Indiana Gas senior notes 6.34% to 7.08% due 2025 to 2029	86	10	96	—
Commercial paper (4)	599	—	484	—
Unamortized debt issuance costs	(31)	—	(31)	—
Unamortized discount and premium, net	—	—	1	—
Total CERC debt	$ 5,174	$ 10	$ 4,670	$ 4

(1) Includes amounts due or exchangeable within one year of the date noted.

(2) CenterPoint Energy's ZENS obligation is bifurcated into a debt component and an embedded derivative component. For additional information regarding ZENS, see Note 10(b). As ZENS are exchangeable for cash at any time at the option of the holders, these notes are classified as a current portion of long-term debt.

(3) These pollution control bonds were secured by general mortgage bonds of Houston Electric as of December 31, 2024 and 2023 and are not reflected in Houston Electric's consolidated financial statements because of the contingent nature of the obligations.

(4) Commercial paper issued by CenterPoint Energy and CERC Corp. has maturities up to 60 days and 30 days, respectively, and are backstopped by the respective issuer's long-term revolving credit facility. Commercial paper is classified as long-term because the termination date of the facility that backstops the commercial paper is more than one year from the balance sheet date.

(5) The first mortgage bonds issued by SIGECO subject SIGECO's properties to a lien under the related mortgage indenture as further discussed below.
(6) Scheduled final payment dates are November 15, 2036 and May 15, 2041. The SIGECO Securitization Bonds will be repaid over time through a securitization charge imposed on retail electric customers in SIGECO's service territory.
(7) The general mortgage bonds issued by Houston Electric subject Houston Electric's properties to a lien under the General Mortgage as further discussed below.
(8) Issued by CERC Corp.
(9) Represents AMA transactions accounted for as an inventory financing.

Debt Transactions

Debt Issuances. During 2024, the following debt instruments were issued or incurred:

Registrant	Issuance Date	Debt Instrument	Aggregate Principal Amount	Interest Rate	Maturity Date
			(in millions, except for interest rates)		
Houston Electric (1)	February 2024	General Mortgage Bonds	$ 400	5.15%	2034
Houston Electric (2)	June 2024	Term Loan	500	SOFR (9) + 1.00%	2025
Houston Electric (3)	October 2024	General Mortgage Bonds	500	5.05%	2035
		Total Houston Electric	1,400		
CERC (4)	June 2024	Senior Notes	400	5.40%	2034
		Total CERC	400		
CenterPoint Energy (5)	May 2024	Senior Notes	700	5.40%	2029
CenterPoint Energy (6)	August 2024	First Mortgage Bonds	100	5.18%	2034
CenterPoint Energy (6)	August 2024	First Mortgage Bonds	60	5.28%	2036
CenterPoint Energy (7)	August 2024	Junior Subordinated Notes	400	7.00%	2055
CenterPoint Energy (7)	August 2024	Junior Subordinated Notes	400	6.85%	2055
CenterPoint Energy (8)	October 2024	Junior Subordinated Notes	500	6.70%	2055
		Total CenterPoint Energy	$ 3,960		

(1) Total proceeds from Houston Electric's February 2024 issuance of general mortgage bonds, net of transaction expenses and fees, were approximately $395 million, which were used for general limited liability company purposes, including capital expenditures and working capital purposes.
(2) On June 28, 2024, Houston Electric borrowed $100 million aggregate principal amount available under the term loan agreement. In September 2024, Houston Electric borrowed $200 million aggregate principal amount available under the term loan agreement. In November 2024, Houston Electric requested additional commitments under the term loan agreement and borrowed $200 million under the term loan agreement. Houston Electric has used the proceeds thereof for working capital purposes to support liquidity needs from the May 2024 Storm Events and general limited liability company purposes.
(3) Total net proceeds from Houston Electric's October 2024 issuance of general mortgage bonds, net of transaction expenses and fees, were approximately $494 million, which were used for general limited liability company purposes, including capital expenditures and working capital purposes.
(4) Total proceeds from CERC's June 2024 issuance of senior notes, net of transaction expenses and fees, were approximately $396 million which were used for general corporate purposes, including the repayment of a portion of CERC's outstanding commercial paper.
(5) Total proceeds from CenterPoint Energy's May 2024 issuance of senior notes, net of transaction expenses and fees, were approximately $693 million which were used for general corporate purposes including the redemption of $350 million aggregate principal amount of CenterPoint Energy's outstanding floating rate senior notes due 2024 and the repayment of a portion of CenterPoint Energy's outstanding commercial paper.
(6) Issued by SIGECO. Total proceeds from SIGECO's August 2024 issuance of first mortgage bonds, net of transaction expenses and fees, of approximately $159 million were used for general corporate purposes, including repaying short-term debt and long-term debt at maturity or otherwise. See Note 20 for additional information.
(7) Total proceeds from CenterPoint Energy's August 2024 issuance of junior subordinated notes, net of transaction expenses and fees, were approximately $790 million, which were used for general corporate purposes, including the

redemption of $500 million aggregate principal amount of CenterPoint Energy's outstanding 2.50% senior notes due 2024 and the repayment of a portion of CenterPoint Energy's outstanding commercial paper.

(8) Total proceeds from CenterPoint Energy's October 2024 issuance of junior subordinated notes, net of transaction expenses and fees, were approximately $494 million, which were used for general company purposes including the repayment of a portion of CenterPoint Energy's outstanding commercial paper.

(9) The borrowings under the term loan agreement bear interest at Houston Electric's option, at a rate equal to either (i) Term SOFR (as defined in the term loan agreement), which includes an adjustment of 0.10% per annum plus a margin of 1.0%, or (ii) the Alternate Base Rate (as defined in the term loan agreement)

Junior Subordinated Notes. As described in the table above, in August 2024, CenterPoint Energy issued $400 million aggregate principal amount of Junior Subordinated Series A Notes and $400 million aggregate principal amount of Junior Subordinated Series B Notes. Interest on the August Junior Subordinated Notes accrues from August 14, 2024 and is payable semiannually in arrears on February 15 and August 15 of each year, beginning on February 15, 2025, and maturing on February 15, 2055. The Junior Subordinated Series A Notes bear interest (i) from and including August 14, 2024 to, but excluding, February 15, 2030 at the rate of 7.000% per annum and (ii) from and including February 15, 2030, during each five-year period following February 15, 2030, at a rate per annum equal to the Five-Year Treasury Rate (as defined in the Junior Subordinated Notes Indenture) as of two business days prior to the beginning of the applicable Junior Subordinated Series A Interest Reset Period plus a spread of 3.254%, with such rate per annum to be reset on each five-year anniversary of February 15, 2030. The Junior Subordinated Series B Notes bear interest (i) from and including August 14, 2024, but excluding, February 15, 2035 at the rate of 6.850% per annum and (ii) from and including February 15, 2035, during each five-year period following February 15, 2035, at a rate per annum equal to the Five-Year Treasury Rate (as defined in the Junior Subordinated Notes Indenture) as of two business days prior to the beginning of the applicable Junior Subordinated Series B Interest Reset Period plus a spread of 2.946%, with such rate per annum to be reset on each five-year anniversary of February 15, 2035.

As described in the table above, in October 2024, CenterPoint Energy issued $500 million aggregate principal amount of Junior Subordinated Series C Notes. Interest on the Junior Subordinated Series C Notes accrues from October 31, 2024 and is payable semi-annually in arrears on May 15 and November 15 of each year, beginning on May 15, 2025, and maturing on May 15, 2055. The Junior Subordinated Series C Notes bear interest (i) from and including October 31, 2024 to, but excluding May 15, 2030 at the rate of 6.700% per annum and (ii) from and including May 15, 2030, during each five-year period following May 15, 2030 at a rate per annum equal to the Five-Year Treasury Rate (as defined in the Junior Subordinated Notes Indenture) as of two business days prior to the beginning of the applicable Junior Subordinated Series C Interest Reset Period plus a spread of 2.586%, with such rate per annum to be reset on each five-year anniversary of May 15, 2030.

So long as no event of default (as defined in the prospectus supplement relating to the offering of the Junior Subordinated Notes) with respect to a given series of Junior Subordinated Notes has occurred and is continuing, CenterPoint Energy may, at its option, defer interest payments on such series of Junior Subordinated Notes, from time to time, for one or more deferral periods of up to 20 consecutive semiannual interest payment periods, except that no such optional deferral period (as defined in the prospectus supplement relating to the offering of the Junior Subordinated Notes) may extend beyond the final maturity date of such series of Junior Subordinated Notes or end on a day other than the day immediately preceding an interest payment date.

During any optional deferral period, CenterPoint Energy (and its majority-owned subsidiaries, as applicable) will not (subject to certain exceptions as described in the Junior Subordinated Notes Indenture): (i) declare or pay any dividends or distributions on any of CenterPoint Energy's capital stock; (ii) redeem, purchase, acquire or make a liquidation payment with respect to any of CenterPoint Energy's capital stock; (iii) pay any principal, interest (to the extent such interest is deferrable) or premium on, or repay, repurchase or redeem any of CenterPoint Energy's indebtedness that ranks equally with or junior to the Junior Subordinated Notes in right of payment (including debt securities of other series, such as the other series of the Junior Subordinated Notes issued); or (iv) make any payments with respect to any guarantees by CenterPoint Energy of any indebtedness if such guarantees rank equally with or junior to the Junior Subordinated Notes in right of payment.

The Junior Subordinated Notes are CenterPoint Energy's unsecured obligations and rank junior and subordinate in right of payment to the prior payment in full of CenterPoint Energy's existing and future Senior Indebtedness (as defined in the Junior Subordinated Notes Indenture).

Convertible Senior Notes. Interest on the Convertible Notes is payable semiannually in arrears on February 15 and August 15 of each year, beginning on February 15, 2024. The Convertible Notes will mature on August 15, 2026, unless earlier converted or repurchased by CenterPoint Energy in accordance with their terms.

Prior to the close of business on the business day immediately preceding May 15, 2026, the Convertible Notes are convertible only under certain conditions. On or after May 15, 2026 until the close of business on the second scheduled trading

day immediately preceding the maturity date, holders of the Convertible Notes may convert all or any portion of their Convertible Notes at any time at the conversion rate then in effect, irrespective of the conditions. CenterPoint Energy may not redeem the Convertible Notes prior to the maturity date and no sinking fund is provided for the Convertible Notes.

Upon conversion of the Convertible Notes, CenterPoint Energy will pay cash up to the aggregate principal amount of the Convertible Notes to be converted and pay or deliver, as the case may be, cash, shares of Common Stock, or a combination of cash and shares of Common Stock, at CenterPoint Energy's election, in respect of the remainder, if any, of CenterPoint Energy's conversion obligation in excess of the aggregate principal amount of the Convertible Notes being converted. The conversion rate for the Convertible Notes is initially 27.1278 shares of Common Stock per $1,000 principal amount of Convertible Notes (equivalent to an initial conversion price of approximately $36.86 per share of Common Stock). The initial conversion price of the Convertible Notes represents a premium of approximately 25.0% over the last reported sale price of the Common Stock on the NYSE on August 1, 2023. Initially, a maximum of 33,909,700 shares of Common Stock may be issued upon conversion of the Convertible Notes based on the initial maximum conversion rate of 33.9097 shares of Common Stock per $1,000 principal amount of Convertible Notes. The conversion rate will be subject to adjustment in some events (as described in the Convertible Notes Indenture) but will not be adjusted for any accrued and unpaid interest.

In addition, following certain corporate events that occur prior to the maturity date of the Convertible Notes, CenterPoint Energy will, in certain circumstances, increase the conversion rate for a holder of Convertible Notes who elects to convert its Convertible Notes in connection with such a corporate event. If CenterPoint Energy undergoes a fundamental change (as defined in the Convertible Notes Indenture), holders of the Convertible Notes may require CenterPoint Energy to repurchase for cash all or any portion of their Convertible Notes at a fundamental change repurchase price equal to 100% of the principal amount of the Convertible Notes to be repurchased, plus accrued and unpaid interest to, but excluding, the fundamental change repurchase date.

The Convertible Notes are senior unsecured obligations of CenterPoint Energy and rank senior in right of payment to any of CenterPoint Energy's indebtedness that is expressly subordinated in right of payment to the Convertible Notes; equal in right of payment to any of CenterPoint Energy's unsecured indebtedness that is not so subordinated; effectively junior in right of payment to any of CenterPoint Energy's secured indebtedness it may incur in the future to the extent of the value of the assets securing such future secured indebtedness; and structurally junior to all indebtedness and other liabilities (including trade payables but excluding intercompany obligations and liabilities of a type not required to be reflected on a balance sheet of such subsidiaries in accordance with generally accepted accounting principles) of CenterPoint Energy's subsidiaries.

Debt Repayments and Redemptions. During 2024, the following debt instruments were repaid at maturity or redeemed prior to maturity:

Registrant	Repayment/ Redemption Date	Debt Instrument	Aggregate Principal	Interest Rate	Maturity Date
			(in millions)		
CenterPoint Energy (1)	March 2024	First Mortgage Bonds	$ 22	3.50%	2024
CenterPoint Energy (2)	May 2024	Senior Notes	350	SOFR + 0.65%	2024
CenterPoint Energy (3)	September 2024	Senior Notes	500	2.50%	2024
		Total CenterPoint Energy	$ 872		

(1) On February 6, 2024, SIGECO provided notice of redemption and on March 1, 2024, SIGECO paid down the outstanding principal of $22 million aggregate principal amount of SIGECO's outstanding first mortgage bonds due 2024 at a redemption price equal to 100% of the principal amount of the first mortgage bonds to be redeemed plus accrued and unpaid interest thereon, if any, to, but excluding, the redemption date.

(2) On May 13, 2024, CenterPoint Energy redeemed $350 million aggregate principal amount of its outstanding floating rate senior notes due 2024 at a redemption price equal to 100% of the principal amount to be redeemed plus accrued and unpaid interest thereon.

(3) In September 2024, CenterPoint Energy redeemed $500 million aggregate principal amount of its outstanding 2.50% senior notes due 2024 at a redemption price equal to 100% of the principal amount to be redeemed plus accrued and unpaid interest thereon.

CenterPoint Energy and Houston Electric recorded the following losses on early extinguishment of debt, including make-whole premiums and recognition of deferred debt related costs, in Interest expense and other finance charges on their respective Statements of Consolidated Income unless specified otherwise:

	Year Ended December 31,		
	2024	2023	2022
		(in millions)	
CenterPoint Energy (1)	$ —	$ 11	$ 47
Houston Electric (2)	—	—	2

(1) The loss on early extinguishment of debt at CenterPoint Energy during 2023 was recorded as a regulatory asset.
(2) The loss on early extinguishment of debt at Houston Electric during 2022 was recorded as a regulatory asset.

Securitization Bonds. As of December 31, 2024, CenterPoint Energy, Houston Electric and SIGECO had special purpose subsidiaries including the Bond Companies and the SIGECO Securitization Subsidiary, which are consolidated. The consolidated special purpose subsidiaries are wholly-owned, bankruptcy remote entities that were formed solely for the purpose of securitizing transition property or facilitating the securitization financing of qualified costs in the second quarter of 2023 associated with the completed retirement of SIGECO's A.B. Brown coal generation facilities through the issuance of securitization bonds and activities incidental thereto. The Securitization Bonds issued by Bond Company IV are payable only through the imposition and collection of transition charges, as defined in the Texas Public Utility Regulatory Act, which are irrevocable, non-bypassable charges to provide recovery of authorized qualified costs. The SIGECO Securitization Bonds are payable only through the imposition of securitization charges payable by SIGECO's retail electric customers, which are non-bypassable charges to provide recovery of the qualified costs of SIGECO authorized by the IURC order. CenterPoint Energy, Houston Electric and SIGECO have no payment obligations in respect of the Securitization Bonds issued by Bond Company IV or the SIGECO Securitization Bonds other than to remit the applicable transition or securitization charges they collect as set forth in servicing agreements among Houston Electric, the Bond Companies, SIGECO, the SIGECO Securitization Subsidiary and other parties. Each special purpose entity is the sole owner of the right to impose, collect and receive the applicable transition and securitization charges securing the bonds issued by that entity. Creditors of CenterPoint Energy, Houston Electric and SIGECO have no recourse to any assets or revenues of the Bond Companies (including the transition charges) or the SIGECO Securitization Subsidiary, as applicable, and the bondholders have no recourse to the to the general credit of CenterPoint Energy, Houston Electric or SIGECO.

Credit Facilities. The Registrants had the following revolving credit facilities as of December 31, 2024:

Registrant	Execution Date	Size of Facility	Draw Rate of SOFR plus (1)	Financial Covenant Limit on Debt for Borrowed Money to Capital Ratio		Debt for Borrowed Money to Capital Ratio as of December 31, 2024 (2)	Termination Date (5)
		(in millions)					
CenterPoint Energy	December 6, 2022	$ 2,400	1.500%	65%	(3)	59.3%	December 6, 2027
CenterPoint Energy (4)	December 6, 2022	250	1.125%	65%		44.8%	December 6, 2027
Houston Electric	December 6, 2022	300	1.250%	67.5%	(3)	53.3%	December 6, 2027
CERC	December 6, 2022	1,050	1.125%	65%		41.4%	December 6, 2027
Total		$ 4,000					

(1) Based on credit ratings as of December 31, 2024.
(2) As defined in the revolving credit facility agreement, excluding Securitization Bonds.
(3) For CenterPoint Energy and Houston Electric, the financial covenant limit will temporarily increase to 70% if Houston Electric experiences damage from a natural disaster in its service territory and CenterPoint Energy certifies to the administrative agent that Houston Electric has incurred system restoration costs reasonably likely to exceed $100 million in a consecutive 12-month period, all or part of which Houston Electric intends to seek to recover through securitization financing. Such temporary increase in the financial covenant would be in effect from the date CenterPoint Energy delivers its certification until the earliest to occur of (i) the completion of the securitization financing, (ii) the first anniversary of CenterPoint Energy's certification or (iii) the revocation of such certification.
(4) This credit facility was issued by SIGECO.

(5) See Note 20 for discussion of subsequent events associated with the revolving credit facilities.

The Registrants, as well as the subsidiaries of CenterPoint Energy discussed above, were in compliance with all financial debt covenants as of December 31, 2024.

As of December 31, 2024 and 2023, the Registrants had the following revolving credit facilities and utilization of such facilities:

	December 31, 2024					December 31, 2023				
Registrant	Size of Facility	Loans	Letters of Credit	Commercial Paper	Weighted Average Interest Rate	Size of Facility	Loans	Letters of Credit	Commercial Paper	Weighted Average Interest Rate
	(in millions, except weighted average interest rate)									
CenterPoint Energy (1)	$ 2,400	$ —	$ —	$ 382	4.59 %	$ 2,400	$ —	$ —	$ 1,036	5.54 %
CenterPoint Energy (2)	250	—	—	—	— %	250	—	—	—	— %
Houston Electric	300	—	—	—	— %	300	—	—	—	— %
CERC	1,050	—	—	599	4.62 %	1,050	—	1	484	5.53 %
Total	$ 4,000	$ —	$ —	$ 981		$ 4,000	$ —	$ 1	$ 1,520	

(1) CenterPoint Energy's and CERC's outstanding commercial paper generally have maturities up to 60 days and 30 days, respectively, and are backstopped by the respective issuer's long-term revolving credit facility.
(2) This credit facility was issued by SIGECO.

Maturities. As of December 31, 2024, maturities of long-term debt through 2029, excluding the ZENS obligation and unamortized discounts, premiums and issuance costs, were as follows:

	CenterPoint Energy (1)	Houston Electric (1)	CERC	Securitization Bonds
		(in millions)		
2025	$ 564	$ 500	$ 10	$ 13
2026	2,274	300	60	14
2027	1,320	300	625	14
2028	2,063	500	1,230	15
2029	935	—	30	16

(1) These maturities include Securitization Bonds principal repayments on scheduled payment dates.

Liens. As of December 31, 2024, Houston Electric's assets were subject to liens securing approximately $8.4 billion of general mortgage bonds outstanding under the General Mortgage, including approximately $68 million held in trust to secure pollution control bonds that mature in 2028 for which CenterPoint Energy is obligated. The general mortgage bonds that are held in trust to secure pollution control bonds are not reflected in Houston Electric's consolidated financial statements because of the contingent nature of the obligations. Houston Electric may issue additional general mortgage bonds on the basis of retired bonds, 70% of property additions or cash deposited with the trustee. As of December 31, 2024, approximately $4.7 billion of additional general mortgage bonds could be issued on the basis of retired bonds and 70% of property additions. No first mortgage bonds are outstanding under the M&DOT, and Houston Electric is contractually obligated to not issue any additional first mortgage bonds under the M&DOT and is undertaking actions to release the lien of the M&DOT and terminate the M&DOT.

As of December 31, 2024, SIGECO had approximately $985 million aggregate principal amount of first mortgage bonds outstanding. Generally, all of SIGECO's real and tangible property is subject to the lien of SIGECO's mortgage indenture which was amended and restated effective as of January 1, 2023. As of December 31, 2024, SIGECO was permitted to issue additional bonds under its mortgage indenture up to 70% of then currently unfunded property additions and approximately $899 million of additional first mortgage bonds could be issued on this basis.

Houston Electric and CERC participate in a money pool through which they can borrow or invest on a short-term basis. For additional information, see Note 18.

(13) Income Taxes

The components of the Registrants' income tax expense (benefit) were as follows for the periods presented:

	Year Ended December 31,		
	2024	2023	2022
		(in millions)	
CenterPoint Energy			
Current income tax expense (benefit):			
Federal	$ (17)	$ 106	$ 294
State	(9)	33	46
Total current expense (benefit)	(26)	139	340
Deferred income tax expense (benefit):			
Federal	218	119	16
State	3	(88)	4
Total deferred expense	221	31	20
Total income tax expense	$ 195	$ 170	$ 360
Houston Electric			
Current income tax expense (benefit):			
Federal	$ 62	$ (26)	$ 23
State	15	34	16
Total current expense	77	8	39
Deferred income tax expense:			
Federal	60	159	86
State	1	1	—
Total deferred expense	61	160	86
Total income tax expense	$ 138	$ 168	$ 125
CERC			
Current income tax expense (benefit):			
Federal	$ 55	$ 12	$ 30
State	(6)	3	28
Total current expense	49	15	58
Deferred income tax expense (benefit):			
Federal	60	95	164
State	(5)	(136)	14
Total deferred expense (benefit)	55	(41)	178
Total income tax expense (benefit)	$ 104	$ (26)	$ 236

A reconciliation of income tax expense (benefit) using the federal statutory income tax rate to the actual income tax expense and resulting effective income tax rate were as follows:

	Year Ended December 31,		
	2024	2023	2022
	(in millions)		
CenterPoint Energy (1) (2) (3)			
Income before income taxes	$ 1,214	$ 1,087	$ 1,417
Federal statutory income tax rate	21 %	21 %	21 %
Expected federal income tax expense	255	228	298
Increase (decrease) in tax expense resulting from:			
State income tax expense, net of federal income tax	25	25	46
State valuation allowance, net of federal income tax	17	—	—
State law change, net of federal income tax	(47)	(69)	—
Equity AFUDC	(12)	(13)	(8)
Excess deferred income tax amortization	(43)	(44)	(51)
Goodwill impairment	—	—	84
Sale of Energy Systems Group	—	28	—
Other, net	—	15	(9)
Total	(60)	(58)	62
Total income tax expense	$ 195	$ 170	$ 360
Effective tax rate	16 %	16 %	25 %
Houston Electric (4) (5) (6)			
Income before income taxes	$ 684	$ 761	$ 635
Federal statutory income tax rate	21 %	21 %	21 %
Expected federal income tax expense	144	160	133
Increase (decrease) in tax expense resulting from:			
State income tax expense, net of federal income tax	12	27	13
Equity AFUDC	(5)	—	—
Excess deferred income tax amortization	(17)	(17)	(18)
Other, net	4	(2)	(3)
Total	(6)	8	(8)
Total income tax expense	$ 138	$ 168	$ 125
Effective tax rate	20 %	22 %	20 %
CERC (7) (8) (9)			
Income before income taxes	$ 644	$ 486	$ 961
Federal statutory income tax rate	21 %	21 %	21 %
Expected federal income tax expense	135	102	202
Increase (decrease) in tax expense resulting from:			
State income tax expense, net of federal income tax	19	(40)	35
State law change, net of federal income tax	(45)	(66)	—
State valuation allowance, net of federal income tax	17	—	—
Goodwill impairment	—	—	30
Equity AFUDC	(4)	—	—
Excess deferred income tax amortization	(15)	(23)	(28)
Other, net	(3)	1	(3)
Total	(31)	(128)	34
Total income tax expense (benefit)	$ 104	$ (26)	$ 236
Effective tax rate	16 %	(5)%	25 %

(1) Recognized a $47 million benefit for the impact of state apportionment changes and Louisiana statutory rate change that resulted in the remeasurement of state deferred taxes, a $43 million benefit for the amortization of the net regulatory EDIT liability as decreed by regulators in certain jurisdictions, a $17 million valuation allowance established against Louisiana and Mississippi NOL, since those NOLs will not be utilized due to the Louisiana and Mississippi natural gas LDC businesses sale and a $12 million benefit for the impact of AFUDC equity.

(2) Recognized a $69 million benefit for the impact of state apportionment changes that resulted in the remeasurement of state deferred taxes of the unitary group, a $44 million benefit for the amortization of the net regulatory EDIT liability as decreed by regulators in certain jurisdictions, a $13 million benefit for the impact of AFUDC equity, and a $28 million expense for the gain on the Energy Systems Group sale.

(3) Recognized a $51 million benefit for the amortization of the net regulatory EDIT liability as decreed by regulators in certain jurisdictions, an $8 million benefit for the impact of AFUDC equity, and a $84 million expense for the goodwill impairment on the Arkansas and Oklahoma Natural Gas business sale.

(4) Recognized a $17 million benefit for the amortization of the net regulatory EDIT liability as decreed by regulators in Texas.

(5) Recognized a $17 million benefit for the amortization of the net regulatory EDIT liability as decreed by regulators in certain jurisdictions.

(6) Recognized a $18 million benefit for the amortization of the net regulatory EDIT liability as decreed by regulators in certain jurisdictions.

(7) Recognized a $45 million benefit for the impact of state apportionment changes and Louisiana statutory rate change that resulted in the remeasurement of state deferred taxes, a $17 million valuation allowance established against Louisiana and Mississippi NOL, since those NOLs will not be utilized due to the Louisiana and Mississippi natural gas LDC businesses sale, and a $15 million benefit for the amortization of the net regulatory EDIT liability as decreed by regulators in certain jurisdictions.

(8) Recognized a $66 million benefit for the impact of state apportionment changes that resulted in the remeasurement of state deferred taxes of the unitary group, and a $23 million benefit for the amortization of the net regulatory EDIT liability as decreed by regulators in certain jurisdictions.

(9) Recognized a $28 million benefit for the amortization of the net regulatory EDIT liability as decreed by regulators in certain jurisdictions, and a $30 million expense for the goodwill impairment on the Arkansas and Oklahoma Natural Gas business sale.

The tax effects of temporary differences that gave rise to significant portions of deferred tax assets and liabilities were as follows:

	December 31, 2024	December 31, 2023
	(in millions)	
CenterPoint Energy		
Deferred tax assets:		
Benefits and compensation	$ 126	$ 131
Regulatory liabilities	348	365
Loss and credit carryforwards	942	76
Asset retirement obligations	98	96
Other	150	124
Valuation allowance	(35)	(10)
Total deferred tax assets	1,629	782
Deferred tax liabilities:		
Property, plant and equipment	4,384	3,580
Regulatory assets	750	401
Investment in ZENS and equity securities related to ZENS	866	788
Other	18	92
Total deferred tax liabilities	6,018	4,861
Net deferred tax liabilities	$ 4,389	$ 4,079
Houston Electric		
Deferred tax assets:		
Benefits and compensation	$ 8	$ 10
Regulatory liabilities	158	176
Loss and credit carryforward	408	—
Asset retirement obligations	9	6
Other	16	18
Total deferred tax assets	599	210
Deferred tax liabilities:		
Property, plant and equipment	1,988	1,497
Regulatory assets	113	119
Total deferred tax liabilities	2,101	1,616
Net deferred tax liabilities	$ 1,502	$ 1,406
CERC		
Deferred tax assets:		
Benefits and compensation	$ 17	$ 21
Regulatory liabilities	150	145
Loss and credit carryforwards	694	276
Asset retirement obligations	82	86
Other	122	65
Valuation allowance	(25)	—
Total deferred tax assets	1,040	593
Deferred tax liabilities:		
Property, plant and equipment	1,883	1,602
Regulatory assets	513	171
Other	14	66
Total deferred tax liabilities	2,410	1,839
Net deferred tax liabilities	$ 1,370	$ 1,246

Tax Attribute Carryforwards and Valuation Allowance. As of December 31, 2024, CenterPoint Energy has federal NOL carryforwards of $3.3 billion, which have an indefinite carryforward period. As of December 31, 2024, CenterPoint Energy has federal charitable contribution carryforwards of $51 million which expire between 2029 and 2030. As of December 31, 2024, CenterPoint Energy has federal corporate alternative minimum tax carryforwards of $124 million which have an indefinite carryforward period. As of December 31, 2024, CenterPoint Energy has $2.1 billion of gross state NOL carryforwards which

expire between 2025 and 2043, and $3 million of state tax credits, net of valuation allowance, which do not expire. CenterPoint Energy reported a valuation allowance against certain state NOL and credit carryforwards because it is more likely than not that the benefit will not be realized.

As of December 31, 2024, Houston Electric has $1.7 billion of federal NOL carryforwards which have an indefinite carryforward period. As of December 31, 2024, Houston Electric has federal corporate alternative minimum tax carryforwards of $48 million which have an indefinite carryforward period.

As of December 31, 2024, CERC has federal NOL carryforwards of $2.3 billion which have an indefinite carryforward period. As of December 31, 2024, CERC has federal corporate alternative minimum tax carryforwards of $101 million which have an indefinite carryforward period. As of December 31, 2024, CERC has $1.2 billion of gross state NOL carryforwards which expire between 2025 and 2043, and $3 million of state tax credits, net of valuation allowance, which do not expire.

A reconciliation of CenterPoint Energy's beginning and ending balance of unrecognized tax benefits, excluding interest and penalties, are as follows for the periods presented:

	Year Ended December 31,		
	2024	2023	2022
	(in millions)		
Balance, beginning of year	$ 25	$ 26	$ 3
Increases related to tax positions of prior years	—	—	26
Decreases related to tax positions of prior years	—	—	(3)
Lapse of statute of limitations	—	(1)	—
Balance, end of year	$ 25	$ 25	$ 26

As of December 31, 2024, CenterPoint Energy reported net unrecognized tax benefits, including penalties and interest, of $32 million which were included in Other non-current liabilities in the Consolidated Balance Sheets. Included in the balance of uncertain tax positions as of December 31, 2024 were $25 million of tax benefits that, if recognized, would affect the effective tax rate. The Registrants recognize interest accrued related to unrecognized tax benefits and penalties as income tax expense. The above table does not include $7 million of accrued penalties and interest as of December 31, 2024. The Registrants believe that it is reasonably possible that there will be a $10 million decrease in unrecognized tax benefits, including penalties and interest, in the next 12 months as a result of a lapse of statutes on older exposures, a tax settlement, and/or a resolution of open audits.

Tax Audits and Settlements. Tax years through 2022 have been audited and settled with the IRS for CenterPoint Energy. For tax years 2023 and 2024, the Registrants are participants in the IRS's Compliance Assurance Process.

(14) Commitments and Contingencies

(a) Purchase Obligations (CenterPoint Energy and CERC)

Commitments include minimum purchase obligations related to CenterPoint Energy's and CERC's Natural Gas reportable segment and CenterPoint Energy's Electric reportable segment. Contracts with minimum payment obligations have various quantity requirements and durations and are not classified as non-trading derivative assets and liabilities in CenterPoint Energy's and CERC's Consolidated Balance Sheets as of December 31, 2024 and 2023 because these contracts meet an exception as "normal purchases contracts" or do not meet the definition of a derivative. Natural gas and coal supply commitments also include transportation contracts that do not meet the definition of a derivative.

On February 1, 2023, Indiana Electric entered into an amended and restated BTA to purchase the 191 MW Posey Solar project for a fixed purchase price over the anticipated 35-year life. On February 7, 2023, Indiana Electric filed a CPCN with the IURC to approve the amended BTA. With the passage of the IRA, Indiana Electric can now pursue PTCs for solar projects. Indiana Electric filed the updated CPCN with a request that project costs, net of PTCs, be recovered in rate base, through base rates or the CECA mechanism, depending on which provides more timely recovery. On September 6, 2023, the IURC issued an order approving the CPCN. The Posey Solar project is expected to be placed in service in the second quarter of 2025. See Note 20 for additional details.

On January 11, 2023, the IURC issued an order approving the settlement agreement granting Indiana Electric a CPCN to purchase and acquire the 130 MW Pike County solar project through a BTA and approved the estimated cost. The IURC also

designated the project as a clean energy project as well as approved the proposed levelized rate and associated ratemaking and accounting treatment. Due to inflationary pressures, the developer disclosed that costs exceeded the agreed upon levels in the BTA. After negotiations, Indiana Electric and the developer were not able to agree upon updated pricing. As a result, on March 15, 2024, Indiana Electric provided notice to the IURC that it was exercising its right to terminate the BTA, which terminated all further obligations of Indiana Electric with respect to the project.

As of December 31, 2024, CenterPoint Energy and CERC had the following undiscounted minimum purchase obligations:

	CenterPoint Energy			CERC
	Natural Gas Supply	Electric Supply (1)	Other (2)	Natural Gas Supply
		(in millions)		
2025	$ 635	$ 83	$ 95	$ 631
2026	601	130	100	597
2027	517	135	18	513
2028	473	97	8	470
2029	459	94	2	456
Thereafter	1,566	1,303	190	1,544
Total	$ 4,251	$ 1,842	$ 413	$ 4,211

(1) Related to PPAs with commitments ranging from 15 years to 25 years.

(2) Related primarily to technology hardware and software agreements.

Excluded from the table above are estimates for cash outlays from other PPAs through Indiana Electric that do not have minimum thresholds but require payment when energy is generated by the provider. Costs arising from certain of these commitments are pass-through costs, generally collected dollar-for-dollar from retail customers through regulator-approved cost recovery mechanisms.

(b) AMAs (CenterPoint Energy and CERC)

CenterPoint Energy's and CERC's Natural Gas businesses continue to utilize AMAs associated with their utility distribution service in Indiana, Louisiana, Minnesota, Mississippi and Texas. The AMAs have varying terms, the longest of which expires in 2029. Pursuant to the provisions of the agreements, CenterPoint Energy's and CERC's Natural Gas either sells natural gas to the asset manager and agrees to repurchase an equivalent amount of natural gas throughout the year at the same cost, or simply purchases its full natural gas requirements at each delivery point from the asset manager. Generally, AMAs are contracts between CenterPoint Energy's and CERC's Natural Gas and an asset manager that are intended to transfer the working capital obligation and maximize the utilization of the assets. In these agreements, CenterPoint Energy's and CERC's Natural Gas agrees to release transportation and storage capacity to other parties to manage natural gas storage, supply and delivery arrangements for CenterPoint Energy's and CERC's Natural Gas and to use the released capacity for other purposes when it is not needed for CenterPoint Energy's and CERC's Natural Gas. CenterPoint Energy's and CERC's Natural Gas may receive compensation from the asset manager through payments made over the life of the AMAs. CenterPoint Energy's and CERC's Natural Gas has an obligation to purchase their winter storage requirements that have been released to the asset manager under these AMAs. For amounts outstanding under these AMAs, see Note 12.

(c) Guarantees (CenterPoint Energy)

CenterPoint Energy recognizes guarantee obligations at fair value. CenterPoint Energy discloses parent company guarantees of a subsidiary's obligation when that guarantee results in the exposure of a material obligation of the parent company even if the probability of fulfilling such obligation is considered remote.

On May 21, 2023, CenterPoint Energy, through Vectren Energy Services, entered into the Equity Purchase Agreement to sell Energy Systems Group. The sale closed on June 30, 2023. See Note 4 for further information.

In the normal course of business prior to the consummation of the transaction on June 30, 2023, CenterPoint Energy, primarily through Vectren, issued parent company level guarantees supporting Energy Systems Group's obligations. When Energy Systems Group was wholly-owned by CenterPoint Energy, these guarantees did not represent incremental consolidated obligations, but rather, these guarantees represented guarantees of Energy Systems Group's obligations to allow it to conduct business without posting other forms of assurance. For those obligations where potential exposure can be estimated, management estimates the maximum exposure under these guarantees to be approximately $465 million as of December 31, 2024 and expects the exposure to decrease pro rata. This exposure primarily relates to energy savings guarantees on federal

energy savings performance contracts. Other parent company level guarantees, certain of which do not contain a cap on potential liability, were issued prior to the sale of Energy Systems Group in support of federal operations and maintenance projects for which a maximum exposure cannot be estimated based on the nature of the projects.

Under the terms of the Equity Purchase Agreement, ESG Holdings Group must generally use reasonable best efforts to replace existing CenterPoint Energy guarantees with credit support provided by a party other than CenterPoint Energy as of and after the closing of the transaction. The Equity Purchase Agreement also requires certain protections to be provided for any damages incurred by CenterPoint Energy in relation to these guarantees not released by closing. No additional guarantees were provided by CenterPoint Energy in favor of Energy Systems Group subsequent to the closing of the sale on June 30, 2023.

While there can be no assurance that performance under any of these parent company guarantees will not be required in the future, CenterPoint Energy considers the likelihood of a material amount being incurred to be remote. CenterPoint Energy believes that, from Energy Systems Group's inception in 1994 to the closing of the sale of Energy Systems Group on June 30, 2023, Energy Systems Group had a history of generally meeting its performance obligations and energy savings guarantees and its installed products operated effectively. CenterPoint Energy recorded no amounts on its Consolidated Balance Sheets as of December 31, 2024 and 2023 related to its obligation under the outstanding guarantees.

(d) Legal, Environmental and Other Matters

Legal Matters

Litigation Related to Hurricane Beryl. Various federal, state and local governmental and regulatory agencies and other entities, such as the Texas Governor's office, the Texas legislature and the PUCT, have called for or are conducting inquiries and investigations into Hurricane Beryl, the efforts made by Houston Electric to prepare for, and respond to, this event, including the electric service outage issues, and the procurement of TEEEF. Moreover, additional governmental and regulatory agencies and other entities may conduct such inquiries and investigations, as well. There are significant uncertainties around these inquiries and investigations and potential results and consequences, including with respect to our recovery of costs incurred as a result of Hurricane Beryl and whether any financial penalties will be assessed or changes to Houston Electric's system, service territories, operations and/or regulatory treatment will result therefrom. Further, on January 22, 2025, a putative shareholder of CenterPoint Energy, Donel Davidson, filed a derivative petition in Harris County District Court, Texas, alleging breach of fiduciary duty and unjust enrichment on behalf of CenterPoint Energy against certain of its current and former directors and officers citing, in part, the topics of these inquiries and investigations. The action seeks to recover damages and other relief from the defendants on behalf of CenterPoint Energy. Additionally, on February 12, 2025, a second putative shareholder of CenterPoint Energy made a demand on the Board to investigate the same basic allegations raised in the derivative petition filed by Donel Davidson.

CenterPoint Energy and Houston Electric are subject to current and potential future litigation and claims arising out of Hurricane Beryl, which litigation and claims could include allegations of, among other things, personal injury, property damage, various economic losses in connection with loss of power, unlawful business practices, and others. As of December 31, 2024, three putative class actions had been filed against CenterPoint Energy and/or Houston Electric in the District Courts of Harris County, Texas, on behalf of individuals or entities who claim losses due to power outages lasting at least 48 hours as a result of Hurricane Beryl, such actions consisting of the following proposed classes: (1) all restaurants in Harris County, Galveston County, and Montgomery County; (2) all residential customers; and (3) all health, wellness, medical and beauty facilities in Harris County. These putative classes assert claims and theories of negligence, gross negligence, nuisance, fraud, and/or violation of Houston Electric's tariff for retail delivery service, and each seeks damages in excess of $100 million for, among other things, business interruption, property damage and loss, cost of repair, loss of use and market value, lost income, nuisance, extreme mental anguish and/or punitive damages. In addition, as of December 31, 2024, two individual actions had been filed in Harris County District Courts asserting claims of negligence, negligence per se and/or gross negligence against CenterPoint Energy and Houston Electric. The plaintiffs in these actions allege personal injury and/or property damage from downed power lines and seek damages in excess of $1 million. CenterPoint Energy and Houston Electric intend to vigorously defend themselves against the lawsuits. CenterPoint Energy and its subsidiaries have general and excess liability insurance policies that provide coverage for third party bodily injury and property damage claims. Given the nature of some allegations, it is possible that the insurers could dispute coverage for some types of claims or damages that may be alleged by plaintiffs, and CenterPoint Energy has received from two insurers denials of indemnity coverage in the putative class actions based on the failure to supply exclusion. Those insurers have also reserved their rights with respect to coverage in those actions. CenterPoint Energy and Houston Electric intend to continue to pursue all available insurance coverage for all of these matters. To date, there have not been demands, quantification, disclosure or discovery of damages by any party to any of the above legal matters that are sufficient to enable CenterPoint Energy and its subsidiaries to estimate exposure. Given that, as well as the preliminary nature of the proceedings, the numerosity of parties and complexity of issues involved, and the uncertainties of

litigation, CenterPoint Energy and its subsidiaries are unable to predict the outcome or consequences of any of the foregoing matters or to estimate a range of potential losses. For more information regarding Hurricane Beryl, see Note 7.

Litigation Related to the February 2021 Winter Storm Event. Various legal proceedings are still pending against numerous entities with respect to the February 2021 Winter Storm Event, including against CenterPoint Energy, Utility Holding, Houston Electric, and CERC. Like other Texas energy companies and TDUs, CenterPoint Energy and Houston Electric have become involved in certain investigations, litigation and other regulatory and legal proceedings regarding their efforts to restore power during the storm and their compliance with NERC, ERCOT and PUCT rules and directives. Additionally, like other natural gas market participants, CERC has been named in litigation alleging gas market manipulation.

CenterPoint Energy, Utility Holding, and Houston Electric, along with hundreds of other defendants (including ERCOT, power generation companies, other TDUs, natural gas producers, REPs, and other entities) received claims and lawsuits filed by plaintiffs alleging wrongful death, personal injury, property damage and other injuries and damages. As of December 31, 2024, there were approximately 220 pending lawsuits that are consolidated in Texas state court in Harris County, Texas, as part of the MDL proceeding related to the February 2021 Winter Storm Event, and CenterPoint Energy and Houston Electric, along with numerous other entities, have been named as defendants in approximately 155 of those lawsuits. One of the lawsuits in the MDL is a putative class action on behalf of everyone who received electric power via the ERCOT grid and sustained a power outage between February 10, 2021 and February 28, 2021. Additionally, Utility Holding is currently named as a defendant in one lawsuit in which CenterPoint Energy and Houston Electric are also named as defendants.

The judge overseeing the MDL issued an initial case management order and stayed all proceedings and discovery. Per the case management order, the judge entertained dispositive motions in five representative or "bellwether" cases and, in late January 2023, issued rulings on them. The judge ruled that ERCOT has sovereign immunity as a governmental entity and dismissed the suits against it. In a subsequent opinion in an unrelated matter, the Texas Supreme Court held that ERCOT is entitled to sovereign immunity. This ruling will apply to claims against ERCOT in the MDL. The MDL judge also dismissed all claims against the natural gas defendants (which list of natural gas defendants incorrectly included Utility Holding) and the REP defendants and some causes of action against the other defendants. CenterPoint Energy expects that the claims against Utility Holding will ultimately be dismissed in light of the judge's initial rulings. As to the TDU and generator defendants, the judge dismissed some causes of action but denied the motions to dismiss claims for negligence, gross negligence, and nuisance, which denial the TDU defendants and generator defendants asked the courts of appeals to overturn. On April 2, 2024, a three-judge panel of the Court of Appeals for the Fourteenth District of Texas issued an opinion in the TDU mandamus proceeding, granting in part and denying in part the TDUs' mandamus request. In its opinion, the panel granted the TDUs' mandamus request relating to the TDUs' motion to dismiss the plaintiffs' claims for (1) negligence, (2) negligent nuisance and (3) strict liability nuisance and ordered those claims be dismissed. The panel denied the TDUs' mandamus request relating to the TDUs' motion to dismiss the plaintiffs' gross negligence and intentional nuisance claims. On May 22, 2024, the TDUs filed a mandamus petition with the Supreme Court of Texas, seeking dismissal of the remaining claims. The Supreme Court of Texas subsequently asked for briefing on the merits and, on December 20, 2024, set the TDUs' mandamus petition for oral argument, which occurred on February 19, 2025.

In the generator mandamus proceeding that was pending in the Court of Appeals for the First District of Texas, a three-judge panel granted the generators' mandamus request and ordered dismissal of all claims asserted against the generators' defendants. The plaintiffs asked the entire First Court of Appeals to rehear the panel's decision. On November 26, 2024, the First Court of Appeals denied that motion. The plaintiffs filed a petition for writ of mandamus with the Supreme Court of Texas on January 31, 2025.

The MDL judge allowed defendants (including Houston Electric) to file several additional motions on preliminary legal issues. These motions included the TDUs' motion to dismiss under Chapter 150 of the Texas Civil Practice and Remedies Code, which was filed in one of the bellwether cases and argued that all of plaintiffs' claims should be dismissed because the plaintiffs did not include a sufficient certificate by a qualified engineer with their petition, as required by Texas law, as well as a motion to deny class certification in the putative class action. On November 13, 2024, the MDL Court granted the TDUs' motion to dismiss under Chapter 150, and on December 3, 2024, the plaintiffs filed a notice of appeal of that ruling. On January 8, 2025, the MDL Court denied class certification in the putative class action. Following issuance of the order denying class certification, a new lawsuit was filed on behalf of approximately 140 plaintiffs in Harris County District Court against hundreds of defendants, including CenterPoint Energy and Houston Electric. In addition, plaintiffs filed a notice of appeal of the denial of class certification on January 27, 2025. Aside from addressing certain additional preliminary legal issues, the cases remain stayed in the MDL Court. CenterPoint Energy, Utility Holding, and Houston Electric intend to vigorously defend themselves against the claims raised.

CenterPoint Energy and Houston Electric have also responded to inquiries from the Texas Attorney General and the Galveston County District Attorney's Office, and various other regulatory and governmental entities also conducted inquiries, investigations and other reviews of the February 2021 Winter Storm Event and the efforts made by various entities to prepare for, and respond to, the event, including the electric generation shortfall issues.

In February 2023, twelve lawsuits were filed in state district court in Harris County and Tom Green County, Texas, against dozens of gas market participants in Texas, including natural gas producers, processors, pipelines, marketers, sellers, traders, gas utilities, and financial institutions. Plaintiffs named CERC as a defendant, along with "CenterPoint Energy Services, Inc.," incorrectly identifying it as CERC's parent company (CenterPoint Energy previously divested CenterPoint Energy Services, Inc.). One lawsuit filed in Harris County is a putative class action on behalf of two classes of electric and natural gas customers (those who experienced a loss of electricity and/or natural gas, and those who were charged securitization-related surcharges on a utility bill or were otherwise charged higher rates for electricity and/or gas during the February 2021 Winter Storm Event), potentially including millions of class members. Two other lawsuits (one filed in Harris County and one in Tom Green County) were brought by an entity that purports to be an assignee of the claims of tens of thousands of persons and entities. These, and nine other similar lawsuits filed in Harris County, generally allege that the defendants engaged in gas market manipulation and price gouging, including by intentionally withholding, suppressing, or diverting supplies of natural gas in connection with the February 2021 Winter Storm Event, Winter Storm Elliott, and other severe weather conditions, and through financial market manipulation. Plaintiffs allege that this manipulation impacted gas supply and prices as well as the market, supply, and price of electricity in Texas and caused blackouts and other damage. Plaintiffs assert claims for tortious interference with existing contract, private nuisance, and unjust enrichment, and allege a broad array of injuries and damages, including personal injury, property damage, and harm from certain costs being securitized and passed on to ratepayers. The lawsuits do not specify the amount of damages sought, but seek broad categories of actual, compensatory, statutory, consequential economic, and punitive damages; restitution and disgorgement; pre- and post-judgment interest; costs and attorneys' fees; and other relief. All twelve lawsuits have been tagged for transfer to the existing MDL proceeding referenced above, but only three of the cases have been served against the defendants, including CERC. These gas market cases are in addition to the 220 cases noted above regarding electric market issues.

On February 2, 2024, CERC filed pleas to the jurisdiction in the three cases in which it was served; CERC also partially joined the other defendants' motions to dismiss and additional pleas to the jurisdiction. On April 2, 2024, plaintiffs in the three served cases filed amended petitions rather than responding to pleas to the jurisdiction and motions to dismiss. Among other changes, plaintiffs in these three cases dismissed CenterPoint Energy Services, Inc., but maintained the same three causes of action as to the remaining defendants. CERC has vigorously defended itself against the claims raised, including filing updated pleas to the jurisdiction on May 17, 2024 in response to plaintiffs' amended petitions – and will continue to do so. On August 12, 2024, plaintiffs in the putative class action filed a motion for leave to amend to add additional plaintiffs/class representatives. Defendants opposed this motion on September 20, 2024. On September 23, 2024, the MDL judge heard oral argument on CERC's plea to the jurisdiction and defendants' motions to dismiss and other pleas to the jurisdiction. On November 7, 2024 and November 11, 2024, the MDL judge granted defendants' motion to dismiss and CERC's plea to the jurisdiction in all three cases. As a result of these rulings, all claims against CERC were dismissed with prejudice. Plaintiffs have appealed these rulings, and the appeals have been assigned to the Court of Appeals for the First District of Texas. On December 4, 2024, the MDL judge denied as moot plaintiff's motion for leave to amend to add additional plaintiffs/class representatives in the putative class action case. On January 17, 2025, the plaintiffs in the putative class action case filed an unopposed motion to dismiss their appeal, which the Court of Appeals granted on February 4, 2025, dismissing the appeal. Plaintiffs' opening briefs in the remaining two cases are scheduled to be filed on March 28, 2025.

To date, there have not been demands, quantification, disclosure or discovery of damages by any party to any of the above legal matters that are sufficient to enable CenterPoint Energy and its subsidiaries to estimate exposure. Given that, as well as the preliminary nature of the proceedings, the numerosity of parties and complexity of issues involved, and the uncertainties of litigation, CenterPoint Energy and its subsidiaries are unable to predict the outcome or consequences of any of the foregoing matters or to estimate a range of potential losses. CenterPoint Energy and its subsidiaries have general and excess liability insurance policies that provide coverage for third party bodily injury and property damage claims. As CenterPoint Energy previously noted, given the nature of certain of the plaintiffs' allegations, insurance coverage may not be available other than for third party bodily injury and property damage claims caused by an accident, and one of CenterPoint Energy's insurers has reserved its rights with respect to coverage for plaintiffs' intentional nuisance claims as well as plaintiffs' claims in the gas market cases. CenterPoint Energy and its subsidiaries intend to continue to pursue all available insurance coverage for all of these matters.

Jefferson Parish. Several parishes and the State of Louisiana filed 42 suits under Louisiana's State and Local Coastal Resources Management Act against hundreds of oil and gas companies seeking compensatory damages for contamination and erosion of the Louisiana coastline allegedly caused by historical oil and gas operations. One of the defendants in one of the lawsuits (filed in 2013 only by the Parish of Jefferson) is Primary Fuels, Inc., a predecessor company of CenterPoint Energy, which operated in Louisiana from 1983 to 1989. All 42 suits were removed to Louisiana federal courts twice and were stayed for several years pending the district courts' consideration of various motions to remand and multiple appeals of remand orders. Recently, several cases involving other parishes that had been remanded to Louisiana state court have begun to resume proceedings in state court. However, as of December 31, 2024, the federal district court had not ruled on Jefferson Parish's motion to remand to state court the lawsuit which includes Primary Fuels among the defendants.

Because of the procedurally preliminary nature of the proceedings, lack of information about both the scope of and damages for Jefferson Parish's claim against Primary Fuels, Inc., the numerosity of parties and complexity of issues involved, and the uncertainties of litigation, CenterPoint Energy and its subsidiaries are unable to predict the outcome or consequences of this matter or to estimate a range of potential losses. CenterPoint Energy will continue to vigorously defend itself against the claims raised and pursue any and all available insurance coverage.

Environmental Matters

MGP Sites. CenterPoint Energy, CERC and their predecessors, including predecessors of Vectren, operated MGPs in the past. The costs CenterPoint Energy or CERC, as applicable, expect to incur to fulfill their respective obligations are estimated by management using assumptions based on actual costs incurred, the timing of expected future payments and inflation factors, among others. While CenterPoint Energy and CERC have recorded obligations for all costs which are probable and estimable, including amounts they are presently obligated to incur in connection with activities at these sites, it is possible that future events may require remedial activities which are not presently foreseen, and those costs may not be subject to PRP or insurance recovery.

(i) *Minnesota MGPs (CenterPoint Energy and CERC)*. With respect to certain Minnesota MGP sites, CenterPoint Energy and CERC have completed state-ordered remediation and continue state-ordered monitoring and water treatment. CenterPoint Energy and CERC recorded a liability as reflected in the table below for continued monitoring and any future remediation required by regulators in Minnesota.

(ii) *Indiana MGPs (CenterPoint Energy and CERC)*. In the Indiana Gas service territory, the existence, location and certain general characteristics of 26 gas manufacturing and storage sites have been identified for which CenterPoint Energy and CERC may have some remedial responsibility. A remedial investigation/feasibility study was completed at one of the sites under an agreed upon order between Indiana Gas and the IDEM, and a Record of Decision was issued by the IDEM in January 2000. The remaining sites have been submitted to the IDEM's VRP. CenterPoint Energy has also identified its involvement in five manufactured gas plant sites in SIGECO's service territory, all of which are currently enrolled in the IDEM's VRP. CenterPoint Energy is currently conducting some level of remedial activities, including groundwater monitoring at certain sites.

(iii) *Other MGPs (CenterPoint Energy and CERC).* In addition to the Minnesota and Indiana sites, the EPA and other regulators have investigated MGP sites that were owned or operated by CenterPoint Energy or CERC or may have been owned by one of their former affiliates.

Total costs that may be incurred in connection with addressing these sites cannot be determined at this time. The estimated accrued costs are limited to CenterPoint Energy's and CERC's share of the remediation efforts and are therefore net of exposures of other PRPs. The estimated range of possible remediation costs for the sites for which CenterPoint Energy and CERC believe they may have responsibility was based on remediation continuing for the minimum time frame given in the table below:

	December 31, 2024	
	CenterPoint Energy	CERC
	(in millions, except years)	
Amount accrued for remediation	$ 13	$ 11
Minimum estimated remediation costs	8	7
Maximum estimated remediation costs	47	40
Minimum years of remediation	5	5
Maximum years of remediation	50	50

The cost estimates are based on studies of a site or industry average costs for remediation of sites of similar size. The actual remediation costs will depend on the number of sites to be remediated, the participation of other PRPs, if any, and the remediation methods used.

CenterPoint Energy and CERC do not expect the ultimate outcome of these matters to have a material adverse effect on the financial condition, results of operations or cash flows of either CenterPoint Energy or CERC.

Asbestos. Some facilities owned by the Registrants or their predecessors contain or have contained asbestos insulation and other asbestos-containing materials. The Registrants are from time to time named, along with numerous others, as defendants in lawsuits filed by a number of individuals who claim injury due to exposure to asbestos, and the Registrants anticipate that additional claims may be asserted in the future. Although their ultimate outcome cannot be predicted at this time, the Registrants do not expect these matters, either individually or in the aggregate, to have a material adverse effect on their financial condition, results of operations or cash flows.

CCR Rule (CenterPoint Energy). In April 2015, the EPA finalized its CCR Rule, which regulates ash as non-hazardous material under the RCRA. The final rule allows beneficial reuse of ash, and a portion of the ash generated by Indiana Electric's generating plants will continue to be reused.

Indiana Electric has three ash ponds, two at the F.B. Culley facility (Culley East and Culley West) and one at the A.B. Brown facility. Under the CCR Rule, Indiana Electric is required to perform integrity assessments, including ground water monitoring, at its F.B. Culley and A.B. Brown generating stations. Pursuant to the CCR Rule, both the Culley East and A.B. Brown facilities were taken out of service in a timely manner per the commitments made to the EPA in the extension requests filed for both ponds. On April 24, 2019, Indiana Electric received an order from the IURC approving recovery in rates of costs associated with the closure of the Culley West pond, which has already completed closure activities. On August 14, 2019, Indiana Electric filed its petition with the IURC for recovery of costs associated with the closure of the A.B. Brown ash pond, which would include costs associated with the excavation and recycling of ponded ash. This petition was subsequently approved by the IURC on May 13, 2020. On October 28, 2020, the IURC approved Indiana Electric's ECA proceeding, which included the initiation of recovery of the federally mandated project costs.

On November 1, 2022, Indiana Electric filed for a CPCN to recover federally mandated costs associated with closure of the Culley East Pond, its third and final ash pond. Indiana Electric sought accounting and ratemaking relief for the project, and on June 8, 2023, Indiana Electric filed a revised CPCN for recovery of the federally mandated ash pond costs. On February 7, 2024 the IURC approved the federally mandated costs, both incurred and projected, of $52 million in capital costs, plus an estimated $133,000 in annual operation and maintenance expenses, for recovery through the ECA.

As of December 31, 2024, CenterPoint Energy had recorded an approximate $121 million ARO, which represents the discounted value of future cash flow estimates to close the ponds at A.B. Brown and F.B. Culley. This estimate is subject to change due to the contractual arrangements; continued assessments of the ash, closure methods, and the timing of closure; implications of Indiana Electric's generation transition plan; changing environmental regulations; and proceeds received from the settlements in a previously settled insurance proceeding. In addition to these AROs, Indiana Electric also anticipates equipment purchases of between $60 million and $80 million to complete the A.B. Brown closure project.

On April 25, 2024, the EPA released its final Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals from Electric Utilities; Legacy CCR Surface Impoundments rule (CCR Legacy Rule), which was published in the federal register in May 2024. The CCR Legacy Rule requires companies to investigate previously closed impoundments that were used historically for ash disposal or locations which have had ash placed on them in amounts set forth in the CCR Legacy Rule. The Registrants have completed their preliminary review of potential sites that will require further investigation under the CCR Legacy Rule and identified certain sites in Indiana for further evaluation. During 2024, Indiana Electric recorded an approximate $11 million ARO with a corresponding increase of $11 million to Property, plant and equipment for amounts recoverable for electric generation stations that are currently in service. These estimates reflect the discounted value of future estimated capping costs for an area of historic ash placement at F.B. Culley. Indiana Electric will continue to refine the assumptions, engineering analyses and resulting cost estimates associated with this ARO and such refinement could materially impact the amount of the estimated ARO.

Clean Water Act Permitting of Groundwater and Power Plant Discharges. In April 2020, the U.S. Supreme Court issued an opinion providing that indirect discharges via groundwater or other non-point sources are subject to permitting and liability under the Clean Water Act when they are the functional equivalent of a direct discharge. On November 27, 2023, the EPA published draft guidance regarding the application of the "functional equivalent" analysis as related to permitting of certain

discharges through groundwater to surface waters. The Registrants do not currently anticipate impacts from this guidance, but groundwater monitoring continues under the CCR Rule.

In 2015, the EPA finalized revisions to the existing steam electric wastewater discharge standards which set more stringent wastewater discharge limits and effectively prohibited further wet disposal of coal ash in ash ponds. In February 2019, the IURC approved Indiana Electric's Effluent Limitation Guidelines Compliance Plan for its F.B. Culley Generating Station, which was completed in compliance with the requirements of the Effluent Limitation Guidelines. On April 25, 2024, the EPA released its final Supplemental Effluent Limitation Guidelines and Standards for the Steam Electric Generating Point Source Category. The Registrants currently anticipate that they will be in compliance with the Supplemental ELG Guidelines at the Culley facility due to previous wastewater treatment upgrades.

Other Environmental. From time to time, the Registrants identify the presence of environmental contaminants during operations or on property where their predecessors have conducted operations. Other such sites involving contaminants may be identified in the future. The Registrants have and expect to continue to remediate any identified sites consistent with state and federal legal obligations. From time to time, the Registrants have received notices, and may receive notices in the future, from regulatory authorities or others regarding status as a PRP in connection with sites found to require remediation due to the presence of environmental contaminants. In addition, the Registrants have been, or may be, named from time to time as defendants in litigation related to such sites. Although the ultimate outcome of such matters cannot be predicted at this time, the Registrants do not expect these matters, either individually or in the aggregate, to have a material adverse effect on their financial condition, results of operations or cash flows.

Other Proceedings

The Registrants are involved in other legal, environmental, tax and regulatory proceedings before various courts, regulatory commissions and governmental agencies regarding matters arising in the ordinary course of business. From time to time, the Registrants are also defendants in legal proceedings with respect to claims brought by various plaintiffs against broad groups of participants in the energy industry. Some of these proceedings involve substantial amounts. The Registrants regularly analyze current information and, as necessary, provide accruals for probable and reasonably estimable liabilities on the eventual disposition of these matters. The Registrants do not expect the disposition of these matters to have a material adverse effect on the Registrants' financial condition, results of operations or cash flows.

(15) Earnings Per Share (CenterPoint Energy)

Basic earnings per common share is computed by dividing income available to common shareholders by the weighted average number of common shares outstanding during the period. Participating securities are excluded from weighted average number of common shares outstanding in the computation of basic earnings per common share. Diluted earnings per common share is computed by dividing income available to common shareholders by the weighted average number of common shares outstanding, including all potentially dilutive common shares, if the effect of such common shares is dilutive.

Diluted earnings per common share reflects the dilutive effect of potential common shares from share-based awards. The dilutive effect of restricted stock is computed using the if-converted method, which assumes conversion of the restricted stock at the beginning of the period. The dilutive effect of restricted stock is computed using the treasury stock method, as applicable, which includes the incremental shares that would be hypothetically vested in excess of the number of shares assumed to be hypothetically repurchased with the assumed proceeds.

Diluted earnings per common share will also reflect the dilutive effect of potential common shares from the conversion of the Convertible Notes. Convertible debt in which the principal amount must be settled in cash is excluded from the calculation of diluted earnings per common share. There would be no interest expense adjustment to the numerator for the cash-settled portion of the Convertible Notes because that portion will always be settled in cash. The conversion spread value in shares will be included in diluted earnings per common share using the if-converted method if the convertible debt is in the money. The denominator of diluted earnings per common share is determined by dividing the conversion spread value of the share-settled portion of the Convertible Notes as of the reporting date by the average share price over the reporting period. For the year ended December 31, 2024, the convertible debt was not in the money; therefore, no incremental shares were assumed converted or included in the diluted earnings per common share calculation below. For further details on the Convertible Notes, see Note 12.

The following table reconciles numerators and denominators of CenterPoint Energy's basic and diluted earnings per common share for the periods presented:

	Year Ended December 31,		
	2024	2023	2022
	(in millions, except per share and share amounts)		
Numerator:			
Net income	$ 1,019	$ 917	$ 1,057
Less: Preferred stock dividend requirement (Note 11)	—	50	49
Income available to common shareholders - basic and diluted	$ 1,019	$ 867	$ 1,008
Denominator:			
Weighted average common shares outstanding - basic	643,163,000	630,947,000	629,415,000
Plus: Incremental shares from assumed conversions:			
Restricted stock	974,000	2,232,000	2,931,000
Weighted average common shares outstanding - diluted	644,137,000	633,179,000	632,346,000
Earnings per Common Share:			
Basic	$ 1.58	$ 1.37	$ 1.60
Diluted	$ 1.58	$ 1.37	$ 1.59

(16) Reportable Segments

The Registrants' determination of reportable segments considers the strategic operating units under which its CODM manages sales, allocates resources and assesses performance of various products and services to wholesale or retail customers in differing regulatory environments.

As of December 31, 2024, reportable segments by Registrant and information about each Registrant's CODM were as follows:

CenterPoint Energy

- CenterPoint Energy's Electric reportable segment consisted of electric transmission and distribution services in the Texas Gulf Coast area in the ERCOT region and electric transmission and distribution services primarily to southwestern Indiana and includes power generation and wholesale power operations in the MISO region.

- CenterPoint Energy's Natural Gas reportable segment consists of (i) intrastate natural gas sales to, and natural gas transportation and distribution for residential, commercial and industrial customers in Indiana, Louisiana, Minnesota, Mississippi, Ohio and Texas; and (ii) permanent pipeline connections through interconnects with various interstate and intrastate pipeline companies through CEIP.

- CenterPoint Energy's Corporate and Other category consists of energy performance contracting and sustainable infrastructure services by Energy Systems Group through June 30, 2023, the date of the sale of Energy Systems Group, and corporate support operations that support all of CenterPoint Energy's business operations. CenterPoint Energy's Corporate and Other also includes office buildings and other real estate used for business operations.

CenterPoint Energy's CODM, the Chief Executive Officer, evaluates performance for all of its reportable segments based on segment net income. The CODM uses segment net income to allocate resources as part of the budgeting and forecasting process as well as during periodic budget-to-actual reviews.

Houston Electric

- Houston Electric's single reportable segment consisted of electric transmission services to transmission service customers in the ERCOT region and distribution service to REPs in the Texas Gulf Coast area that includes the city of Houston.

Houston Electric's CODM, the President and Chief Executive Officer, evaluates performance for its single reportable segment based on segment net income. The CODM uses segment net income to allocate resources as part of the budgeting and forecasting process as well as during periodic budget-to-actual reviews.

CERC

- CERC's single reportable segment following the Restructuring consisted of (i) intrastate natural gas sales to, and natural gas transportation and distribution for residential, commercial and industrial customers in Indiana, Louisiana, Minnesota, Mississippi, Ohio and Texas; and (ii) permanent pipeline connections through interconnects with various interstate and intrastate pipeline companies through CEIP.

CERC's CODM, the President and Chief Executive Officer, evaluates performance for its single reportable segment based on segment net income. The CODM uses segment net income to allocate resources as part of the budgeting and forecasting process as well as during periodic budget-to-actual reviews.

Expenditures for long-lived assets include property, plant and equipment. Intersegment sales are eliminated in consolidation, except as described in Note 4.

Financial data for reportable segments is as follows:

CenterPoint Energy

	Year Ended December 31, 2024					
	Electric	Natural Gas	Corporate and Other	Total Reportable Segments	Eliminations	Total
	(in millions)					
Revenues from external customers	$ 4,590	$ 4,048	$ 5	$ 8,643	$ —	$ 8,643
Intersegment revenues	—	2	—	2	(2)	—
Utility natural gas, fuel and purchased power	198	1,520	(1)	1,717	(2)	1,715
Non-utility cost of revenues, including natural gas	—	3	—	3	—	3
Operation and maintenance expenses	2,072	881	(4)	2,949	—	2,949
Depreciation and amortization	877	542	20	1,439	—	1,439
Taxes other than income taxes	304	237	6	547	—	547
Interest expense	372	207	286	865	(27)	838
Income tax expense (benefit)	157	108	(70)	195	—	195
Interest income (1)	(18)	(2)	(14)	(34)	27	(7)
Other income, net (2)	(43)	(12)	—	(55)	—	(55)
Net income (loss)	$ 671	$ 566	$ (218)	$ 1,019	$ —	$ 1,019

	Year Ended December 31, 2023					
	Electric	Natural Gas	Corporate and Other	Total Reportable Segments	Eliminations	Total
	(in millions)					
Revenues from external customers	$ 4,290	$ 4,276	$ 130	$ 8,696	$ —	$ 8,696
Intersegment revenues	—	3	—	3	(3)	—
Utility natural gas, fuel and purchased power	176	1,888	—	2,064	(3)	2,061
Non-utility cost of revenues, including natural gas	—	3	96	99	—	99
Operation and maintenance expenses	1,880	949	21	2,850	—	2,850
Depreciation and amortization	872	513	16	1,401	—	1,401
Taxes other than income taxes	272	245	8	525	—	525
Interest expense	303	188	264	755	(54)	701
Income tax expense (benefit)	189	(25)	6	170	—	170
Interest income (1)	(19)	(10)	(34)	(63)	54	(9)
Other expense (income), net (2)	(37)	(5)	23	(19)	—	(19)
Net income (loss)	$ 654	$ 533	$ (270)	$ 917	$ —	$ 917

	Year Ended December 31, 2022					
	Electric	Natural Gas	Corporate and Other	Total Reportable Segments	Eliminations	Total
	(in millions)					
Revenues from external customers	$ 4,108	$ 4,946	$ 267	$ 9,321	$ —	$ 9,321
Utility natural gas, fuel and purchased power	222	2,665	—	2,887	—	2,887
Non-utility cost of revenues, including natural gas	—	4	200	204	—	204
Operation and maintenance expenses	1,864	919	50	2,833	—	2,833
Depreciation and amortization	793	466	29	1,288	—	1,288
Taxes other than income taxes	275	261	7	543	—	543
Interest expense	235	137	214	586	(62)	524
Income tax expense (benefit)	147	243	(30)	360	—	360
Interest income (1)	(4)	(2)	(60)	(66)	62	(4)
Other income, net (2)	(27)	(239)	(105)	(371)	—	(371)
Net income (loss)	$ 603	$ 492	$ (38)	$ 1,057	$ —	$ 1,057

(1) Interest income from Securitization Bonds of $3 million, $4 million, and less than $1 million for the years ended December 31, 2024, 2023 and 2022, respectively, is included in Other income (expense), net on CenterPoint Energy's Statements of Consolidated Income.

(2) Other income (expense), net primarily includes AFUDC equity, non-service cost for pension and postretirement benefits, Gain (loss) on equity securities, Gain (loss) on indexed debt securities and Gain (loss) on sale.

	Total Assets		Expenditures for Long-lived Assets		
	As of December 31,		Year Ended December 31,		
	2024	2023	2024	2023	2022
			(in millions)		
Electric	$ 23,936	$ 21,089	$ 3,099	$ 2,660	$ 2,611
Natural Gas	18,583	17,429	1,524	1,697	1,697
Corporate and Other, net of eliminations (1)	1,249	1,197	26	13	107
Continuing Operations	43,768	39,715	4,649	4,370	4,415
Divestitures (2)	—	—	—	—	3
Consolidated	$ 43,768	$ 39,715	$ 4,649	$ 4,370	$ 4,418

(1) Total assets included pension and other postemployment-related regulatory assets of $384 million and $385 million as of December 31, 2024 and 2023, respectively.
(2) For further information regarding CenterPoint Energy's and CERC's divestitures, see Note 4.

Houston Electric

Houston Electric consists of a single reportable segment. For financial data related to income and expenses for the single reportable segment, see Houston Electric's Statements of Consolidated Income. For financial data related to segment total assets, see Houston Electric's Consolidated Balance Sheets. Financial data related to interest income and expenditures for long-lived assets is as follows:

	Year Ended December 31,		
	2024	2023	2022
	(in millions)		
Interest income (1)	$ 16	$ 14	$ 3
Expenditures for long-lived assets	2,738	2,309	2,302

(1) Reflected in Other income (expense), net on Houston Electric's Statements of Consolidated Income.

CERC

CERC consists of a single reportable segment. For financial data related to income and expenses for the single reportable segment, see CERC's Statements of Consolidated Income. For financial data related to segment total assets, see CERC's Consolidated Balance Sheets. Financial data related to interest income and expenditures for long-lived assets is as follows:

	Year Ended December 31,		
	2024	2023	2022
	(in millions)		
Interest income (1)	$ 2	$ 10	$ 3
Expenditures for long-lived assets	1,485	1,568	1,616

(1) Reflected in Other income (expense), net on CERC's Statements of Consolidated Income.

Major Customers (Houston Electric)

Houston Electric's revenues from major external customers are as follows:

	Year Ended December 31,		
	2024	2023	2022
	(in millions)		
Affiliates of NRG	$ 1,169	$ 1,106	$ 1,046
Affiliates of Vistra Energy Corp.	605	539	489

Revenues by Products and Services

	Year Ended December 31,								
	2024			2023			2022		
	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC
	(in millions)								
Electric delivery	$ 3,963	$ 3,939	$ —	$ 3,701	$ 3,677	$ —	$ 3,438	$ 3,412	$ —
Retail electric sales	622	—	—	569	—	—	630	—	—
Wholesale electric sales	4	—	—	20	—	—	40	—	—
Retail gas sales	3,837	—	3,716	4,078	—	3,951	4,759	—	4,613
Gas transportation	11	—	11	11	—	11	12	—	12
Energy products and services	206	—	198	317	—	187	442	—	175
Total	$ 8,643	$ 3,939	$ 3,925	$ 8,696	$ 3,677	$ 4,149	$ 9,321	$ 3,412	$ 4,800

(17) Supplemental Disclosure of Cash Flow and Balance Sheet Information

Supplemental Disclosure of Cash Flow Information

The tables below provide supplemental disclosure of cash flow information for the periods presented:

	2024			2023			2022		
	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC
	(in millions)								
Cash Payments (Refunds):									
Interest, net of capitalized interest	$ 805	$ 321	$ 190	$ 664	$ 287	$ 175	$ 480	$ 223	$ 104
Income tax payments (refunds), net (1)	(9)	26	3	215	12	115	421	142	37
Non-cash transactions:									
Accounts payable related to capital expenditures	467	381	103	246	166	74	335	168	139
ROU assets obtained in exchange for lease liabilities (2)	18	—	13	3	1	—	7	6	—

(1) CenterPoint Energy's $215 million income tax payments in 2023 were attributable to recovery of extraordinary gas costs incurred in the February 2021 Winter Storm through the Railroad Commission ordered securitization.

(2) Excludes ROU assets obtained through prepayment of the lease liabilities. See Note 19.

The table below provides a reconciliation of cash, cash equivalents and restricted cash reported in the Consolidated Balance Sheets to the amount reported in the Statements of Consolidated Cash Flows for the periods presented:

	December 31, 2024			December 31, 2023		
	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC
	(in millions)					
Cash and cash equivalents (1)	$ 24	$ 14	$ 2	$ 90	$ 76	$ 1
Restricted cash included in Prepaid expenses and other current assets (2)	6	—	—	19	13	—
Total cash, cash equivalents and restricted cash shown in Statements of Consolidated Cash Flows	$ 30	$ 14	$ 2	$ 109	$ 89	$ 1

(1) Cash and cash equivalents related to VIEs as of December 31, 2024 and 2023 included $21 million and $90 million, respectively, at CenterPoint Energy and $14 million and $76 million, respectively, at Houston Electric.

(2) Restricted cash primarily related to accounts established by CenterPoint Energy and Houston Electric in connection with the issuance of the Securitization Bonds to collateralize the Securitization Bonds that were issued in these financing transactions. These restricted cash accounts are not available for withdrawal until the maturity of the Securitization Bonds.

Supplemental Disclosure of Balance Sheet Information

Included in other current liabilities on CERC's Consolidated Balance Sheets as of December 31, 2024 and 2023 was $98 million and $118 million, respectively, of credits related to customers on budget billing programs. Included in other current liabilities on Houston Electric's Consolidated Balance Sheets as of December 31, 2024 and 2023 was $85 million and $47 million, respectively, of builder deposits.

(18) Related Party Transactions (Houston Electric and CERC)

Houston Electric and CERC participate in CenterPoint Energy's money pool through which they can borrow or invest on a short-term basis. Funding needs are aggregated and external borrowing or investing is based on the net cash position. The net funding requirements of the CenterPoint Energy money pool are expected to be met with borrowings under CenterPoint Energy's revolving credit facility or the sale of CenterPoint Energy's commercial paper.

The table below summarizes CenterPoint Energy money pool activity for the periods presented:

	December 31, 2024		December 31, 2023	
	Houston Electric	CERC	Houston Electric	CERC
	(in millions, except interest rates)			
Money pool investments (1)	$ 368	$ —	$ 238	$ 1
Weighted average interest rate	4.65 %	— %	5.59 %	5.59 %

(1) Included in Accounts and notes receivable–affiliated companies in Houston Electric's and CERC's respective Consolidated Balance Sheets as of December 31, 2024 and 2023, as applicable.

Houston Electric and CERC affiliate-related transactions were as follows:

	Year Ended December 31,					
	2024		2023		2022	
	Houston Electric	CERC	Houston Electric	CERC	Houston Electric	CERC (1)
	(in millions)					
Interest income (expense), net (2)	$ 9	$ 2	$ 2	$ 10	$ —	$ (18)

(1) Includes affiliate-related net interest expense of Indiana Gas and CEOH to reflect the Restructuring.
(2) Interest income is included in Other, net and interest expense is included in Interest expense and other finance charges on Houston Electric's and CERC's respective Statements of Consolidated Income.

CenterPoint Energy provides some corporate services to Houston Electric and CERC. The costs of services have been charged directly to Houston Electric and CERC using methods that management believes are reasonable. These methods include usage rates, dedicated asset assignment and proportionate corporate formulas based on operating expenses, assets, gross margin, employees and a composite of assets, gross margin and employees. Houston Electric provides certain services to CERC. These services are billed at actual cost, either directly or as an allocation and include fleet services, shop services, geographic services, surveying and right-of-way services, radio communications, data circuit management and field operations. Additionally, CERC provides certain services to Houston Electric. These services are billed at actual cost, either directly or as an allocation and include line locating and other miscellaneous services. These charges are not necessarily indicative of what would have been incurred had Houston Electric and CERC not been affiliates.

The table below presents amounts charged for these services, which are included primarily in Operation and maintenance expenses on Houston Electric's and CERC's respective Statements of Consolidated Income, for the periods presented:

	Year Ended December 31,					
	2024		2023		2022	
	Houston Electric	CERC	Houston Electric	CERC	Houston Electric	CERC
	(in millions)					
Corporate service charges	$ 173	$ 213	$ 173	$ 236	$ 167	$ 237
Net affiliate service charges (billings)	(5)	5	(10)	10	15	(15)

The table below presents transactions among Houston Electric, CERC and their parent, Utility Holding, for the periods presented:

	Year Ended December 31,					
	2024		2023		2022	
	Houston Electric	CERC	Houston Electric	CERC	Houston Electric	CERC
	(in millions)					
Cash dividends paid to parent	$ 339	$ 442	$ 367	$ 496	$ 316	$ 124
Cash dividend paid to parent related to the sale of the Arkansas and Oklahoma Natural Gas businesses	—	—	—	—	—	720
Cash contribution from parent	844	290	885	500	1,143	289
Net assets acquired in the Restructuring (1)	—	—	—	—	—	2,345
Non-cash capital contribution from parent in payment for property, plant and equipment below	—	—	—	—	38	54
Cash paid to parent for property, plant and equipment below	—	—	—	—	65	61
Property, plant and equipment from parent (2)	—	—	—	—	103	115

(1) The Restructuring was a common control transaction that required the recasting of financial information to the earliest period presented. Therefore, the net asset transfer was not reflected during the year ended December 31, 2022 on CERC's Statements of Consolidated Changes in Equity.
(2) Property, plant and equipment purchased from CenterPoint Energy at its net carrying value on the date of purchase.

(19) Leases

In 2021, Houston Electric entered into a temporary short-term lease and long-term leases for temporary generation. The short-term lease agreement expired on December 31, 2022. Effective January 1, 2023, all temporary generation assets were leased under the long-term lease agreement. Expenses associated with the short-term lease, including carrying costs, are deferred to a regulatory asset and totaled $89 million and $100 million as of December 31, 2024 and 2023, respectively.

The long-term lease agreement includes up to 505 MW of TEEEF, all of which was delivered as of December 31, 2022, triggering lease commencement at delivery, with an initial term ending in 2029 for all TEEEF leases. The total cash payments under the long-term lease totaled $664 million, with the final $485 million paid in 2022. Houston Electric derecognized the finance lease liability when the extinguishment criteria in Topic 405 - *Liabilities* was achieved. Per the terms of the agreement, lease payments are due and made in full by Houston Electric upon taking possession of the asset, relieving substantially all of the associated finance lease liability at that time. The remaining finance lease liability associated with the commenced long-term TEEEF agreement was not significant as of December 31, 2024 and 2023 and relates to removal costs that will be incurred at the end of the lease term. As of December 31, 2024, Houston Electric had secured a first lien on the assets leased under the prepayment agreement, except for assets with lease payments totaling $79 million, which is being held in an escrow account, not controlled by Houston Electric, and the funds will be released when a first lien can be secured by Houston Electric. Expenses associated with the long-term lease, including variable costs associated with the operation and maintenance of the temporary generation assets, depreciation expense on the right of use asset and carrying costs, are deferred to a regulatory asset as a recoverable cost under the 2021 Texas legislation and totaled $158 million and $124 million as of December 31, 2024 and 2023, respectively. For further discussion of the regulatory impacts, see Note 7.

The components of lease cost, included in Operation and maintenance expense on the Registrants' respective Statements of Consolidated Income, are as follows for the periods presented:

	Year Ended December 31,								
	2024			2023			2022		
	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC
	(in millions)								
Operating lease cost	$ 6	$ 3	$ 2	$ 6	$ 3	$ 2	$ 6	$ 1	$ 2
Short-term lease cost	12	11	—	31	30	—	167	166	1
Total lease cost (1)	$ 18	$ 14	$ 2	$ 37	$ 33	$ 2	$ 173	$ 167	$ 3

(1) CenterPoint Energy and Houston Electric defer finance lease costs for TEEEF to Regulatory assets for recovery rather than to Depreciation and Amortization in the Statements of Consolidated Income.

The components of lease income were as follows for the periods presented:

	Year Ended December 31,								
	2024			2023			2022		
	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC
	(in millions)								
Operating lease income	$ 7	$ —	$ 5	$ 6	$ 1	$ 4	$ 5	$ 1	$ 3
Variable lease income	1	—	—	2	—	—	2	—	—
Total lease income	$ 8	$ —	$ 5	$ 8	$ 1	$ 4	$ 7	$ 1	$ 3

Supplemental balance sheet information related to leases was as follows for the periods presented:

	December 31, 2024			December 31, 2023		
	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC
	(in millions)					
Assets:						
Operating ROU assets (1)	$ 27	$ 5	$ 15	$ 13	$ 6	$ 4
Finance ROU assets (2)	430	430	—	526	526	—
Total leased assets	$ 457	$ 435	$ 15	$ 539	$ 532	$ 4
Liabilities:						
Current operating lease liability (3)	$ 3	$ 1	$ 1	$ 3	$ 1	$ 1
Non-current operating lease liability (4)	25	3	14	10	5	3
Total leased liabilities (5)	$ 28	$ 4	$ 15	$ 13	$ 6	$ 4

(1) Included in Other assets in the Registrants' respective Consolidated Balance Sheets, net of accumulated amortization.
(2) Included in Property, Plant and Equipment in the Registrants' respective Consolidated Balance Sheets, net of accumulated amortization.
(3) Included in Current other liabilities in the Registrants' respective Consolidated Balance Sheets.
(4) Included in Other non-current liabilities in the Registrants' respective Consolidated Balance Sheets.
(5) Finance lease liabilities were not material as of December 31, 2024 or 2023.

As of December 31, 2024 and 2023, the weighted-average remaining lease term and weighted-average discount rate for the Registrants' finance and operating leases were as follows:

	December 31, 2024			December 31, 2023		
	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC
Weighted-average remaining lease term (in years) - operating leases	17.7	2.9	20.6	4.7	3.9	3.1
Weighted-average discount rate - operating leases	4.92 %	4.11 %	5.03 %	4.13 %	4.09 %	3.60 %
Weighted-average remaining lease term (in years) - finance leases	4.5	4.5	—	5.5	5.5	—
Weighted-average discount rate - finance leases	3.60 %	3.60 %	—	3.60 %	3.60 %	—

As of December 31, 2024, finance lease liabilities were not significant to the Registrants. As of December 31, 2024, maturities of operating lease liabilities were as follows:

	CenterPoint Energy	Houston Electric	CERC
		(in millions)	
2025	$ 4	$ 2	$ 2
2026	4	1	2
2027	3	1	1
2028	2	—	1
2029	2	—	1
Thereafter	30	—	19
Total lease payments	45	4	26
Less: Interest	17	—	11
Present value of lease liabilities	$ 28	$ 4	$ 15

As of December 31, 2024, future minimum finance lease payments to be received were not significant to the Registrants. As of December 31, 2024, maturities of undiscounted operating lease payments to be received were as follows:

	CenterPoint Energy	Houston Electric	CERC
		(in millions)	
2025	$ 9	$ 1	$ 6
2026	9	—	6
2027	8	—	7
2028	4	—	2
2029	1	—	—
Thereafter	1	—	—
Total lease payments to be received	$ 32	$ 1	$ 21

Other information related to leases is as follows for the periods presented:

	Year Ended December 31,								
	2024			2023			2022		
	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC	CenterPoint Energy	Houston Electric	CERC
					(in millions)				
Operating cash flows from operating leases included in the measurement of lease liabilities	$ 5	$ 2	$ 2	$ 5	$ 2	$ 2	$ 6	$ 1	$ 2
Financing cash flows from finance leases included in the measurement of lease liabilities	—	—	—	—	—	—	485	485	—

See Note 17 for information on ROU assets obtained in exchange for operating lease liabilities.

(20) Subsequent Events

Credit Facilities

On January 29, 2025, CenterPoint Energy, Houston Electric, CERC and SIGECO each entered into Extension Agreements to, among other things, extend the maturity date of the lenders' commitments under each of their respective Credit Agreements by one year, from December 6, 2027 to December 6, 2028.

SIGECO First Mortgage Bonds (CenterPoint Energy)

On January 31, 2025, SIGECO issued $165 million aggregate principal amount of 5.69% First Mortgage Bonds, Series 2025A, Tranche A due 2055. Total net proceeds from SIGECO's January 2025 issuance of first mortgage bonds, net of transaction expenses and fees, were approximately $164 million, which will be used for the acquisition of Posey Solar.

Item 9. ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure***

None.

Item 9A. ***Controls and Procedures***

Disclosure Controls And Procedures

In accordance with Exchange Act Rules 13a-15 and 15d-15, the Registrants carried out separate evaluations, under the supervision and with the participation of each company's management, including the principal executive officer and principal financial officer, of the effectiveness of the disclosure controls and procedures as of the end of the period covered by this report. Based on those evaluations, the principal executive officer and principal financial officer, in each case, concluded that the disclosure controls and procedures were effective as of December 31, 2024 to provide assurance that information required to be disclosed in the reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms and such information is accumulated and communicated to management, including the principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding disclosure.

Changes in Internal Control Over Financial Reporting

There has been no change in the Registrants' internal controls over financial reporting that occurred during the three months ended December 31, 2024 that has materially affected, or is reasonably likely to materially affect, the Registrants' internal controls over financial reporting.

Management's Annual Report on Internal Control over Financial Reporting

The Registrants' management is responsible for establishing and maintaining adequate internal control over financial reporting. Internal control over financial reporting is defined in Rule 13a-15(f) or 15d-15(f) promulgated under the Securities Exchange Act of 1934 as a process designed by, or under the supervision of, the Registrants' principal executive and principal financial officers and effected by CenterPoint Energy's board of directors, management and other personnel, 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 and includes those policies and procedures that:

- Pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of the assets of the Registrants;

- Provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the Registrants are being made only in accordance with authorizations of management and directors of the Registrants; and

- Provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the Registrants' assets that could have a material effect on the financial statements.

Management has designed its internal control over financial reporting to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements in accordance with accounting principles generally accepted in the United States of America. Management's assessment included review and testing of both the design effectiveness and operating effectiveness of controls over all relevant assertions related to all significant accounts and disclosures in the financial statements.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Under the supervision and with the participation of the Registrants' management, including their respective principal executive officers and principal financial officers, the Registrants conducted an evaluation of the effectiveness of their internal control over financial reporting based on the framework in *Internal Control — Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the Registrants' evaluation under the framework in *Internal Control — Integrated Framework* (2013), the Registrants' management has concluded, in each case, that their internal control over financial reporting was effective as of December 31, 2024.

Deloitte & Touche LLP, CenterPoint Energy's independent registered public accounting firm, has issued an attestation report on the effectiveness of CenterPoint Energy's internal control over financial reporting as of December 31, 2024 which is set forth below. This report is not applicable to Houston Electric or CERC as they are not accelerated or large accelerated filers.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and the Board of Directors of
CenterPoint Energy, Inc.

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of CenterPoint Energy, Inc. and subsidiaries (the "Company") as of December 31, 2024, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2024, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements as of and for the year ended December 31, 2024, of the Company and our report dated February 20, 2025, expressed an unqualified opinion on those financial statements.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed 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. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
February 20, 2025

Item 9B. ***Other Information***

None.

Rule 10b5-1 Trading Arrangements

During the three months ended December 31, 2024, no director or officer of CenterPoint Energy, Houston Electric or CERC adopted or terminated a "Rule 10b5-1 trading arrangement" or "non-Rule 10b5-1 trading arrangement," as each term is defined in Item 408 of Regulation S-K.

Item 9C. ***Disclosure Regarding Foreign Jurisdictions that Prevent Inspections***

Not Applicable.

PART III

Item 10. ***Directors, Executive Officers and Corporate Governance***

For CenterPoint Energy, the information called for by Item 10, to the extent not set forth in "Information About Our Executive Officers" in Item 1 of Part I of this report, will be set forth in the definitive proxy statement relating to CenterPoint Energy's 2025 annual meeting of shareholders pursuant to SEC Regulation 14A. Such definitive proxy statement relates to a meeting of shareholders involving the election of directors and the portions thereof called for by Item 10 are incorporated herein by reference pursuant to Instruction G to Form 10-K.

For Houston Electric and CERC, the information called for by Item 10 is omitted pursuant to Instruction I(2) to Form 10-K (Omission of Information by Certain Wholly-Owned Subsidiaries).

Item 11. ***Executive Compensation***

For CenterPoint Energy, the information called for by Item 11 will be set forth in the definitive proxy statement relating to CenterPoint Energy's 2025 annual meeting of shareholders pursuant to SEC Regulation 14A. Such definitive proxy statement relates to a meeting of shareholders involving the election of directors and the portions thereof called for by Item 11 are incorporated herein by reference pursuant to Instruction G to Form 10-K.

For Houston Electric and CERC, the information called for by Item 11 is omitted pursuant to Instruction I(2) to Form 10-K (Omission of Information by Certain Wholly-Owned Subsidiaries).

Item 12. ***Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters***

For CenterPoint Energy, the information called for by Item 12 will be set forth in the definitive proxy statement relating to CenterPoint Energy's 2025 annual meeting of shareholders pursuant to SEC Regulation 14A. Such definitive proxy statement relates to a meeting of shareholders involving the election of directors and the portions thereof called for by Item 12 are incorporated herein by reference pursuant to Instruction G to Form 10-K.

For Houston Electric and CERC, the information called for by Item 12 is omitted pursuant to Instruction I(2) to Form 10-K (Omission of Information by Certain Wholly-Owned Subsidiaries).

Item 13. ***Certain Relationships and Related Transactions, and Director Independence***

For CenterPoint Energy, the information called for by Item 13 will be set forth in the definitive proxy statement relating to CenterPoint Energy's 2025 annual meeting of shareholders pursuant to SEC Regulation 14A. Such definitive proxy statement relates to a meeting of shareholders involving the election of directors and the portions thereof called for by Item 13 are incorporated herein by reference pursuant to Instruction G to Form 10-K.

For Houston Electric and CERC, the information called for by Item 13 is omitted pursuant to Instruction I(2) to Form 10-K (Omission of Information by Certain Wholly-Owned Subsidiaries).

Item 14. ***Principal Accounting Fees and Services***

For CenterPoint Energy, the information called for by Item 14 will be set forth in the definitive proxy statement relating to CenterPoint Energy's 2025 annual meeting of shareholders pursuant to SEC Regulation 14A. Such definitive proxy statement relates to a meeting of shareholders involving the election of directors and the portions thereof called for by Item 14 are incorporated herein by reference pursuant to Instruction G to Form 10-K.

Aggregate fees billed to Houston Electric and CERC during the years ended December 31, 2024 and 2023 by their principal accounting firm, Deloitte & Touche LLP, are set forth below.

	Year Ended December 31,			
	2024		2023	
	Houston Electric	CERC	Houston Electric	CERC
Audit fees (1)	$ 948,480	$ 1,337,600	$ 843,661	$ 1,155,700
Audit-related fees (2)	1,088,145	449,000	530,000	410,000
Total audit and audit-related fees	2,036,625	1,786,600	1,373,661	1,565,700
Tax fees	—	—	—	—
All other fees	—	—	—	—
Total fees	$ 2,036,625	$ 1,786,600	$ 1,373,661	$ 1,565,700

(1) For 2024 and 2023, amounts include fees for services provided by the principal accounting firm relating to the integrated audit of financial statements and internal control over financial reporting, statutory audits, attest services, and regulatory filings.

(2) For 2024 and 2023, amounts include fees for consultations concerning financial accounting and reporting standards and various agreed-upon or expanded procedures related to accounting records to comply with financial accounting or regulatory reporting matters.

Houston Electric and CERC each are not required to have, and do not have, an audit committee.

PART IV

Item 15. ***Exhibits and Financial Statement Schedules***

(a)(1) Financial Statements.

CenterPoint Energy	
Report of Independent Registered Public Accounting Firm (PCAOB ID No. 34)	93
Statements of Consolidated Income for the Three Years Ended December 31, 2024	95
Statements of Consolidated Comprehensive Income for the Three Years Ended December 31, 2024	96
Consolidated Balance Sheets as of December 31, 2024 and 2023	97
Statements of Consolidated Cash Flows for the Three Years Ended December 31, 2024	99
Statements of Consolidated Changes in Equity for the Three Years Ended December 31, 2024	100
Houston Electric	
Report of Independent Registered Public Accounting Firm (PCAOB ID No. 34)	101
Statements of Consolidated Income for the Three Years Ended December 31, 2024	103
Statements of Consolidated Comprehensive Income for the Three Years Ended December 31, 2024	104
Consolidated Balance Sheets as of December 31, 2024 and 2023	105
Statements of Consolidated Cash Flows for the Three Years Ended December 31, 2024	107
Statements of Consolidated Changes in Equity for the Three Years Ended December 31, 2024	108
CERC	
Report of Independent Registered Public Accounting Firm (PCAOB ID No. 34)	109
Statements of Consolidated Income for the Three Years Ended December 31, 2024	111
Statements of Consolidated Comprehensive Income for the Three Years Ended December 31, 2024	112
Consolidated Balance Sheets as of December 31, 2024 and 2023	113
Statements of Consolidated Cash Flows for the Three Years Ended December 31, 2024	115
Statements of Consolidated Changes in Equity for the Three Years Ended December 31, 2024	116
Combined Notes to Consolidated Financial Statements	117

(a)(2) Financial Statement Schedules for the Three Years Ended December 31, 2024

The following schedules are omitted by the Registrants because of the absence of the conditions under which they are required or because the required information is included in the financial statements:

I, II, III, IV and V.

(a)(3) Exhibits.

See Index of Exhibits beginning on page 187, which index also includes the management contracts or compensatory plans or arrangements required to be filed as exhibits to this Form 10-K by Item 601(b)(10)(iii) of Regulation S-K.

Item 16. ***Form 10-K Summary***

None.

CENTERPOINT ENERGY, INC. AND SUBSIDIARIES
CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC AND SUBSIDIARIES
CENTERPOINT ENERGY RESOURCES CORP. AND SUBSIDIARIES

EXHIBITS TO THE COMBINED ANNUAL REPORT ON FORM 10-K
For Fiscal Year Ended December 31, 2024

INDEX OF EXHIBITS

Exhibits included with this report are designated by a cross (†); all exhibits not so designated are incorporated herein by reference to a prior filing as indicated. Exhibits designated by an asterisk (*) are management contracts or compensatory plans or arrangements required to be filed as exhibits to this Form 10-K by Item 601(b)(10)(iii) of Regulation S-K. The Registrants have not filed the exhibits and schedules to Exhibit 2. The Registrants hereby agree to furnish supplementally a copy of any schedule omitted from Exhibit 2 to the SEC upon request.

The agreements included as exhibits are included only to provide information to investors regarding their terms. The agreements listed below may contain representations, warranties and other provisions that were made, among other things, to provide the parties thereto with specified rights and obligations and to allocate risk among them, and such agreements should not be relied upon as constituting or providing any factual disclosures about us, any other persons, any state of affairs or other matters.

Exhibit Number		Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference	CenterPoint Energy	Houston Electric	CERC
2(a)	—	Asset Purchase Agreement by and between CenterPoint Energy Resources Corp. and Southern Col Midco, LLC, dated as of April 29, 2021	CenterPoint Energy's Form 10-Q for the quarter ended March 31, 2021	1-31447	2.4	X		X
2(b)	—	Asset Purchase Agreement, dated February 19, 2024, among CenterPoint Energy Resources Corp. and Delta Utilities No. LA, LLC, Delta Utilities S. LA, LLC, Delta Utilities MS, LLC, and Delta Shared Services Co., LLC	CenterPoint Energy's Form 8-K dated February 19, 2024	1-31447	1.1	X		X
3(a)	—	Restated Articles of Incorporation of CenterPoint Energy	CenterPoint Energy's Form 8-K dated July 24, 2008	1-31447	3.2	X		
3(b)	—	Restated Certificate of Formation of Houston Electric	Houston Electric's Form 10-Q for the quarter ended June 30, 2011	1-3187	3.1		X	
3(c)	—	Certificate of Incorporation of RERC Corp.	CERC Form 10-K for the year ended December 31, 1997	1-13265	3(a)(1)			X
3(d)	—	Certificate of Amendment changing the name to Reliant Energy Resources Corp.	CERC Form 10-K for the year ended December 31, 1998	1-13265	3(a)(3)			X
3(e)	—	Certificate of Amendment changing the name to CenterPoint Energy Resources Corp.	CERC Form 10-Q for the quarter ended June 30, 2003	1-13265	3(a)(4)			X
3(f)	—	Fourth Amended and Restated Bylaws of CenterPoint Energy	CenterPoint Energy's Form 10-K for the year ended December 31, 2023	1-31447	3(h)	X		

Exhibit Number		Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference	CenterPoint Energy	Houston Electric	CERC
3(g)	—	Amended and Restated Limited Liability Company Agreement of Houston Electric	Houston Electric's Form 10-Q for the quarter ended June 30, 2011	1-3187	3.2		X	
3(h)	—	Bylaws of RERC Corp.	CERC Form 10-K for the year ended December 31, 1997	1-13265	3(b)			X
3(i)	—	Statement of Resolutions Deleting Shares Designated Series A Preferred Stock of CenterPoint Energy	CenterPoint Energy's Form 10-K for the year ended December 31, 2011	1-31447	3(c)	X		
4(a)	—	Form of CenterPoint Energy Stock Certificate	CenterPoint Energy's Registration Statement on Form S-4	333-69502	4.1	X		
4(b)(1)	—	Mortgage and Deed of Trust, dated November 1, 1944 between Houston Lighting and Power Company (HL&P) and Chase Bank of Texas, National Association (formerly, South Texas Commercial National Bank of Houston), as Trustee, as amended and supplemented by 20 Supplemental Indentures thereto	HL&P's Form S-7 filed on August 25, 1977	2-59748	2(b)	X	X	
4(b)(2)	—	Twenty-First through Fiftieth Supplemental Indentures to Exhibit 4(b)(1)	HL&P's Form 10-K for the year ended December 31, 1989	1-3187	4(a)(2)	X	X	
4(b)(3)	—	Fifty-First Supplemental Indenture to Exhibit 4(b)(1) dated as of March 25, 1991	HL&P's Form 10-Q for the quarter ended June 30, 1991	1-3187	4(a)	X	X	
4(b)(4)	—	Fifty-Second through Fifty-Fifth Supplemental Indentures to Exhibit 4(b)(1) each dated as of March 1, 1992	HL&P's Form 10-Q for the quarter ended March 31, 1992	1-3187	4	X	X	
4(b)(5)	—	Fifty-Sixth and Fifty-Seventh Supplemental Indentures to Exhibit 4(b)(1) each dated as of October 1, 1992	HL&P's Form 10-Q for the quarter ended September 30, 1992	1-3187	4	X	X	
4(b)(6)	—	Fifty-Eighth and Fifty-Ninth Supplemental Indentures to Exhibit 4(b)(1) each dated as of March 1, 1993	HL&P's Form 10-Q for the quarter ended March 31, 1993	1-3187	4	X	X	
4(b)(7)	—	Sixtieth Supplemental Indenture to Exhibit 4(b)(1) dated as of July 1, 1993	HL&P's Form 10-Q for the quarter ended June 30, 1993	1-3187	4	X	X	
4(b)(8)	—	Sixty-First through Sixty-Third Supplemental Indentures to Exhibit 4(b)(1) each dated as of December 1, 1993	HL&P's Form 10-K for the year ended December 31, 1993	1-3187	4(a)(8)	X	X	

Exhibit Number		Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference	CenterPoint Energy	Houston Electric	CERC
4(b)(9)	—	Sixty-Fourth and Sixty-Fifth Supplemental Indentures to Exhibit 4(b)(1) each dated as of July 1, 1995	HL&P's Form 10-K for the year ended December 31, 1995	1-3187	4(a)(9)	X	X	
4(c)(1)	—	General Mortgage Indenture, dated as of October 10, 2002, between CenterPoint Energy Houston Electric, LLC and JPMorgan Chase Bank, as Trustee	Houston Electric's Form 10-Q for the quarter ended September 30, 2002	1-3187	4(j)(1)	X	X	
4(c)(2)	—	Third Supplemental Indenture to Exhibit 4(c)(1), dated as of October 10, 2002	Houston Electric's Form 10-Q for the quarter ended September 30, 2002	1-3187	4(j)(4)	X	X	
4(c)(3)	—	Officer's Certificates dated October 10, 2002 setting forth the form, terms and provisions of the First through Eighth Series of General Mortgage Bonds	CenterPoint Energy's Form 10-K for the year ended December 31, 2003	1-31447	4(e)(10)	X	X	
4(c)(4)	—	Ninth Supplemental Indenture to Exhibit 4(c)(1), dated as of November 12, 2002	CenterPoint Energy's Form 10-K for the year ended December 31, 2002	1-31447	4(e)(10)	X	X	
4(c)(5)	—	Tenth Supplemental Indenture to Exhibit 4(c)(1), dated as of March 18, 2003	CenterPoint Energy's Form 8-K dated March 13, 2003	1-31447	4.1	X	X	
4(c)(6)	—	Officer's Certificate dated March 18, 2003 setting forth the form, terms and provisions of the Tenth Series and Eleventh Series of General Mortgage Bonds	CenterPoint Energy's Form 8-K dated March 13, 2003	1-31447	4.2	X	X	
4(c)(7)	—	Twentieth Supplemental Indenture to Exhibit 4(c)(1), dated as of December 9, 2008	Houston Electric's Form 8-K dated January 6, 2009	1-3187	4.2	X	X	
4(c)(8)	—	Twenty-Second Supplemental Indenture to Exhibit 4(c)(1) dated as of August 10, 2012	CenterPoint Energy's Form 10-K for the year ended December 31, 2012	1-31447	4(e)(33)	X	X	
4(c)(9)	—	Officer's Certificate, dated August 10, 2012 setting forth the form, terms and provisions of the Twenty-Second Series of General Mortgage Bonds	CenterPoint Energy's Form 10-K for the year ended December 31, 2012	1-31447	4(e)(34)	X	X	
4(c)(10)	—	Twenty-Third Supplemental Indenture to Exhibit 4(c)(1) dated as of March 17, 2014	CenterPoint Energy's Form 10-Q for the quarter ended March 31, 2014	1-31447	4.10	X	X	
4(c)(11)	—	Officer's Certificate, dated as of March 17, 2014, setting forth the form, terms and provisions of the Twenty-Third Series of General Mortgage Bonds	CenterPoint Energy's Form 10-Q for the quarter ended March 31, 2014	1-31447	4.11	X	X	

Exhibit Number		Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference	CenterPoint Energy	Houston Electric	CERC
4(c)(12)	—	Twenty-Fifth Supplemental Indenture to Exhibit 4(c)(1) dated as of August 11, 2016	CenterPoint Energy's Form 10-Q for the quarter ended September 30, 2016	1-31447	4.5	X	X	
4(c)(13)	—	Officer's Certificate, dated as of August 11, 2016, setting forth the form, terms and provisions of the Twenty-Sixth Series of General Mortgage Bonds	CenterPoint Energy's Form 10-Q for the quarter ended September 30, 2016	1-31447	4.6	X	X	
4(c)(14)	—	Twenty-Sixth Supplemental Indenture to Exhibit 4(c)(1) dated as of January 12, 2017	CenterPoint Energy's Form 10-K for the year ended December 31, 2016	1-31447	4(e)(41)	X	X	
4(c)(15)	—	Officer's Certificate, dated as of January 12, 2017, setting forth the form, terms and provisions of the Twenty-Seventh Series of General Mortgage Bonds	CenterPoint Energy's Form 10-K for the year ended December 31, 2016	1-31447	4(e)(42)	X	X	
4(c)(16)	—	Twenty-Seventh Supplemental Indenture to Exhibit 4(c)(1) dated as of February 28, 2018	CenterPoint Energy's Form 10-Q for the quarter ended March 30, 2018	1-31447	4.9	X	X	
4(c)(17)	—	Officer's Certificate, dated as of February 28, 2018, setting forth the form, terms and provisions of the Twenty-Eighth Series of General Mortgage Bonds	CenterPoint Energy's Form 10-Q for the quarter ended March 30, 2018	1-31447	4.10	X	X	
4(c)(18)	—	Twenty-Eighth Supplemental Indenture to Exhibit 4(c)(1) dated as of January 15, 2019	Houston Electric's Form 8-K dated January 10, 2019	1-3187	4.4	X	X	
4(c)(19)	—	Officer's Certificate, dated as of January 15, 2019, setting forth the form, terms and provisions of the Twenty-Ninth Series of General Mortgage Bonds	CenterPoint Energy's Form 10-K for the year ended December 31, 2018	1-31447	4(h)(24)	X	X	
4(c)(20)	—	Twenty-Ninth Supplemental Indenture to Exhibit 4(c)(1) dated as of June 5, 2020	Houston Electric's Form 8-K dated June 2, 2020	1-3187	4.4	X	X	
4(c)(21)	—	Officer's Certificate, dated as of June 5, 2020, setting forth the form, terms and provisions of the Thirtieth Series of General Mortgage Bonds	CenterPoint Energy's Form 10-Q for the quarter ended June 30, 2020	1-31447	4.26	X	X	
4(c)(22)	—	Thirtieth Supplemental Indenture to Exhibit 4(c)(1), dated as of March 11, 2021	Houston Electric's Form 8-K dated March 8, 2021	1-3187	4.4	X	X	
4(c)(23)	—	Officer's Certificate, dated as of March 11, 2021, setting forth the form, terms and provisions of the Thirty-First and Thirty-Second Series of General Mortgage Bonds	CenterPoint Energy's Form 10-Q for the quarter ended March 31, 2021	1-31447	4.22	X	X	

Exhibit Number		Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference	CenterPoint Energy	Houston Electric	CERC
4(c)(24)	—	Thirty-First Supplemental Indenture to Exhibit 4(c)(1), dated as of February 28, 2022	Houston Electric's Form 8-K dated February 23, 2022	1-3187	4.4		X	
4(c)(25)	—	Officer's Certificate, dated as of February 28, 2022, setting forth the form, terms and provisions of the Thirty-Third and Thirty-Fourth Series of General Mortgage Bonds	CenterPoint Energy's Form 10-Q for the quarter ended March 31, 2022	1-31447	4.11		X	
4(c)(26)	—	Thirty-Second Supplemental Indenture to Exhibit 4(c)(1), dated as of September 15, 2022	Houston Electric's Form 8-K dated September 12, 2022	1-3187	4.4		X	
4(c)(27)	—	Officer's Certificate, dated September 15, 2022, setting forth the form, terms and provisions of the Thirty-Fifth and Thirty-Sixth Series of General Mortgage Bonds	CenterPoint Energy's Form 10-Q for the quarter ended September 30, 2022	1-31447	4.7		X	
4(c)(28)	—	Thirty-Third Supplemental Indenture to Exhibit 4(c)(1), dated as of March 23, 2023	Houston Electric's Form 8-K dated March 20, 2023	1-3187	4.4		X	
4(c)(29)	—	Officer's Certificate, dated March 23, 2023, setting forth the form, terms and provisions of the Thirty-Seventh and Thirty-Eighth Series of General Mortgage Bonds	CenterPoint Energy's Form 10-Q for the quarter ended March 31, 2023	1-31447	4.11		X	
4(c)(30)	—	Thirty-Fourth Supplemental Indenture to Exhibit 4(c)(1), dated as of September 18, 2023	Houston Electric's Form 8-K dated September 13, 2023	1-3187	4.4		X	
4(c)(31)	—	Officer's Certificate, dated September 18, 2023, setting forth the form, terms and provisions of the Thirty-Ninth Series of General Mortgage Bonds	CenterPoint Energy's Form 10-Q for the quarter ended September 30, 2023	1-31447	4.9		X	
4(c)(32)	—	Thirty-Fifth Supplemental Indenture to Exhibit 4(c)(1), dated as of February 29, 2024	Houston Electric's Form 8-K dated February 26, 2024	1-3187	4.4		X	
4(c)(33)	—	Officer's Certificate, dated as of February 29, 2024, setting forth the form, terms and provisions of the Fortieth Series of General Mortgage Bonds	CenterPoint Energy's Form 10-Q for the quarter ended March 31, 2024	1-31447	4.6		X	
4(c)(34)	—	Thirty-Sixth Supplemental Indenture to Exhibit 4(c)(1), dated as of November 4, 2024	Houston Electric's Form 8-K dated October 31, 2024	1-3187	4.4		X	

Exhibit Number		Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference	CenterPoint Energy	Houston Electric	CERC
†4(c)(35)	—	Officer's Certificate, dated as of November 4, 2024, setting forth the form, terms and provisions of the Forty-First Series of General Mortgage Bonds					X	
4(d)(1)	—	Indenture, dated as of February 1, 1998, between Reliant Energy Resources Corp. (RERC Corp.) and Chase Bank of Texas, National Association, as Trustee	CERC Corp.'s Form 8-K dated February 5, 1998	1-13265	4.1	X		X
4(d)(2)	—	Supplemental Indenture No. 10 to Exhibit 4(d)(1), dated as of February 6, 2007, providing for the issuance of CERC Corp.'s 6.25% Senior Notes due 2037	CenterPoint Energy's Form 10-K for the year ended December 31, 2006	1-31447	4(f)(11)	X		X
4(d)(3)	—	Supplemental Indenture No. 12 to Exhibit 4(d)(1) dated as of October 23, 2007, providing for the issuance of CERC Corp.'s 6.625% Senior Notes due 2037	CenterPoint Energy's Form 10-Q for the quarter ended June 30, 2008	1-31447	4.9	X		X
4(d)(4)	—	Supplemental Indenture No. 14 to Exhibit 4(d)(1) dated as of January 11, 2011, providing for the issuance of CERC Corp.'s 4.50% Senior Notes due 2021 and 5.85% Senior Notes due 2041	CenterPoint Energy's Form 10-K for the year ended December 31, 2010	1-31447	4(f)(15)	X		X
4(d)(5)	—	Supplemental Indenture No. 16 to Exhibit 4(d)(1) dated as of August 23, 2017, providing for the issuance of CERC Corp.'s 4.10% Senior Notes due 2047	CenterPoint Energy's Form 10-Q for the quarter ended September 30, 2017	1-31447	4.11	X		X
4(d)(6)	—	Supplemental Indenture No. 17 to Exhibit 4(d)(1) dated as of March 28, 2018, providing for the issuance of CERC Corp.'s 3.55% Senior Notes due 2023 and 4.00% Senior Notes due 2028	CERC's Form 10-Q for the quarter ended March 31, 2018	1-13265	4.4	X		X
4(d)(7)	—	Supplemental Indenture No. 18 to Exhibit 4(d)(1), dated as of October 1, 2020, providing for the issuance of CERC Corp.'s 1.75% Senior Notes due 2030	CenterPoint Energy's Form 10-Q for the quarter ended September 30, 2020	1-31447	4.23	X		X
4(d)(8)	—	Supplemental Indenture No. 21, dated as of June 9, 2022, to the Indenture under Exhibit 4(d)(1)	CenterPoint Energy's Form 10-Q for the quarter ended June 30, 2022	1-31447	4.12			X
4(d)(9)	—	Supplemental Indenture No. 22, to Exhibit 4(d)(1), dated as of October 5, 2022, providing for the issuance of CERC Corp.'s 6.10% Senior Notes due 2035	CERC's Form 8-K dated October 5, 2022	1-13265	4.2			X

Exhibit Number		Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference	CenterPoint Energy	Houston Electric	CERC
4(d)(10)	—	Supplemental Indenture No. 23 to Exhibit 4(d)(1), dated as of February 23, 2023, providing for the issuance of CERC Corp.'s 5.25% Senior Notes due 2028 and 5.40% Senior Notes due 2033	CenterPoint Energy's Form 10-Q for the quarter ended March 31, 2023	1-31447	4.6			X
4(d)(11)	—	Supplemental Indenture No. 24 to Exhibit 4(d)(1), dated as of May 3, 2023, providing for the issuance of CERC Corp.'s 5.25% Senior Notes due 2028	CenterPoint Energy's Form 10-Q for the quarter ended June 30, 2023	1-31447	4.5			X
4(d)(12)	—	Supplemental Indenture No. 25 to Exhibit 4(d)(1), dated as of June 20, 2024, providing for the issuance of CERC Corp.'s 5.40% Senior Notes due 2034	CenterPoint Energy's Form 10-Q for the quarter ended June 30, 2024	1-31447	4.5			X
4(e)(1)	—	Indenture, dated as of May 19, 2003, between CenterPoint Energy and JPMorgan Chase Bank, as Trustee	CenterPoint Energy's Form 8-K dated May 19, 2003	1-31447	4.1	X		
4(e)(2)	—	Supplemental Indenture No. 10 to Exhibit 4(e)(1), dated as of October 5, 2018, providing for the issuance of CenterPoint Energy's 3.60% Senior Notes due 2021, 3.85% Senior Notes due 2024 and 4.25% Senior Notes due 2028	CenterPoint Energy's Form 10-Q for the quarter ended September 30, 2018	1-31447	4.14	X		
4(e)(3)	—	Supplemental Indenture No. 11 to Exhibit 4(e)(1), dated as of August 14, 2019, providing for the issuance of CenterPoint Energy's 2.50% Senior Notes due 2024, 2.95% Senior Notes due 2030 and 3.70% Senior Notes due 2049	CenterPoint Energy's Form 10-Q for the quarter ended September 30, 2019	1-31447	4.2	X		
4(e)(4)	—	Supplemental Indenture No. 13 to Exhibit 4(e)(1), dated as of May 13, 2021, providing for the issuance of CenterPoint Energy's 1.45% Senior Notes due 2026 and 2.65% Senior Notes due 2031	CenterPoint Energy's Form 10-Q for the quarter ended June 30, 2021	1-31447	4.25	X		
4(e)(5)	—	Supplemental Indenture No. 14 to Exhibit 4(e)(1), dated as of August 10, 2023, providing for the issuance of CenterPoint Energy's 5.25% Senior Notes due 2026	CenterPoint Energy's Form 10-Q for the quarter ended September 30, 2023	1-31447	4.4	X		
4(e)(6)	—	Supplemental Indenture No. 15 to Exhibit 4(e)(1), dated as of May 10, 2024, providing for the issuance of CenterPoint Energy's 5.40% Senior Notes due 2029	CenterPoint Energy's Form 10-Q for the quarter ended June 30, 2024	1-31447	4.3	X		
4(f)(1)	—	Subordinated Indenture dated as of September 1, 1999	Reliant Energy's Form 8-K dated September 1, 1999	1-3187	4.1	X		

Exhibit Number		Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference	CenterPoint Energy	Houston Electric	CERC
4(f)(2)	—	Supplemental Indenture No. 1 dated as of September 1, 1999, between Reliant Energy and Chase Bank of Texas (supplementing Exhibit 4(f)(1) and providing for the issuance Reliant Energy's 2% Zero-Premium Exchangeable Subordinated Notes Due 2029)	Reliant Energy's Form 8-K dated September 15, 1999	1-3187	4.2	X		
4(f)(3)	—	Supplemental Indenture No. 2 dated as of August 31, 2002, between CenterPoint Energy, Reliant Energy and JPMorgan Chase Bank (supplementing Exhibit 4(f)(1))	CenterPoint Energy's Form 8-K12B dated August 31, 2002	1-31447	4(e)	X		
4(f)(4)	—	Supplemental Indenture No. 3 dated as of December 28, 2005, between CenterPoint Energy, Reliant Energy and JPMorgan Chase Bank (supplementing Exhibit 4(f)(1))	CenterPoint Energy's Form 10-K for the year ended December 31, 2005	1-31447	4(h)(4)	X		
4(g)(1)	—	Amended and Restated Indenture of Mortgage and Deed of Trust dated as of January 1, 2023, between SIGECO and Deutsche Bank Trust Company Americas, as Trustee	CenterPoint Energy's Form 8-K dated January 30, 2023	1-31447	10.2	X		
4(g)(2)	—	First Supplemental Indenture to Exhibit 4(g)(1), dated as of March 15, 2023	CenterPoint Energy's Form 8-K dated March 15, 2023	1-31447	4.2	X		
4(g)(3)	—	Second Supplemental Indenture to Exhibit 4(g)(1), dated as of October 13, 2023	CenterPoint Energy's Form 8-K dated October 13, 2023	1-31447	4.2	X		
4(g)(4)	—	Third Supplemental Indenture dated as of August 29, 2024, between Southern Indiana Gas and Electric Company and Deutsche Bank Trust Company Americas, as Trustee	CenterPoint Energy's Form 8-K dated August 29, 2024	1-31447	4.2	X		
†4(g)(5)	—	Fourth Supplemental Indenture dated as of January 31, 2025, between Southern Indiana Gas and Electric Company and Deutsche Bank Trust Company Americas, as Trustee				X		
4(g)(6)	—	Additional Supplemental Indentures to Exhibit 4(g)(1)				X		
		Date as of	**File Reference**	**Exhibit No.**				
		July 1, 1999	1-3553, SIGECO's Form 10-Q for the quarter ended June 30, 1999	4(a)				

Exhibit Number		Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference	CenterPoint Energy	Houston Electric	CERC
		April 1, 2013	1-15467, Vectren's Form 8-K dated April 30, 2013	4.1				
		September 1, 2014	1-15467, Vectren's Form 8-K dated September 25, 2014	4.1				
		September 1, 2015	1-15467, Vectren's Form 8-K dated September 10, 2015	4.1				
4(h)(1)	—	Indenture dated February 1, 1991 between Indiana Gas Company, Inc. and U.S Bank Trust National Association (formerly known as First Trust National Association, which was formerly known as Bank of America Illinois, which was formerly known as Continental Bank, National Association)	Indiana Gas's Form 8-K filed February 15, 1991	1-6494	4(a)	X		
4(h)(2)	—	First Supplemental Indenture to Exhibit 4(h)(1), dated as of February 15, 1991	Indiana Gas's Form 8-K filed February 15, 1991	1-6494	4(b)	X		
4(h)(3)	—	Second Supplemental Indenture to Exhibit 4(h)(1), dated as of September 15, 1991	Indiana Gas's Form 8-K filed September 25, 1991	1-6494	4(b)	X		
4(h)(4)	—	Third Supplemental Indenture to Exhibit 4(h)(1), dated as of September 15, 1991	Indiana Gas's Form 8-K filed September 25, 1991	1-6494	4(c)	X		
4(h)(5)	—	Fourth Supplemental Indenture to Exhibit 4(h)(1), dated as of December 2, 1992	Indiana Gas's Form 8-K filed December 8, 1992	1-6494	4(b)	X		
4(h)(6)	—	Fifth Supplemental Indenture to Exhibit 4(h)(1), dated as of December 28, 2000	Indiana Gas's Form 8-K filed December 27, 2000	1-6494	4	X		
4(i)(1)	—	Bond Purchase and Covenants Agreement, dated September 14, 2017, between SIGECO and PNC Bank, National Association	Vectren's Form 8-K dated September 25, 2017	1-15467	4.1	X		
4(i)(2)	—	Joinder and First Amendment to Exhibit 4(i)(1) dated March 1, 2018 among SIGECO, the lenders party thereto and PNC Bank, National Association	Vectren's Form 8-K dated May 3, 2018	1-15467	4.1	X		
4(i)(3)	—	Second Amendment to Exhibit 4(i)(1) dated May 1, 2018 among SIGECO, the lenders party thereto and PNC Bank, National Association	Vectren's Form 8-K dated May 3, 2018	1-15467	4.2	X		
4(i)(4)	—	Third Amendment to Exhibit 4(i)(1) dated December 7, 2022 among SIGECO, the lenders party thereto and PNC Bank, National Association	CenterPoint Energy's Form 10-K for the year ended December 31, 2022	1-31447	4(k)(4)	X		

Exhibit Number		Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference	CenterPoint Energy	Houston Electric	CERC
4(j)	—	The Note Purchase Agreement, dated as of May 27, 2022, between CERC and the Purchasers signatory thereto, in connection with the issuance by CERC of $40,000,000 aggregate principal amount of CERC's 4.36% Senior Notes, Series B, due December 15, 2045	CenterPoint Energy's Form 8-K dated May 27, 2022	1-31447	4.1	X		X
4(k)	—	The Note Purchase Agreement, dated as of May 27, 2022, between CERC and the Purchasers signatory thereto, in connection with the issuance by CERC of $10,000,000 aggregate principal amount of CERC's 4.25% Senior Notes, Series B, due June 5, 2043	CenterPoint Energy's Form 8-K dated May 27, 2022	1-31447	4.3	X		X
4(l)	—	The Note Purchase Agreement, dated as of May 27, 2022, between CERC and the Purchasers signatory thereto, in connection with the issuance by CERC of $100,000,000 aggregate principal amount of CERC's 5.00% Senior Notes, due February 3, 2042	CenterPoint Energy's Form 8-K dated May 27, 2022	1-31447	4.4	X		X
4(m)	—	The Note Purchase Agreement, dated as of May 27, 2022, between CERC and the Purchasers signatory thereto, in connection with the issuance by CERC of $60,000,000 aggregate principal amount of CERC's 5.02% Senior Notes, Series B, due November 30, 2026 and $35,000,000 aggregate principal amount of CERC's 5.99% Senior Notes, Series C, due November 30, 2041	CenterPoint Energy's Form 8-K dated May 27, 2022	1-31447	4.5	X		X
4(n)	—	Registration Rights Agreement, dated as of October 5, 2022, between CenterPoint Energy Resources Corp. and Goldman Sachs & Co. LLC	CERC's Form 8-K dated October 5, 2022	1-13265	4.3			X
4(o)	—	Indenture dated as of August 4, 2023, between CenterPoint Energy and The Bank of New York Mellon Trust Company, National Association, as trustee	CenterPoint Energy's Form 8-K dated August 4, 2023	1-31447	4.1	X		
4(p)(1)	—	Junior Subordinated Indenture, dated as of August 14, 2024, between CenterPoint Energy, Inc. and The Bank of New York Mellon Trust Company, National Association, as trustee	CenterPoint Energy's Form 10-Q for the quarter ended September 30, 2024	1-31447	4.1	X		
4(p)(2)	—	Supplemental Indenture to Exhibit 4(p)(1), dated as of August 14, 2024	CenterPoint Energy's Form 10-Q for the quarter ended September 30, 2024	1-31447	4.2	X		

Exhibit Number		Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference	CenterPoint Energy	Houston Electric	CERC
†4(p)(3)	—	Supplemental Indenture No. 2 to Exhibit 4(p)(1), dated as of October 31, 2024, providing for the issuance of CenterPoint Energy's 6.700% Fixed-to-Fixed Reset Junior Subordinated Notes, Series C, due 2055				X		
†4(q)	—	Description of CenterPoint Energy's Securities				X		
†4(r)	—	Description of Houston Electric's Securities					X	
†4(s)	—	Description of CERC's Securities						X

Pursuant to Item 601(b)(4)(iii)(A) of Regulation S-K, the Registrants have not filed as exhibits to this Form 10-K certain long-term debt instruments, including indentures, under which the total amount of securities authorized does not exceed 10% of the total assets of the Registrants and its subsidiaries on a consolidated basis. The Registrants hereby agree to furnish a copy of any such instrument to the SEC upon request.

Exhibit Number		Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference	CenterPoint Energy	Houston Electric	CERC
*10(a)	—	CenterPoint Energy, Inc. 1991 Benefit Restoration Plan, as amended and restated effective as of February 25, 2011	CenterPoint Energy's Form 10-Q for the quarter ended March 31, 2011	1-31447	10.3	X		
*10(b)(1)	—	CenterPoint Energy Benefit Restoration Plan, effective as of January 1, 2008	CenterPoint Energy's Form 8-K dated December 22, 2008	1-31447	10.1	X		
*10(b)(2)	—	First Amendment to Exhibit 10(b)(1), effective as of February 25, 2011	CenterPoint Energy's Quarterly Report on Form 10-Q for the quarter ended March 31, 2011	1-31447	10.4	X		
*10(b)(3)	—	Partial Termination Amendment to Exhibit 10(b)(1), effective as of March 1, 2022	CenterPoint Energy's Quarterly Report on Form 10-Q for the quarter ended March 31, 2022	1-31447	10.14	X		
*10(b)(4)	—	Third Amendment to Exhibit 10(b)(1), effective as of October 1, 2023	CenterPoint Energy's Quarterly Report on Form 10-Q for the quarter ended September 30, 2023	1-31447	10.2	X		
*10(c)	—	CenterPoint Energy 1985 Deferred Compensation Plan, as amended and restated effective January 1, 2003	CenterPoint Energy's Form 10-Q for the quarter ended September 30, 2003	1-31447	10.1	X		
*10(d)(1)	—	Amended and Restated CenterPoint Energy, Inc. 1991 Savings Restoration Plan, effective as of January 1, 2008	CenterPoint Energy's Form 8-K dated December 22, 2008	1-31447	10.4	X		

Exhibit Number		Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference	CenterPoint Energy	Houston Electric	CERC
*10(d)(2)	—	First Amendment to Exhibit 10(d)(1), effective as of February 25, 2011	CenterPoint Energy's Quarterly Report on Form 10-Q for the quarter ended March 31, 2011	1-31447	10.5	X		
*10(e)(1)	—	CenterPoint Energy Savings Restoration Plan, effective as of January 1, 2008	CenterPoint Energy's Form 8-K dated December 22, 2008	1-31447	10.3	X		
*10(e)(2)	—	First Amendment to Exhibit 10(e)(1), effective as of February 25, 2011	CenterPoint Energy's Quarterly Report on Form 10-Q for the quarter ended March 31, 2011	1-31447	10.6	X		
*10(e)(3)	—	Second Amendment to Exhibit 10(e)(1), effective as of January 1, 2020	CenterPoint Energy's Form 8-K dated December 9, 2019	1-31447	10.1	X		
*10(e)(4)	—	Partial Termination Amendment to Exhibit 10(e)(1), effective as of March 1, 2022	CenterPoint Energy's Quarterly Report on Form 10-Q for the quarter ended March 31, 2022	1-31447	10.18	X		
*10(e)(5)	—	Fourth Amendment to Exhibit 10(e)(1), effective as of October 1, 2023	CenterPoint Energy's Quarterly Report on Form 10-Q for the quarter ended September 30, 2023	1-31447	10.3	X		
*10(e)(6)	—	Fifth Amendment to Exhibit 10(e)(1), effective as of January 1, 2024	CenterPoint Energy's Form 10-K for the year ended December 31, 2013	1-31447	10(e)(6)	X		
*10(e)(7)	—	Partial Termination Amendment to Exhibit 10(e)(1), effective as of April 1, 2024	CenterPoint Energy's Form 10-K for the year ended December 31, 2013	1-31447	10(e)(7)	X		
*10(f)	—	CenterPoint Energy Executive Life Insurance Plan, as amended and restated effective June 18, 2003	CenterPoint Energy's Form 10-Q for the quarter ended September 30, 2003	1-31447	10.5	X		
10(g)(1)	—	Stockholder's Agreement dated as of July 6, 1995 between Houston Industries Incorporated and Time Warner Inc.	Schedule 13-D dated July 6, 1995	5-19351	2	X		
10(g)(2)	—	Amendment to Exhibit 10(g)(1) dated November 18, 1996	HI's Form 10-K for the year ended December 31, 1996	1-7629	10(x)(4)	X		

Exhibit Number		Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference	CenterPoint Energy	Houston Electric	CERC
10(h)(1)	—	Master Separation Agreement entered into as of December 31, 2000 between Reliant Energy, Incorporated and Reliant Resources, Inc.	Reliant Energy's Form 10-Q for the quarter ended March 31, 2001	1-3187	10.1	X		
10(h)(2)	—	First Amendment to Exhibit 10(h)(1) effective as of February 1, 2003	CenterPoint Energy's Form 10-K for the year ended December 31, 2002	1-31447	10(bb)(5)	X		
10(h)(3)	—	Employee Matters Agreement, entered into as of December 31, 2000, between Reliant Energy, Incorporated and Reliant Resources, Inc.	Reliant Energy's Form 10-Q for the quarter ended March 31, 2001	1-3187	10.5	X		
10(h)(4)	—	Retail Agreement, entered into as of December 31, 2000, between Reliant Energy, Incorporated and Reliant Resources, Inc.	Reliant Energy's Form 10-Q for the quarter ended March 31, 2001	1-3187	10.6	X		
10(h)(5)	—	Tax Allocation Agreement, entered into as of December 31, 2000, between Reliant Energy, Incorporated and Reliant Resources, Inc.	Reliant Energy's Form 10-Q for the quarter ended March 31, 2001	1-3187	10.8	X		
10(i)(1)	—	Separation Agreement entered into as of August 31, 2002 between CenterPoint Energy and Texas Genco	CenterPoint Energy's Form 10-K for the year ended December 31, 2002	1-31447	10(cc)(1)	X		
10(i)(2)	—	Transition Services Agreement, dated as of August 31, 2002, between CenterPoint Energy and Texas Genco	CenterPoint Energy's Form 10-K for the year ended December 31, 2002	1-31447	10(cc)(2)	X		
10(i)(3)	—	Tax Allocation Agreement, dated as of August 31, 2002, between CenterPoint Energy and Texas Genco	CenterPoint Energy's Form 10-K for the year ended December 31, 2002	1-31447	10(cc)(3)	X		
*10(j)(1)	—	CenterPoint Energy, Inc. Deferred Compensation Plan, as amended and restated effective January 1, 2003	CenterPoint Energy's Form 10-Q for the quarter ended June 30, 2003	1-31447	10.2	X		
*10(j)(2)	—	First Amendment to Exhibit 10(j)(1) effective as of January 1, 2008	CenterPoint Energy's Form 8-K dated February 20, 2008	1-31447	10.4	X		
*10(k)(1)	—	Amended and Restated CenterPoint Energy 2005 Deferred Compensation Plan, effective January 1, 2009	CenterPoint Energy's Form 10-Q for the quarter ended September 30, 2008	1-31447	10.1	X		
*10(k)(2)	—	First Amendment to Exhibit 10(k)(1) effective March 1, 2022	CenterPoint Energy's Form 8-K dated April 22, 2022	1-31447	10.10	X		

Exhibit Number		Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference	CenterPoint Energy	Houston Electric	CERC
*10(k)(3)	—	Second Amendment to Exhibit 10(k)(1) effective May 1, 2022	CenterPoint Energy's Form 10-Q for the quarter ended March 31, 2022	1-31447	10.11	X		
*10(k)(4)	—	Third Amendment to Exhibit 10(k)(1) effective October 1, 2023	CenterPoint Energy's Form 10-Q for the quarter ended September 30, 2023	1-31447	10.1	X		
*10(k)(5)	—	Partial Termination Amendment to Exhibit 10(k)(1) effective April 1, 2024	CenterPoint Energy Form 10-K for the year ended December 31, 2023	1-31447	10(l)	X		
*10(l)(1)	—	CenterPoint Energy Inc., Short Term Incentive Plan, as amended and restated effective January 1, 2022	CenterPoint Energy Form 10-K for the year ended December 31, 2021	1-31447	10(l)	X		
*10(l)(2)	—	First Amendment to Exhibit 10(l)(1) effective as of January 1, 2023	CenterPoint Energy Form 10-K for the year ended December 31, 2022	1-31447	10(l)(2)	X		
*10(m)(1)	—	Amended and Restated CenterPoint Energy Stock Plan for Outside Directors	CenterPoint Energy's Form 10-Q for the quarter ended March 31, 2018	1-31447	10.1	X		
*10(m)(2)		First Amendment to Exhibit 10(m)(1), dated as of February 19, 2020	CenterPoint Energy's Form 10-K for the year ended December 31, 2019	1-31447	10(n)(2)	X		
†*10(m)(2)		Second Amendment to Exhibit 10(m)(1), dated as of February 14, 2025				X		
10(n)	—	City of Houston Franchise Ordinance	CenterPoint Energy's Form 10-Q for the quarter ended June 30, 2005	1-31447	10.1	X	X	
10(o)(1)	—	Amended and Restated HL&P Executive Incentive Compensation Plan effective as of January 1, 1985	CenterPoint Energy's Form 10-Q for the quarter ended September 30, 2008	1-31447	10.2	X		
10(o)(2)	—	First Amendment to Exhibit 10(o)(1) effective as of January 1, 2008	CenterPoint Energy's Form 10-Q for the quarter ended September 30, 2008	1-31447	10.3	X		
*10(p)(1)	—	CenterPoint Energy, Inc. 2009 Long Term Incentive Plan	CenterPoint Energy's Schedule 14A dated March 13, 2009	1-31447	A	X		

Exhibit Number		Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference	CenterPoint Energy	Houston Electric	CERC
*10(p)(2)	—	Form of Performance Award Agreement for 20XX - 20XX Performance Cycle under Exhibit 10(p)(1)	CenterPoint Energy's Form 10-K for the year ended December 31, 2019	1-31447	10(q)(2)	X		
*10(p)(3)	—	Form of Restricted Stock Unit Award Agreement (Service-Based Vesting) under Exhibit 10(p)(1)	CenterPoint Energy's Form 10-K for the year ended December 31, 2019	1-31447	10(q)(5)	X		
*10(p)(4)	—	Form of Restricted Stock Unit Award Agreement (Retention, Service-Based Vesting) under Exhibit 10(p)(1)	CenterPoint Energy's Form 8-K dated June 30, 2020	1-31447	10.4	X		
*10(p)(5)	—	Form of Performance Award Agreement for the Chief Executive Officer under Exhibit 10(p)(1)	CenterPoint Energy's Form 8-K dated June 30, 2020	1-31447	10.2	X		
*10(p)(6)	—	Form of Restricted Stock Unit Award Agreement for the Chief Executive Officer under Exhibit 10(p)(1)	CenterPoint Energy's Form 8-K dated June 30, 2020	1-31447	10.3	X		
*10(p)(7)	—	Form of Award Agreement for Performance Share Units for Named Executive Officers (Separation) under Exhibit 10(p)(1)	CenterPoint Energy's Form 8-K/A dated June 30, 2020	1-31447	10.1	X		
*10(p)(8)	—	Form of Award Agreement for Restricted Stock Units for Named Executive Officers (Separation) under Exhibit 10(p)(1)	CenterPoint Energy's Form 8-K/A dated June 30, 2020	1-31447	10.2	X		
*10(p)(9)	—	Form of Restricted Stock Unit Award Agreement (Service-Based Vesting with Performance Goals) under Exhibit 10(p)(1)	CenterPoint Energy's Form 10-K for the year ended December 31, 2020	1-31447	10(q)(12)	X		
*10(p)(10)	—	Form of Restricted Stock Unit Award Agreement for CEO (Service-Based Vesting with Performance Goals) under Exhibit 10(p)(1)	CenterPoint Energy's Form 10-K for the year ended December 31, 2020	1-31447	10(q)(13)	X		
*10(p)(11)	—	Form of Restricted Stock Unit Award Agreement (Fully Vested) under Exhibit 10(p)(1)	CenterPoint Energy's Form 8-K/A dated February 19, 2020	1-31447	10.1	X		
*10(p)(12)	—	Form of Restricted Stock Unit Award Agreement for the Chief Executive Officer under Exhibit 10(p)(1)	CenterPoint Energy's Form 8-K dated July 20, 2021	1-31447	10.1	X		
*10(q)(1)	—	Change in Control Plan	CenterPoint Energy's Form 8-K dated April 27, 2017	1-31447	10.1	X		
*10(q)(2)	—	First Amendment to Exhibit 10(q)(1)	CenterPoint Energy's Form 10-K for the year ended December 31, 2020	1-31447	10(t)(2)	X		

Exhibit Number		Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference	CenterPoint Energy	Houston Electric	CERC
*10(q)(3)	—	Second Amendment to Exhibit 10(q)(1)	CenterPoint Energy's Form 10-K for the year ended December 31, 2021	1-31447	10(q)(3)	X		
*10(q)(4)	—	Third Amendment to Exhibit 10(q)(1)	CenterPoint Energy's Form 10-Q for the quarter ended March 31, 2024	1-31447	10.1	X		
*10(r)	—	Omnibus Amendment to CenterPoint Energy, Inc. Benefit Plans, dated May 23, 2013	CenterPoint Energy's Form 10-K for the year ended December 31, 2013	1-31447	10(zz)	X		
*10(s)(1)	—	Vectren Non-Qualified Deferred Compensation Plan, as amended and restated effective January 1, 2001	Vectren's Form 10-K for the year end December 31, 2001	1-15467	10.32	X		
*10(s)(2)	—	July 1, 2002 Amendment to Exhibit 10(s)(1)	CenterPoint Energy's Form 10-K for the year ended December 31, 2023	1-31447	10(s)(2)	X		
*10(t)(1)	—	Vectren Corporation Non-Qualified Deferred Compensation Plan, effective January 1, 2005	Vectren's Form 8-K dated September 29, 2008	1-15467	10.3	X		
*10(t)(2)	—	Partial Termination Amendment to Exhibit 10(t)(1), effective as of January 1, 2005	CenterPoint Energy's Form 10-Q for the quarter ended March 31, 2024	1-31447	10.2	X		
*10(u)(1)	—	Vectren Nonqualified Defined Benefit Restoration Plan, as amended and restated effective January 1, 2005	Vectren's Form 8-K dated December 17, 2008	1-15467	10.2	X		
*10(u)(2)	—	First Amendment to Exhibit 10(u)(1)	CenterPoint Energy's Form 10-K for the year ended December 31, 2023	1-31447	10(u)(2)	X		
*10(v)	—	Vectren Unfunded Supplemental Retirement Plan for a Select Group of Management Employees (As Amended and Restated Effective January 1, 2005)	Vectren's Form 8-K dated December 17, 2008	1-15467	10.1	X		
*10(w)	—	Vectren Specimen Waiver, effective October 3, 2013, to the Vectren Unfunded Supplemental Retirement Plan for a Select Group of Management Employees	Vectren's Form 10-Q for the quarter ended September 30, 2013	1-15467	10.1	X		
*10(x)(1)	—	CenterPoint Energy, Inc. 2022 Long Term Incentive Plan	CenterPoint Energy's Definitive Proxy Statement filed on March 11, 2022	1-31447	Appendix A	X		
*10(x)(2)	—	Form of Performance Award Agreement for 20XX-20XX Performance Cycle for the CEO under Exhibit 10(x)(1)	CenterPoint Energy's 8-K dated April 22, 2022	1-31447	10.2	X		

Exhibit Number		Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference	CenterPoint Energy	Houston Electric	CERC
*10(x)(3)	—	Form of Performance Award Agreement for 20XX-20XX Performance Cycle for officers and director employees under Exhibit 10(x)(1)	CenterPoint Energy's 8-K dated April 22, 2022	1-31447	10.3	X		
*10(x)(4)	—	Form of Restricted Stock Unit Award Agreement under Exhibit 10(x)(1)	CenterPoint Energy's 8-K dated April 22, 2022	1-31447	10.4	X		
*10(x)(5)	—	Form of Restricted Stock Unit Award Agreement for the CEO (with Performance Goals) under Exhibit 10(x)(1)	CenterPoint Energy's 8-K dated April 22, 2022	1-31447	10.5	X		
*10(x)(6)	—	Form of Restricted Stock Unit Award Agreement for Officers and Director Employees (with Performance Goals) under Exhibit 10(x)(1)	CenterPoint Energy's 8-K dated April 22, 2022	1-31447	10.7	X		
*10(x)(7)	—	Form of Restricted Stock Unit Award Agreement for the CEO under Exhibit 10(x)(1)	CenterPoint Energy's 8-K dated April 22, 2022	1-31447	10.8	X		
*10(x)(8)	—	Form of Performance Award Agreement for the President and Chief Operating Officer under Exhibit 10(x)(1)	CenterPoint Energy's 10-K for the year ended December 31, 2022	1-31447	10(ee)(9)	X		
*10(x)(9)	—	Form of Restricted Stock Unit Award Agreement for President and Chief Operating Officer (with Performance Goals) under Exhibit 10(x)(1)	CenterPoint Energy's 10-K for the year ended December 31, 2022	1-31447	10(ee)(10)	X		
*10(x)(10)	—	Form of Restricted Stock Unit Award Agreement under Exhibit 10(x)(1)	CenterPoint Energy's Form 8-K dated March 15, 2023	1-31447	10.2	X		
*10(x)(11)	—	Form of Award Agreement for Performance Share Units for Officer and Director Employees under Exhibit 10(x)(1)	CenterPoint Energy's Form 8-K dated September 27, 2023	1-31447	10.1	X		
*10(x)(12)		Form of Award Agreement for Restricted Stock Units for Officer and Director under Exhibit 10(x)(1)	CenterPoint Energy's Form 8-K dated September 27, 2023	1-31447	10.2	X		
*10(x)(13)		Form of Restricted Stock Unit Award Agreement for Officers and Director Employees (with Performance Goals) under Exhibit 10(x)(1)	CenterPoint Energy's 10-K for the year ended December 31, 2023	1-31447	10(cc)(13)	X		
*10(x)(14)		Form of Performance Award Agreement for Officers and Director Employees under Exhibit 10(x)(1)	CenterPoint Energy's 10-K for the year ended December 31, 2023	1-31447	10(cc)(14)	X		
*10(x)(15)		Form of Restricted Stock Unit Award Agreement under Exhibit 10(x)(1)	CenterPoint Energy's 10-K for the year ended December 31, 2023	1-31447	10(cc)(15)	X		

Exhibit Number		Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference	CenterPoint Energy	Houston Electric	CERC
10(y)(1)	—	$2,400,000,000 Amended and Restated Credit Agreement dated as of December 6, 2022 among CenterPoint Energy, Inc., as Borrower, JPMorgan Chase Bank, N.A., as Administrative Agent, the financial institutions as bank parties thereto and the other parties thereto	CenterPoint Energy's 8-K dated December 6, 2022	1-31447	10.1	X		
10(y)(2)	—	First Amendment to Exhibit 10(y)(1), dated as of July 26, 2023	CenterPoint Energy's Form 10-Q for the quarter ended June 30, 2023	1-31447	10.1	X		
10(z)	—	$300,000,000 Credit Agreement dated as of December 6, 2022 among CenterPoint Energy Houston Electric, LLC, as Borrower, Mizuho Bank, Ltd., as Administrative Agent, the financial institutions as bank parties thereto and the other parties thereto	CenterPoint Energy's 8-K dated December 6, 2022	1-31447	10.2		X	
10(aa)	—	$1,050,000,000 Credit Agreement dated as of December 6, 2022 among CenterPoint Energy Resources Corp., as Borrower, Wells Fargo Bank, National Association, as Administrative Agent, the financial institutions as bank parties thereto and the other parties thereto	CenterPoint Energy's 8-K dated December 6, 2022	1-31447	10.3			X
10(bb)	—	$250,000,000 Credit Agreement dated as of December 6, 2022 among Southern Indiana Gas and Electric Company, as Borrower, Wells Fargo Bank, National Association, as Administrative Agent, the financial institutions as bank parties thereto and the other parties thereto	CenterPoint Energy's 8-K dated December 6, 2022	1-31447	10.4	X		
10(cc)	—	Term Loan Agreement dated as of June 24, 2024 among CenterPoint Energy Houston Electric, LLC as borrower, Mizuho Bank, Ltd., as administrative agent, and the banks party thereto	CenterPoint Energy's Form 8-K dated June 24, 2024	1-31447	10.1	X	X	
10(dd)	—	Christopher A. Foster Offer Letter	CenterPoint Energy's Form 8-K dated March 15, 2023	1-31447	10.1	X		
10(ee)	—	Bond Purchase Agreement dated March 15, 2023 among SIGECO and the purchasers listed on Schedule B thereto	CenterPoint Energy's Form 8-K dated March 15, 2023	1-31447	10.1	X		

Exhibit Number		Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference	CenterPoint Energy	Houston Electric	CERC
10(ff)	—	Bond Purchase Agreement dated October 13, 2023 among SIGECO and the purchasers listed on Schedule B thereto	CenterPoint Energy's Form 8-K dated October 13, 2023	1-31447	10.1	X		
10(gg)	—	Bond Purchase Agreement dated August 29, 2024 among Southern Indiana Gas and Electric Company and the purchasers listed on Schedule B thereto	CenterPoint Energy's Form 8-K dated August 29, 2024	1-31447	10.1	X		
10(hh)	—	Equity Distribution Agreement, dated January 10, 2024, among CenterPoint Energy, Inc. and BofA Securities, Inc., Barclays Capital Inc., Citigroup Global Markets Inc., Goldman Sachs & Co. LLC, J.P. Morgan Securities LLC, Mizuho Securities USA LLC, MUFG Securities Americas Inc. and RBC Capital Markets, LLC, as managers, Bank of America, N.A., Barclays Bank PLC, Citibank, N.A., Goldman Sachs & Co. LLC, JPMorgan Chase Bank, National Association, Mizuho Markets Americas LLC, MUFG Securities EMEA plc and Royal Bank of Canada, as forward purchasers, and BofA Securities, Inc., Barclays Capital Inc., Citigroup Global Markets Inc., Goldman Sachs & Co. LLC, J.P. Morgan Securities LLC, Mizuho Securities USA LLC, MUFG Securities Americas Inc. and RBC Capital Markets, LLC, as forward sellers	CenterPoint Energy's Form 8-K dated January 10, 2024	1-31447	1.1	X		
†19	—	Insider Trading Policy				X		
†21.1	—	Subsidiaries of CenterPoint Energy				X		
†21.2	—	Subsidiaries of CERC Corp.						X
†23.1.1	—	Consent of Deloitte & Touche LLP				X		
†23.1.2	—	Consent of Deloitte & Touche LLP					X	
†23.1.3	—	Consent of Deloitte & Touche LLP						X
†31.1.1	—	Rule 13a-14(a)/15d-14(a) Certification of Jason P. Wells				X		
†31.1.2	—	Rule 13a-14(a)/15d-14(a) Certification of Darin M. Carroll					X	
†31.1.3	—	Rule 13a-14(a)/15d-14(a) Certification of Richard C. Leger						X
†31.2.1	—	Rule 13a-14(a)/15d-14(a) Certification of Christopher A. Foster				X		

Exhibit Number		Description	Report or Registration Statement	SEC File or Registration Number	Exhibit Reference	CenterPoint Energy	Houston Electric	CERC
†31.2.2		Rule 13a-14(a)/15d-14(a) Certification of Christopher A. Foster					X	
†31.2.3		Rule 13a-14(a)/15d-14(a) Certification of Christopher A. Foster						X
†32.1.1	—	Section 1350 Certification of Jason P. Wells				X		
†32.1.2	—	Section 1350 Certification of Darin M. Carroll					X	
†32.1.3	—	Section 1350 Certification of Richard C. Leger						X
†32.2.1	—	Section 1350 Certification of Christopher A. Foster				X		
†32.2.2	—	Section 1350 Certification of Christopher A. Foster					X	
†32.2.3	—	Section 1350 Certification of Christopher A. Foster						X
97.1	—	CenterPoint Energy's Executive Officer Recovery Policy	CenterPoint Energy's 10-K for the year ended December 31, 2023	1-31447	97.1	X		
97.2	—	Houston Electric's Amended and Restated Executive Officer Recovery Policy	CenterPoint Energy's 10-K for the year ended December 31, 2023	1-31447	97.2		X	
97.3	—	CERC's Amended and Restated Executive Officer Recovery Policy	CenterPoint Energy's 10-K for the year ended December 31, 2023	1-31447	97.3			X
†101.INS	—	Inline XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document				X	X	X
†101.SCH	—	Inline XBRL Taxonomy Extension Schema Document				X	X	X
†101.CAL	—	Inline XBRL Taxonomy Extension Calculation Linkbase Document				X	X	X
†101.DEF	—	Inline XBRL Taxonomy Extension Definition Linkbase Document				X	X	X
†101.LAB	—	Inline XBRL Taxonomy Extension Labels Linkbase Document				X	X	X
†101.PRE	—	Inline XBRL Taxonomy Extension Presentation Linkbase Document				X	X	X
†104	—	Cover Page Interactive Data File (formatted as Inline XBRL and contained in Exhibit 101)				X	X	X

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrants have duly caused this report to be signed on their behalf by the undersigned, thereunto duly authorized, in the City of Houston, the State of Texas, on the 20th day of February, 2025.

CENTERPOINT ENERGY, INC.
(Registrant)

By: /s/ JASON P. WELLS
Jason P. Wells
President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on February 20, 2025.

Signature	Title
/s/ JASON P. WELLS Jason P. Wells	President, Chief Executive Officer and Director (Principal Executive Officer and Director)
/s/ CHRISTOPHER A. FOSTER Christopher A. Foster	Executive Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ KRISTIE L. COLVIN Kristie L. Colvin	Senior Vice President and Chief Accounting Officer (Duly Authorized Officer and Principal Accounting Officer)
/s/ WENDOLYNN MONTOYA CLOONAN Wendolynn Montoya Cloonan	Director
/s/ EARL M. CUMMINGS Earl M. Cummings	Director
/s/ BARBARA J. DUGANIER Barbara J. Duganier	Director
/s/ CHRISTOPHER H. FRANKLIN Christopher H. Franklin	Director
/s/ RAQUELLE W. LEWIS Raquelle W. Lewis	Director
/s/ THADDEUS J. MALIK Thaddeus J. Malik	Director
/s/ THEODORE F. POUND Theodore F. Pound	Director
/s/ RICKY A. RAVEN Ricky A. Raven	Director
/s/ DEAN L. SEAVERS Dean L. Seavers	Director
/s/ PHILLIP R. SMITH Phillip R. Smith	Director

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
(Registrant)

By: /s/ DARIN M. Carroll
Darin M. Carroll
President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on February 20, 2025.

Signature	Title
/s/ DARIN M. Carroll Darin M. Carroll	President, and Chief Executive Officer (Principal Executive Officer)
/s/ CHRISTOPHER A. FOSTER Christopher A. Foster	Executive Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ KRISTIE L. COLVIN Kristie L. Colvin	Senior Vice President and Chief Accounting Officer (Duly Authorized Officer and Principal Accounting Officer)

CENTERPOINT ENERGY RESOURCES CORP.
(Registrant)

By: /s/ RICHARD C. LEGER
Richard C. Leger
President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities indicated on February 20, 2025.

Signature	Title
/s/ RICHARD C. LEGER Richard C. Leger	President and Chief Executive Officer (Principal Executive Officer and Director)
/s/ CHRISTOPHER A. FOSTER Christopher A. Foster	Executive Vice President and Chief Financial Officer (Principal Financial Officer)
/s/ KRISTIE L. COLVIN Kristie L. Colvin	Senior Vice President and Chief Accounting Officer (Duly Authorized Officer and Principal Accounting Officer)

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Investor Information

Reconciliation of Consolidated income (loss) available to common shareholders and diluted earnings (loss) per share (GAAP) to non-GAAP income and non-GAAP diluted earnings per share

	Year-to-Date Ended December 31, 2024	
	Dollars in millions	Diluted EPS [1]
Consolidated income (loss) available to common shareholders and diluted EPS	$ 1,019	$ 1.58
ZENS-related mark-to-market (gains) losses:		
Equity securities (net of taxes of $4) [2][3]	(15)	(0.02)
Indexed debt securities (net of taxes of $3) [2]	11	0.01
Impacts associated with mergers and divestitures (net of taxes of $3) [2][4]	26	0.04
Consolidated on a non-GAAP basis [5]	$ 1,041	$ 1.62

[1] Quarterly diluted EPS on both a GAAP and non-GAAP basis are based on the weighted average number of shares of common stock outstanding during the quarter, and the sum of the quarters may not equal year-to-date diluted EPS.

[2] Taxes are computed based on the impact removing such item would have on tax expense.

[3] Comprised of common stock of AT&T Inc., Charter Communications, Inc., and Warner Bros. Discovery, Inc.

[4] Includes professional fees associated with execution of transactions from the sale of Louisiana and Mississippi LDCs.

[5] The calculation on a per-share basis may not add down due to rounding.

Reconciliation of Consolidated income (loss) available to common shareholders and diluted earnings (loss) per share (GAAP) to non-GAAP income and non-GAAP diluted earnings per share

	Year-to-Date Ended December 31, 2023	
	Dollars in millions	Diluted EPS [1]
Consolidated income (loss) available to common shareholders and diluted EPS	$ 867	$ 1.37
ZENS-related mark-to-market (gains) losses:		
Equity securities (net of taxes of $7) [2][3]	(25)	(0.04)
Indexed debt securities (net of taxes of $6) [2]	21	0.03
Impacts associated with mergers and divestitures (net of taxes of $64) [2][4]	89	0.14
Consolidated on a non-GAAP basis	$ 952	$ 1.50

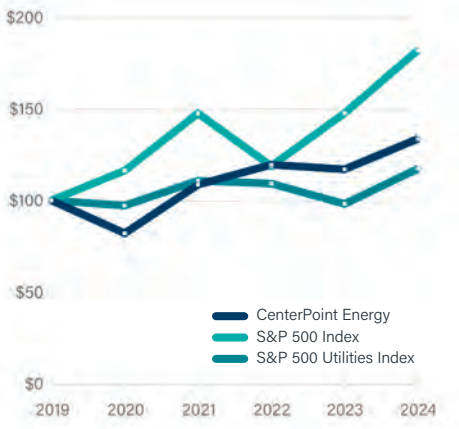
[1] Quarterly diluted EPS on both a GAAP and non-GAAP basis are based on the weighted average number of shares of common stock outstanding during the quarter, and the sum of the quarters may not equal year-to-date diluted EPS.

[2] Taxes are computed based on the impact removing such item would have on tax expense. Taxes related to the operating results of Energy Systems Group, as well as cash taxes payable and other tax impacts related to the sale of Energy Systems Group, are excluded from non-GAAP EPS.

[3] Comprised of common stock of AT&T Inc., Charter Communications, Inc., and Warner Bros. Discovery, Inc.

[4] Includes $4.4 million of pre-tax operating loss related to Energy Systems Group, a divested non-regulated business, as well as the $13 million loss on sale and approximately $2 million of other indirect related transaction costs associated with the divestiture.

Five-Year Cumulative Total Return Comparison for the Fiscal Years Ended December 31 [1][2]



[1] Assumes that the value of the investment in the Common Stock and each index was $100 on December 31, 2019, and that all dividends were reinvested.

[2] Historical stock performance is not necessarily indicative of future stock performance.

Cautionary Statement and Risk Factors

Certain disclosures in this Annual Report may be considered "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995, including statements regarding our resiliency and modernization plans and programs (including the GHRI and Systemwide Resiliency Plan) and the timing and anticipated benefits of such plans and programs, our capital investments (including with respect to incremental capital opportunities and deployment of capital), the timing of, projections for, and anticipated benefits from rate cases for CenterPoint and its subsidiaries (including any settlements thereof), the timing and extent of CenterPoint's recovery (including with regards to its restoration costs for Hurricane Beryl), electric demand growth in our service territories (including our forecasts of, the timing of investments related to, and anticipated benefits of such growth), the timing and extent of anticipated benefits of the announced sale of our Louisiana and Mississippi natural gas local distribution company businesses, future earnings and guidance (including long-term growth rate), the timing and anticipated benefits of our 10-year capital plan, customer charges, future financial performance and results of operations, regulatory actions (including actions allowing requested securitization for severe weather events) and recoverability of capital investments, customer rate affordability, value creation, opportunities and expectations and any other statement that is not historical fact. The "cautionary statement" on page viii and "certain factors affecting future earnings" beginning on page 54 of CenterPoint Energy's Form 10-K for the year ended December 31, 2024, and the disclosure referenced therein, should be read in conjunction with the forward-looking statements. Our business is subject to risk and uncertainty. Please refer to our risk factors beginning on page 18 of our Form 10-K.

Continued on next page

Net Zero Disclaimer

Our Scope 1 greenhouse gas ("GHG") emissions estimates are calculated from GHG emissions that directly come from our operations. Our Scope 2 GHG emissions estimates are calculated from GHG emissions that indirectly come from our energy usage, but because Texas is in an unregulated market, our Scope 2 GHG emissions estimates do not take into account Texas electric transmission and distribution assets in the line loss calculation and exclude GHG emissions related to purchased power between 2024E-2026E. Our Scope 3 GHG emissions estimates are based on the total natural gas supply delivered to residential and commercial customers as reported in the U.S. Energy Information Administration (EIA) Form EIA-176 reports and do not take into account the GHG emissions of transport customers and GHG emissions related to upstream extraction. While we believe that we have a clear path towards achieving our net zero GHG emissions (Scope 1 and certain Scope 2) by 2035 goals and our 20-30% reduction in certain Scope 3 GHG emissions by 2035 as compared to 2021 levels goals, our analysis and plan for execution require us to make a number of assumptions. These goals and underlying assumptions involve risks and uncertainties and are not guarantees. Should one or more of these underlying assumptions require updating, our actual results and ability to achieve our net zero and GHG emissions reduction goals by 2035 could differ materially from our expectations. For more information regarding the assumptions and risks associated with our net zero and GHG emissions reduction goals, see page 30 of CenterPoint Energy's Annual Report on Form 10-K for the year ended December 31, 2024. Please also review the section entitled "Cautionary Statement and Risk Factors" on the previous page.

Use of Non-GAAP Financial Measures

In this Annual Report, CenterPoint Energy presents, based on income available to common shareholders and diluted earnings per share, the following financial measures which are not generally accepted accounting principles ("GAAP") financial measures: non-GAAP income and non-GAAP earnings per share ("non-GAAP EPS"). Generally, a non-GAAP financial measure is a numerical measure of a company's historical or future financial performance that excludes or includes amounts that are not normally excluded or included in the most directly comparable GAAP financial measure.

2023 and 2024 non-GAAP EPS excluded, and 2025 non-GAAP EPS guidance excludes: (a) Earnings or losses from the change in value of ZENS and related securities, and (b) Gain and impact, including related expenses, associated with mergers and divestitures, such as the divestiture of Energy Systems Group, LLC, and the Louisiana and Mississippi gas LDC sales. 2025 non-GAAP EPS guidance also excludes impacts related to temporary emergency electric energy facilities "TEEEF" once they are no longer part of our rate-regulated business. In providing this guidance, CenterPoint Energy does not consider the items noted above and other potential impacts such as changes in accounting standards, impairments or other unusual items, which could have a material impact on GAAP reported results for the applicable guidance period. The 2025 non-GAAP EPS range also considers assumptions for certain significant variables that may impact earnings, such as customer growth and usage including normal weather, throughput, recovery of capital invested, effective tax rates, financing activities and related interest rates, and regulatory and judicial proceedings. To the extent actual results deviate from these assumptions, the 2025 non-GAAP EPS guidance range may not be met, or the projected annual non-GAAP EPS growth rate may change. CenterPoint Energy is unable to present a quantitative reconciliation of forward-looking non-GAAP diluted earnings per share because changes in the value of ZENS and related securities, future impairments, and other unusual items are not estimable and are difficult to predict due to various factors outside of management's control.

This Annual Report contains a reconciliation of income (loss) available to common shareholders and diluted earnings (loss) per share to the basis used in providing guidance.

Management evaluates the Company's financial performance in part based on non-GAAP income and non-GAAP EPS. Management believes that presenting these non-GAAP financial measures enhances an investor's understanding of CenterPoint Energy's overall financial performance by providing them with an additional meaningful and relevant comparison of current and anticipated future results across periods. The adjustments made in these non-GAAP financial measures exclude items that Management believes do not most accurately reflect the Company's fundamental business performance. These excluded items are reflected in the reconciliation tables, where applicable. CenterPoint Energy's non-GAAP income and non-GAAP EPS financial measures should be considered as a supplement to, and not as a substitute for, or superior to, income available to common shareholders and diluted earnings per share, which, respectively, are the most directly comparable GAAP financial measures. These non-GAAP financial measures also may be different than non-GAAP financial measures used by other companies.

CenterPoint® Energy

Annual Meeting

The 2025 Annual Meeting of Shareholders will be held on Wednesday, April 16, 2025, at 8:30 a.m. CT in the CenterPoint Energy Tower auditorium at 1111 Louisiana Street, Houston, TX. Shareholders who held shares of CenterPoint Energy Common Stock at the close of business on February 18, 2025, will receive notice of the meeting and will be eligible to vote.

Auditors

Independent Registered Public Accounting Firm
Deloitte & Touche LLP
Houston, TX

Investor Services

If you have questions about your CenterPoint Energy investor account, please contact our Transfer Agent:
Broadridge Corporate Issuer Solutions, Inc.
P.O. Box 1342
Brentwood, NY 11717
http://shareholder.broadridge.com/cnp
Toll-free: 800-231-6406

Investor Services, online tools and a list of publications can be found on the company's website at Investors.CenterPointEnergy.com.

Investor Services representatives are available from 8 a.m. to 5 p.m. CT, Monday through Friday, to assist with questions about CenterPoint Energy Common Stock or enrollment in the CenterPoint Energy Investor's Choice Plan.

The Investor's Choice Plan provides easy, inexpensive investment options, including direct purchase and sale of CenterPoint Energy Common Stock; dividend reinvestment; statement-based accounting; and monthly or quarterly automatic investing by electronic transfer. You can become a registered CenterPoint Energy shareholder by making an initial investment of at least $250 through the Investor's Choice Plan.

Information Requests

Download or call 855-305-0857 toll-free for additional copies of our:
2024 Annual Report and Form 10-K
2025 Proxy Statement

Dividend Payments

Common Stock dividends are generally paid quarterly in March, June, September and December. Dividends are subject to declaration by the Board of Directors, which establishes the amount of each quarterly Common Stock dividend and fixes the record and payment dates.

Institutional Investors

Security analysts and other investment professionals should contact Jackie Richert, Senior Vice President, Corporate Planning, Investor Relations & Treasury, at 713-207-6500.

Stock Listing

CenterPoint Energy, Inc. Common Stock is traded under the symbol CNP on the New York Stock Exchange and NYSE Chicago.

Company Headquarters Street Address

CenterPoint Energy, Inc.
1111 Louisiana Street
Houston, TX 77002

Mailing Address

P.O. Box 4567
Houston, TX 77210-4567
Telephone: 713-207-1111
CenterPointEnergy.com

Company Leadership

Senior Leaders



Jason P. Wells

President & Chief Executive Officer



Christopher A. Foster

Executive Vice President & Chief Financial Officer



Monica Karuturi

Executive Vice President & General Counsel



Jason M. Ryan

Executive Vice President, Regulatory Services & Government Affairs

Board of Directors



Phillip R. Smith



Wendy Montoya Cloonan



Earl M. Cummings



Barbara J. Duganier



Christopher H. Franklin



Raquelle W. Lewis



Thaddeus J. Malik



Theodore F. Pound



Ricky A. Raven



Dean L. Seavers



Jason P. Wells

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www.youtube.com/CenterPointEnergyvid

CenterPoint® Energy

Energy for what matters most™

Company Headquarters
1111 Louisiana Street
Houston, TX 77002

CenterPointEnergy.com

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

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

Exhibit 80
CenterPoint Indiana 2025 IRP Summary



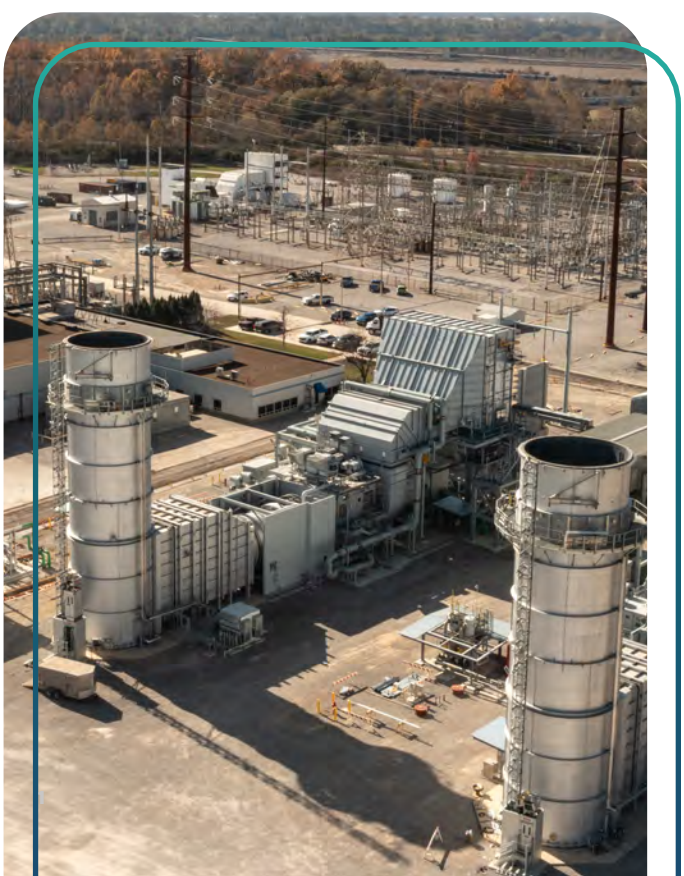
Executive Summary

(Non-Technical Summary)

Introduction

Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South's ("CEI South"/"CEIS") 2025 Integrated Resource Plan ("IRP") is the culmination of an extensive analysis of CEI South's optimal resources for ensuring the availability of electricity to its retail electric customers over a 20-year period at a low cost with consideration for future cost risks. CEI South has adhered to the requirements of the Indiana Utility Regulatory Commission ("IURC" or "Commission") and the guidance provided in the Commission's orders related to past Preferred Portfolios described in CEI South's previous IRPs both in the preparation of this IRP and the planning process that preceded the report.

CEI South conducts the IRP process every three years and each IRP, necessarily, builds on the IRP and the generation resource investments that have come before. CEI South's 2022/2023 IRP identified a Preferred Portfolio that included a generation transition with the conversion of F.B. Culley 3 from coal to natural gas, along with Demand Side Management ("DSM"), wind, and solar resources. CEI South began implementing the 2022/2023 IRP by filing two cases for which CEI South sought and received approval for (1) two signed purchase power agreements ("PPA") for wind facilities totaling 317 MWs, the Galesburg Wind Project and the Salt Creek Wind Project; and (2) approval for the 2025-2027 DSM Plan. Each of these filings were consistent with the 2022/2023 IRP, and as noted below, the IRP affirms the direction taken by CEI South. These renewable resources still qualify for Federal incentives, which dramatically lowered their cost relative to what could be acquired in the future, post elimination of Inflation Reduction Act ("IRA") tax incentives for wind and solar resources.



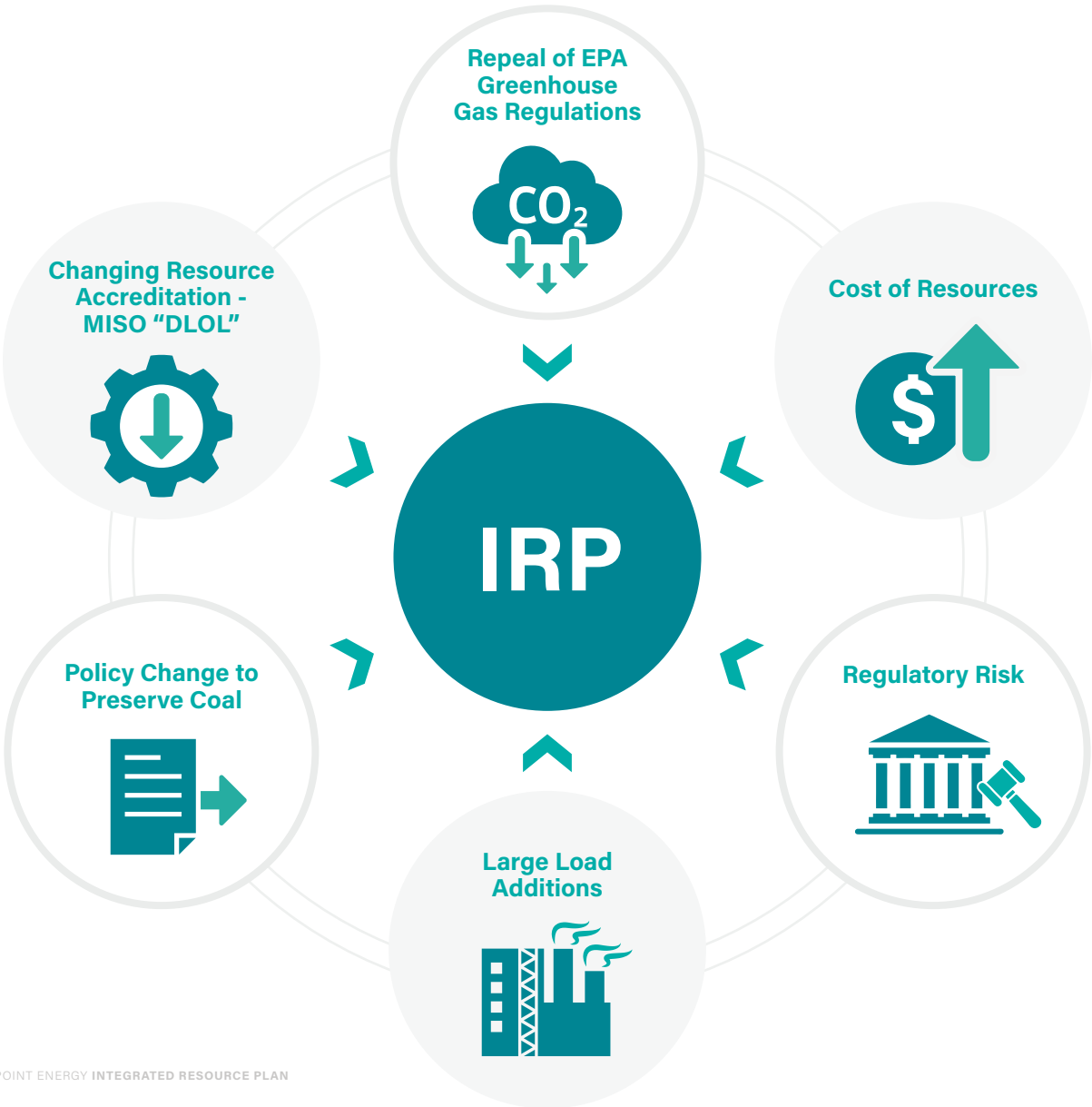
Now in 2025, during this time of unprecedented uncertainty across multiple fronts, the 2025 IRP analysis and its conclusions highlight the prudent decision for CEI South to reevaluate the timing of its generation fleet transition. Amid this time of evolving risk, and following our most recent rate case, there has been feedback from our customers and their advocates to keep bills more affordable. The IRP public meetings allowed us to listen to stakeholders and explain the uncertainty facing the industry.

Therefore, CEI South is reevaluating the timing of its transition to new or upgraded equipment in the near-term with a **focus toward rate stability and system reliability**.



The world looks very different than it did twelve months ago, when this IRP process began. The current pace and amount of change creates a variety of risks that, when weighed together, supports CEI South's decision to reevaluate the generation transition. The figure below summarizes current uncertainties.

Current Uncertainties





In 2023, CEI South filed its first electric base rate case in nearly 14 years. Ultimately, CEI South was approved to recover an additional $80 million from customers to continue to **safely and reliably deliver electricity** to their homes and businesses. While the energy transition CEI South set forth in prior IRPs was more affordable in the long run than continuing to operate its coal units, approximately 80% of the approved rate case increase was related to replacing A.B. Brown coal units 1 & 2 with 191 MW Posey Solar (~$385 million) and 460 MW natural gas combustion turbines (~$287 million). A.B. Brown's aging environmental equipment was required to be updated and replaced at a similar cost by 2024; this fact helps to illustrate the importance of strongly considering near-term affordability within the context of the IRP.

In this dynamic environment, CEI South has remained nimble to allow it to provide affordable and reliable service for its customers. Since the last IRPs were filed, there have been significant challenges in moving forward with key pieces of the last two IRPs' Preferred Portfolios. Several solar projects were terminated due to shifting market dynamics and substantial delays in commercial operation dates—one exceeding four years, with others averaging more than three. These market changes and delays drove project costs beyond the levels approved by the Commission and above what CEI South believed economical for its customers.

As such, the Crosstrack Solar Project, a 130 MW Build Transfer Agreement ("BTA") approved in Cause No. 45754, was terminated on March 15, 2024. Subsequently, two solar PPAs were also canceled on July 1, 2025, due to cost increases beyond the approved agreements, the 100 MW Warrick County Solar Project and the 185 MW Vermillion Solar Project, both approved in Cause No. 45839. Similarly, a 200 MW wind BTA also had upward pricing pressure. After years of negotiation and a re-evaluation of this project, CEI South opted, in this IRP, to abandon this project in an effort to avoid additional customer bill impact.

Also, in early 2025, CEI South announced that it paused the plan to convert F.B. Culley 3 to natural gas, to be re-evaluated in this IRP. Within this analysis, CEI South utilized more refined cost estimates and assumptions based on our preparation to convert the unit. This decision to pause the conversion was not taken lightly and was the direct result of near-term affordability concerns raised by the community, along with the current uncertainties listed in the previous figure.

Although the previous IRP projected long-term cost savings, CEI South estimates that implementing all proposed projects as planned would have resulted in a near-term bill increase of approximately $18 per month over the next few years. CEI South also heard some stakeholders express interest in re-evaluating the

decision to convert F.B. Culley 3 within the context of the transparent IRP process, particularly given the near-term uncertainty driven by changes in the Federal and State administrations. CEI South's decision to reevaluate this path forward proved to be prudent. Under today's market conditions, (elimination of future Federal tax incentives for renewables, declining accreditation from MISO for renewables, increased price pressure on resources based on tariffs/ongoing supply chain issues), converting F.B. Culley 3 to natural gas by 2030 with renewables is projected to be the second highest cost portfolio evaluated, 17% higher than the lowest cost portfolio examined and 14% higher than the Preferred Portfolio.

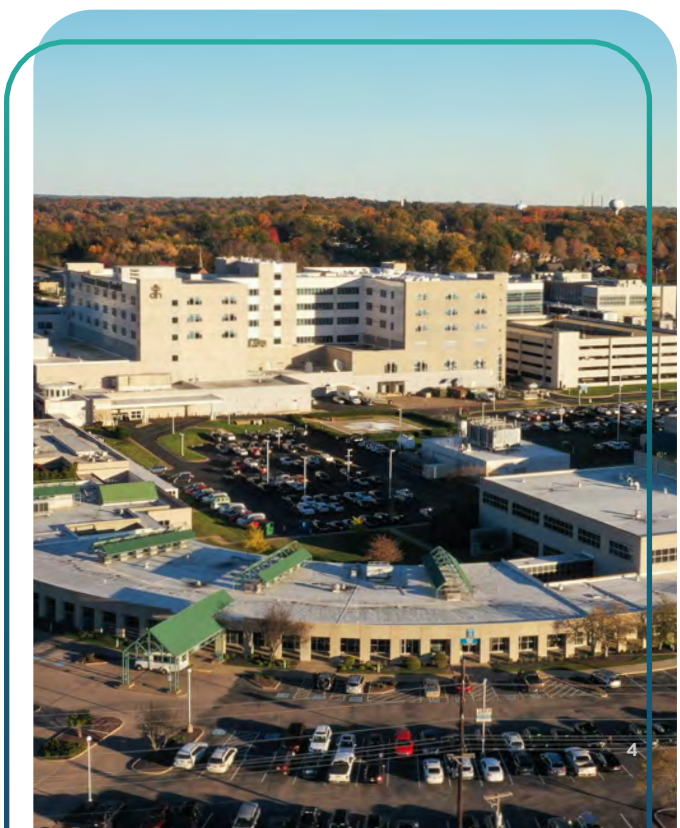
CEI South began its 2025 IRP process in early 2025 to explore new and existing supply-side and demand side resource options to reliably serve CEI South customers over the next 20 years. The Company's exploration included significant input and dialogue with stakeholders. While starting with our 2022/2023 IRP framework as a basis for the 2025 analysis, CEI South has enhanced its process and analysis in several ways. These enhancements include, but are not limited to, the following:

- expanded sensitivity analysis (distributed solar incentive, large load additions, Demand Response term, etc.);
- increased collaboration with transmission and distribution planning;
- enhanced transmission analysis, unserved energy, capacity risk, etc.;
- inclusion of an expected data release schedule;
- five pillars focused score card with an expanded view of affordability; and
- refreshed IRP layout with enhanced description of analysis and results.

Over the last year, CEI South has participated in active discussions with several large load customers, and there was considerable stakeholder interest in understanding how CEI South would serve a large load addition. In order to maintain maximum flexibility, CEI South responded by including large load sensitivities and adding an alternate reference case to its analysis.

To maintain maximum flexibility and agility in these uncertain times, CEI South has selected both a **Preferred** and an **Alternate Preferred Portfolio**.

The Preferred Portfolio assumes the status quo for our territory. The Alternate Preferred Portfolio was developed should CEI South be in a position to provide power to a large load addition.





The alternate reference case maintains reference case market conditions but includes a potential large load addition that grows by 250 MWs per year, topping out at 1.5 GWs above CEI South's current retail load. This large load profile is indicative of ongoing discussions/ negotiations with prospective customers. Potential large load customers require utilities to be able to serve their needs quickly, or they will take their economic development, supporting jobs and the tax base for the community, elsewhere.

CEI South plays a proactive role in **advancing economic development** across southwestern Indiana. By developing an Alternative Preferred Portfolio, the company enhances its agility **to better serve and support the region's evolving needs**.

With the need to provide reliable, stable, resilient, affordable, and sustainable energy to our customers, both Preferred Portfolios call for the conversion of A.B. Brown natural gas Combustion Turbine ("CT"), units 5 and 6, to an efficient Combined Cycle Gas Turbine ("CCGT"). The Preferred Portfolio provides customers with near and long-term rate stability and pushes this decision out to future IRPs until there is more clarity on the future while the Alternate Preferred Portfolio moves forward with the conversion by 2030. In either case, the decision on F.B. Culley 3's replacement will be decided in a future IRP. Both portfolios include the remaining solar and wind energy resources—secured prior to this IRP—at significantly lower costs compared to future renewable projects that may not benefit from near- to midterm Federal tax incentives. Both portfolios also include battery storage to replace CEI South's smallest and most inefficient coal unit, F.B. Culley 2. This allows time for CEI South to further evaluate the economics of this option relative to purchasing required capacity to maintain reliability. Finally, both include continued investment in energy efficiency and demand response resources.

The company has signed a contract with a demand response ("DR") aggregator for commercial and industrial DR by 2026. CEI South is also nearing the beginning of a pilot which was approved in its recent rate case to explore time-based rates. The Preferred Portfolio includes indicative DR amounts for IRP planning purposes.

Preferred Portfolio



CEI South's Preferred Portfolio takes a more gradual approach to its generation transition, providing time for greater clarity amid today's unprecedented uncertainty. This approach also allows time for transmission system upgrades through CEI South's current TDSIC plan and the MISO's Long-Range Transmission Plan ("LRTP") Tranche 2.1 projects, which support enhanced reliability and resilience.

The Preferred Portfolio provides for **maximum flexibility** to pivot should the future turn out differently than expected.

This is crucial in this current environment, where developers are less willing to share in cost risk which drives generation project costs higher for utility customers, with uncertainty around how much accreditation resources will receive from MISO to meet reliability requirements, or the direction of future greenhouse gas regulations.

In the short term, the plan maintains the F.B. Culley 2 interconnection, with possible 90 MW battery storage reuse and continues the demand side management programs. In the long-term and to be reevaluated in a future IRP, the plan calls for the conversion of A.B. Brown units 5 & 6 gas turbines to an efficient CCGT unit in 2034 to replace F.B. Culley 3 by 2035. The plan also calls for 50 MWs of battery storage in 2040 and 2045 to meet its planning reserve margin requirements.



Preferred Portfolio: **How Did We Get Here**

While current modeling suggests that replacement of F.B. Culley 3 coal with conversion of CEI South's two new CTs to a CCGT by 2030 could save customers money in the long run, locking in this option for CEI South's retail customers could increase bills in the near-term, increase risk, and reduce future flexibility. The conversion of these units would cost approximately $1 billion dollars or more and would likely be included in customer rates by 2030, costing customers up to $21 [1] more per month on average in the near term compared to the Preferred Portfolio which delays this decision. Affordability, one of the five pillars, is top of mind for CEI South and its customers following our recent rate case and has also been prominent within IRP stakeholder comments.

By slowing down the generation transition, customers should benefit from rate stability while preserving the flexibility—a critical capability in today's landscape—for CEI South to reevaluate F.B. Culley 3's fate in a future IRP. For example, in its previous IRP, CEI South had planned to convert F.B. Culley 3 to natural gas by 2027 with a continued renewables build out. However, just three years later, shifting external factors—such as reduced MISO accreditation for renewables, increased costs driven by market uncertainty, and diminished federal support following the rollback of key IRA tax incentives—have made this a more costly strategy relative to alternatives (14-17% higher).

Preferred Portfolio: **Overview**

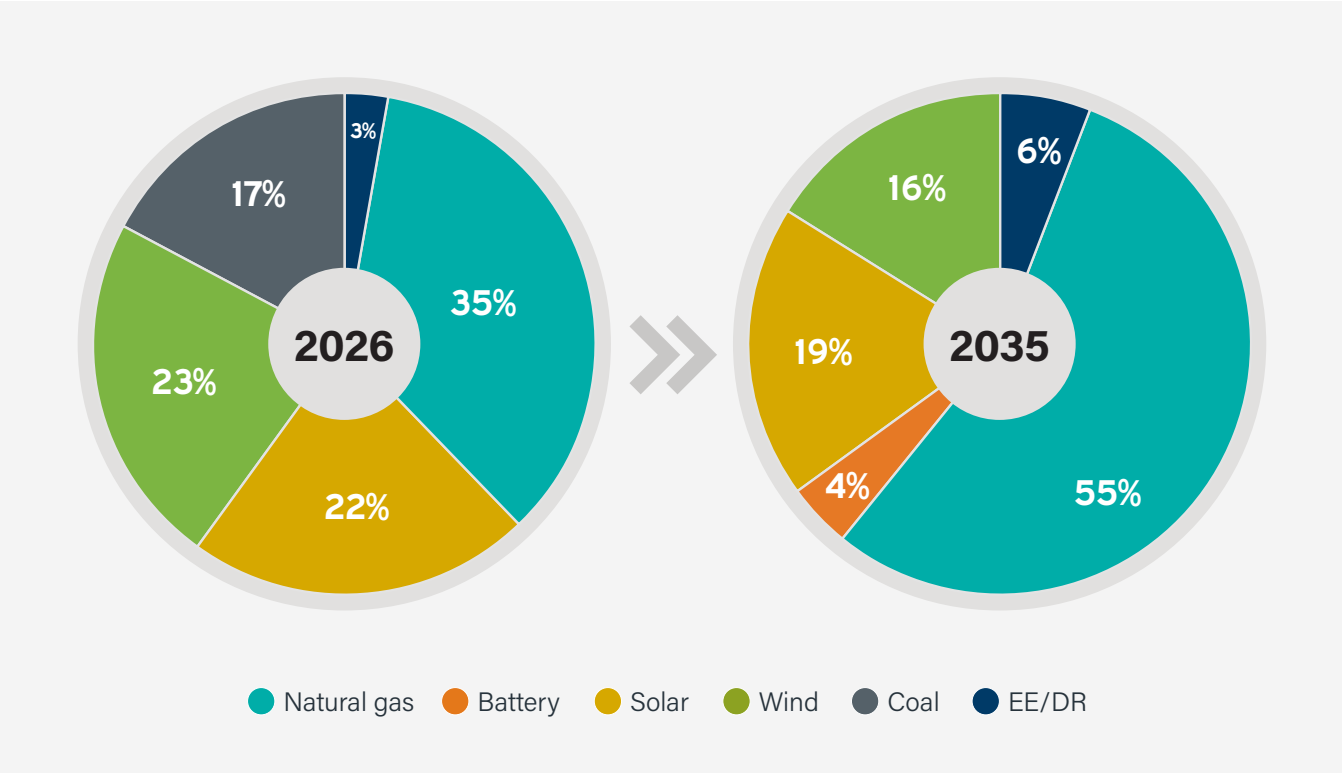
Between now and 2034, the Preferred Portfolio preserves the option to replace F.B. Culley 2 coal plant when it is suspended at the end of 2025 with a 90 MW battery storage unit by the end of 2028. CEI South will conduct another Request for Proposal ("RFP") to determine if the cost of this project has escalated from what was bid in the All-Source RFP and compare the cost to required capacity purchases. Based on the All-Source RFP, the cost of this battery is nearly identical to purchasing an equivalent amount of capacity on the market. Locking in capacity with a battery should help stabilize bills versus purchasing from a volatile capacity market that is expected to see rising prices as MISO's reserve margin continues to decline. It also helps maintain reliability with an on-system resource to help supply stored energy when it is needed most.

The Preferred Portfolio secures cost savings from wind and solar resources identified and acquired through previous IRPs, ahead of the repeal of IRA renewable energy tax incentives under the One Big Beautiful Bill Act ("OBBBA"). It also maintains operational flexibility by allowing F.B. Culley 3 to continue to run on coal, allowing time to reevaluate if conversion to natural gas or earlier retirement makes sense in a future IRP.

[1] *Not including expected offsetting sales revenues*

Preferred Portfolio: **Key Considerations**

CEI South's preferred resource plan reduces risk through continued diversification, lowers the cost to serve load over the next 20 years, and provides flexibility to evaluate and respond to future needs through subsequent IRPs.



The Preferred Portfolio has several advantages, including:

1. Among the least cost options, within **3% of the lowest cost portfolio** in the long term.
2. Provides near-term rate stability for **customer affordability** by delaying large capital investment.
3. Provides **affordable**, **reliable energy** with a well-balanced mix of **sustainable energy resources** and continued focus on demand side resources.
4. F.B. Culley 2 battery storage **enables avoidance of certain required capacity purchases**.



5. **Maximizes flexibility** to navigate unprecedented uncertainty; **minimizes risk**.

   - Delaying large capital investment also mitigates cost risk, as we live in very uncertain times. Current uncertainty is driving near-term price increases for various resources. It also helps reduce long-term price risk by allowing more time to better understand the direction of Environmental Protection Agency ("EPA") greenhouse gas regulations. Over the last 16 years environmental regulations have flexed and retracted with each administration. It is possible that in the next administration an aggressive greenhouse gas regulation could materialize which could throttle how much an efficient combined cycle gas unit may run, or a more stringent environmental regulatory requirement is finalized that would significantly increase operating costs for a fossil-fuel fired generation unit.

   - Provides flexibility under a wide range of potential future legislative, regulatory, and market conditions. Maximum flexibility is important as demonstrated by the massive amount of change that has been experienced over the last decade. By proactively canceling high-cost renewable projects and securing affordable wind power purchase agreements, CEI South has taken decisive action to avoid increasing customer expenses. This forward-thinking strategy also strengthens CEI South's position ahead of MISO's upcoming accreditation reforms—reforms that are expected to significantly reduce the reliability value of certain resources, particularly solar. Additionally, pausing the conversion of F.B. Culley 3 and reevaluating under current market conditions preserves future flexibility at a lower near and long-term cost to our customers.

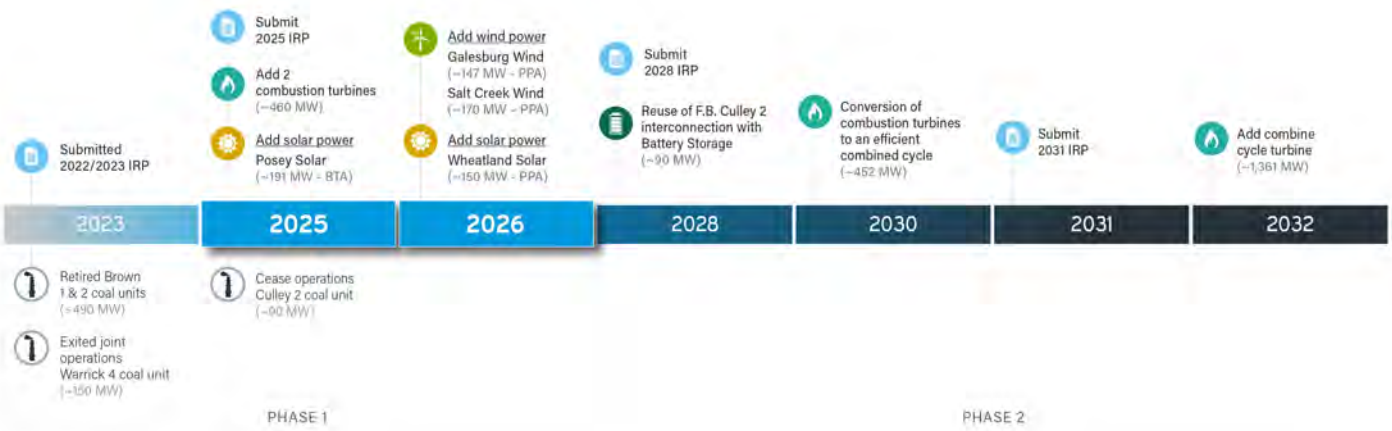
6. **Preserves tax base and jobs in Warrick County.** The replacement of F.B. Culley 2 with a battery storage system provides economic benefit to the community, whereas purchasing this needed capacity from the market does not. It is the equivalent of renting a home vs buying. Allowing F.B. Culley 3 to continue running in the near-term preserves tax base, benefiting the county while it continues to depreciate; it also maintains jobs associated with coal handling. Additionally, the facility uses Indiana-mined coal, preserving mining jobs and supporting the state's economy.

7. Maintains a base load generator on the east side of our system, providing **reliable**, **stable**, and **resilient power**.

   F.B. Culley Unit 3 continues to deliver essential voltage support to our community, providing valuable time for needed transmission expansion and offering flexibility as we await greater clarity on the future of nearby generation facilities that currently play a key role in grid stability.

8. Provides **flexibility** to serve a large load addition, should an **economic development** project materialize (See Alternate Preferred Portfolio).

Alternate Preferred Portfolio



The following Alternate Preferred Portfolio summary includes the process to identify the portfolio as well as an explanation of the planning process, all while focusing on CEI South's operations.

To maintain flexibility and stay nimble for potential economic development opportunities for southwestern Indiana, CEI South chose an **Alternate Preferred Portfolio** for a large load addition.

A large load addition scenario was created, starting at 250 MW and scaling up to 1,500 MWs in the early 2030s. Conversion of the new A.B. Brown CTs to a CCGT and F.B. Culley 2 battery storage become the most affordable options in the near-term to support the ramp. The Alternate Preferred Portfolio utilizes the interconnection at F.B. Culley 2 for a 90 MW battery storage unit by 2028 and continues demand side management programs.

Additionally, the plan calls for the conversion of A.B. Brown units 5 & 6 gas turbines to an efficient CCGT unit by 2030, continues F.B. Culley 3 on coal, and builds a large natural gas combined cycle unit by 2032 to support the large load addition. This build out is paired with near-term reliance on the market and aligns with system capabilities.

Alternate Preferred Portfolio: **How Did We Get Here**

Per stakeholder feedback, CEI South evaluated the potential for a large load addition that would scale over time. This scenario complements the multiple large load sensitivities conducted during the IRP and reflects insights gained from CEI South's ongoing conversations over the past several years with prospective customers across a range of industries. Commonly, CEI South is asked to determine how fast the system can be ready to accommodate a potential customer's business plan. Timelines have been compressed from what was considered normal in the past. These requests require CEI South's generation planning team to work closely with its transmission planning team. This scenario incorporates feedback from both teams, along with expert third party consultants to evaluate what is possible.



Alternate Preferred Portfolio: **Overview**

In the alternate reference case, all market conditions remain the same as reference case conditions, but load is increased by 250 MWs per year until the cumulative load reaches 1,500 MWs in the early 2030s. Load evaluations from prospective customers of this size were extremely uncommon for economic development projects in the past but are now approaching routine. CEI South selected the optimized, least cost model results as the Alternate Preferred Portfolio.

By including an Alternate Preferred Portfolio, CEI South is preserving necessary flexibility to quickly pivot, keeping southwestern Indiana competitive for economic development and growth. The Alternate Preferred Portfolio adds tax base and jobs to the community, not only from the prospective customer facility, but also from the infrastructure needed to support it. CEI South's analysis shows that generation near the site of the load is necessary to provide stability and avoid a large transmission outlay.

Alternate Preferred Portfolio: **Key Considerations**

The Alternate Preferred Portfolio:

- Preserves maximum future flexibility, keeping southwestern Indiana competitive for economic development and growth (Speed to market is important for most prospective customers),
- Adds tax base and jobs in our community, which helps all customers thrive,
- Aligns with Federal and State goals,
- Utilizes F.B. Culley 3 until replacement/conversion to natural gas is decided, and
- Adds efficient on-system base load generation for **reliability**, **stability** and **resilience**.

CEI South will continue to have ongoing conversations with prospective customers. At this point, no contract has been signed. As we prepare for this potential, CEI South will continue to evaluate possible timelines and costs necessary to serve. While the Alternate Preferred Portfolio provides a possible path, the resource mix to serve will be heavily influenced by a potential customer's need for low-cost power, along with other criteria important to the prospective customer. As such, CEI South modeled alternatives to aid in these conversations. CEI South will work to prioritize affordability for its existing customers and minimize future cost risk should conversations turn into negotiations/contracts.

CenterPoint Energy Overview

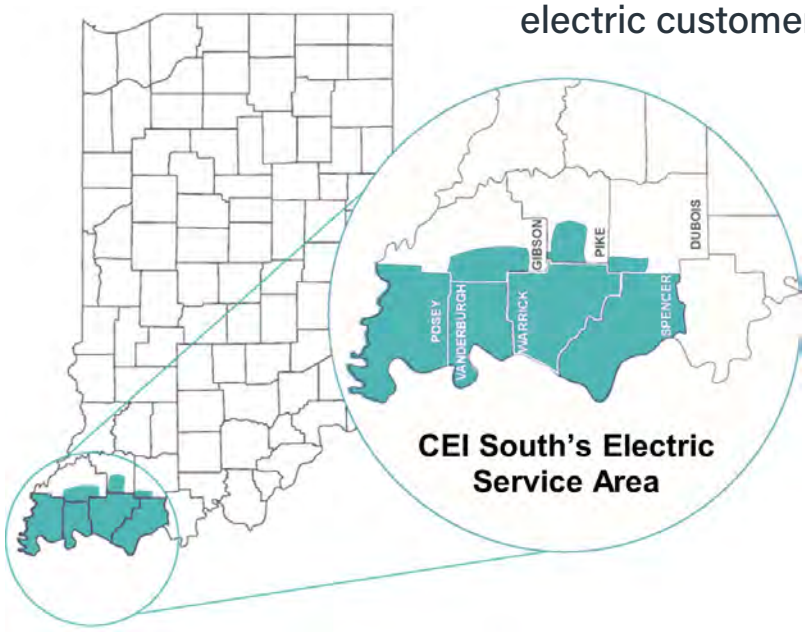
Provides energy delivery services to more than

150,000

electric customers

CEI South provides energy delivery services to more than 150,000 electric customers located near Evansville in southwestern Indiana. In 2024, approximately 45% of electric sales were made to large (primarily industrial) customers, 30% were made to residential customers, and 25% were made to small commercial customers.

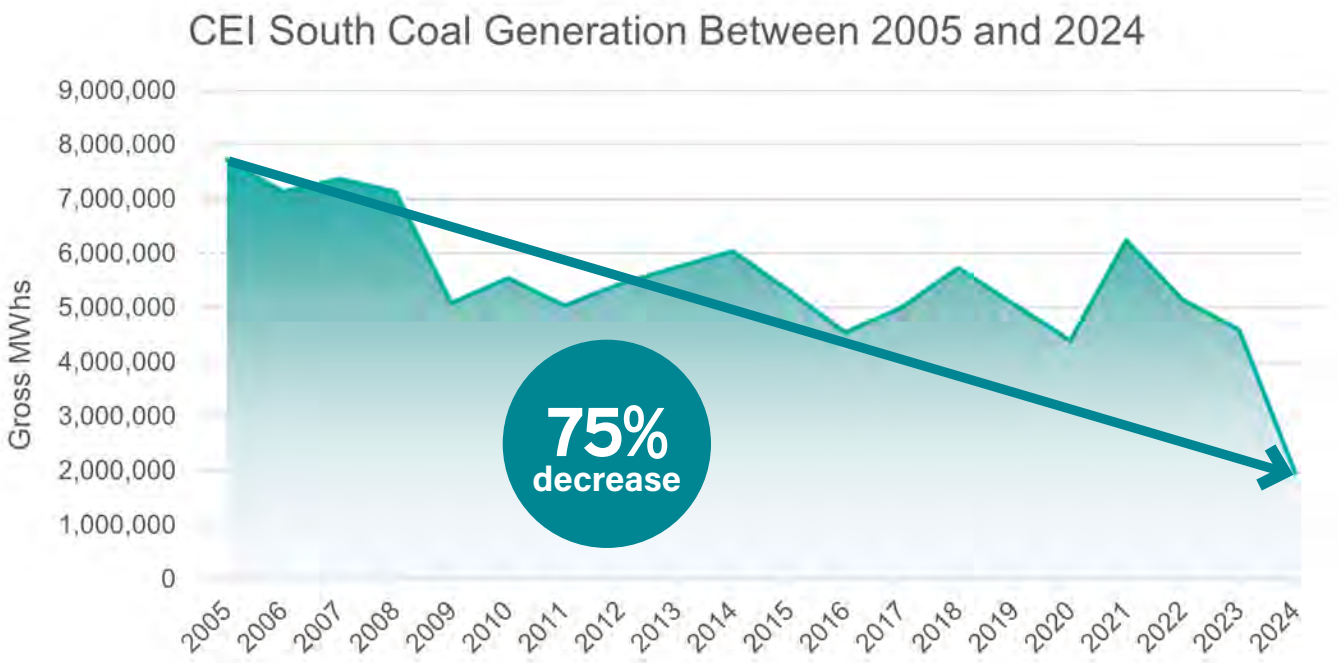
The table below shows CEI South generating units. Note that CEI South also offers customers energy efficiency programs to help lower customer energy usage and bills.



Unit [2]	Installed capacity ICAP (MW)	Primary Fuel	Unit in Service	Unit Retirement Date/Expiration	Unit Age	Coal Unit Environmental Controls [3]
F.B. Culley 2	90	Coal	1966	2025	59	Yes
F.B. Culley 3	270	Coal	1973	N/A	52	Yes
A.B. Brown 3	80	Gas	1991	N/A	34	
A.B. Brown 4	80	Gas	2002	N/A	23	
A.B. Brown 5	230	Gas	2025	N/A	<1	
A.B. Brown 6	230	Gas	2025	N/A	<1	
Blackfoot	3	Renewable Gas	2009	N/A	16	
Fowler Ridge	50	Wind PPA	2010	2029	15	
Benton County	30	Wind PPA	2007	2028	18	
Galesburg	147	Wind PPA	2026	N/A	N/A	
Salt Creek	170	Wind PPA	2026	N/A	N/A	
Troy	50	Solar	2021	N/A	4	
Posey	191	Solar	2025	N/A	<1	
Wheatland	150	Solar PPA	2026	N/A	N/A	
Volkman Rd	2	DG Solar + battery	2018	N/A	7	
Oakhill	2	DG Solar	2018	N/A	7	
Post House	<1	DG Solar	2020	N/A	5	

[2] CEI South has a 1.5% ownership share of Ohio Valley Electric Corporation ("OVEC") which equates to approximately 32 MW.
[3] Both Coal units are controlled for Sulfur Dioxide ("SO2"), Nitrogen Oxide ("NOx"), Particulate Matter (dust), and Mercury. F.B. Culley 3 is controlled for Sulfur Trioxide ("SO3") and Sulfuric Acid ("H2S04").

CEI South has largely moved away from coal, with the retirement of A.B. Brown units 1 & 2, exiting the joint operating agreement for Warrick 4, and the planned suspension of F.B. Culley 2 at the end of 2025.



These resources have been replaced with a diverse mix of wind, solar, energy efficiency, demand response, and gas resources. The current analysis demonstrates that customers receive a better balance of near-term and long-term affordability and reliability by continuing to evaluate the opportunity to replace CEI South's smallest and least efficient coal unit, F.B. Culley 2, with battery energy storage while deferring a decision on replacement of CEI South's last remaining coal unit that it operates, F.B. Culley 3, to a future IRP.

Integrated Resource Plan

Every three years CEI South submits an IRP to the IURC as required. The IRP describes the analysis process used to evaluate the optimal mix of generation, storage, energy efficiency, and demand response resources (resource portfolio) to meet customers' needs for reliable, resilient, stable, affordable, and environmentally sustainable power ("the five pillars") over the next 20 years. The IRP helps set the direction for future generation and energy efficiency options. Future analysis, filings and subsequent approvals from the IURC are needed to implement selection of new resources.

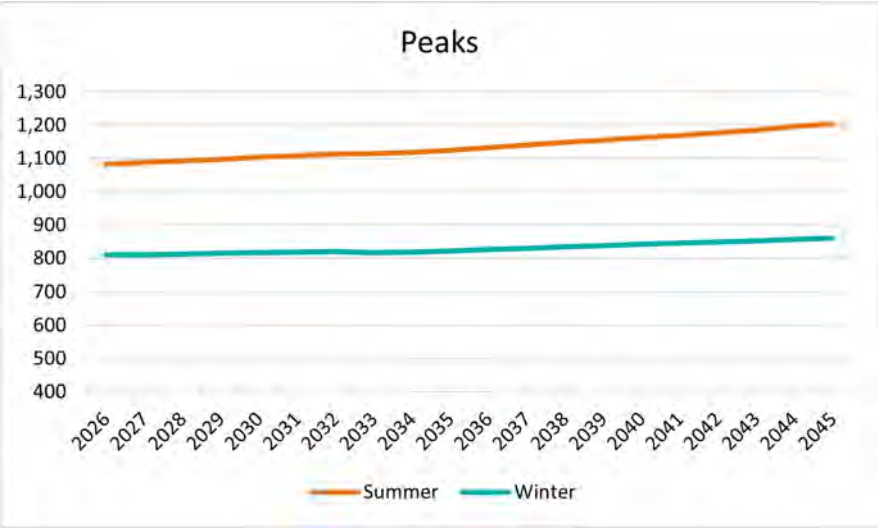
CEI South utilized direct feedback on analysis methodology, analysis inputs, and evaluation criteria from stakeholders, including but not limited to CEI South residential, commercial and industrial customers, regulators, elected officials, customer advocacy groups, trade associations and environmental advocacy groups. CEI South placed considerable emphasis on the five pillars, rate stability, risk, and resource diversity. The IRP process continues to increase in complexity as MISO continues to implement resource accreditation reforms to maintain reliability of the system that includes increased levels of renewable resources, battery energy storage, and natural gas resources to replace existing coal resources.

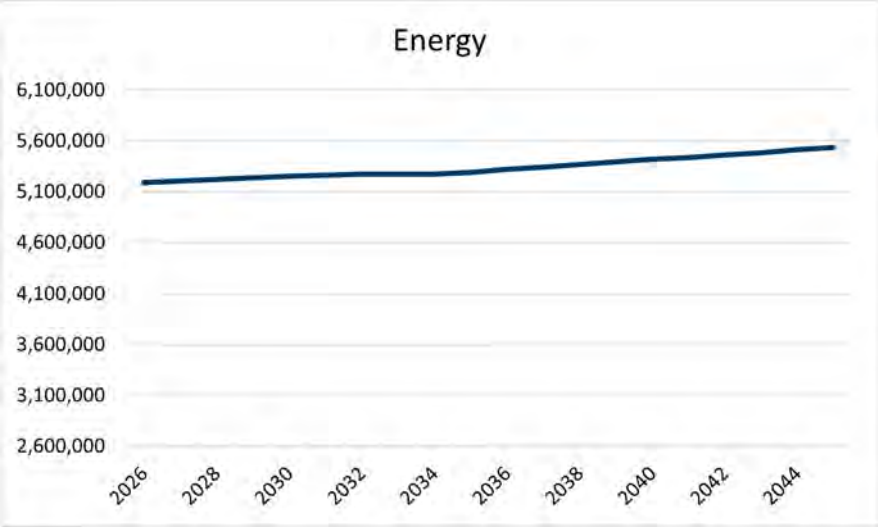
Customer Energy Needs

The IRP begins by evaluating customers' need for electricity over the 20-year planning horizon. CEI South worked with Itron, Inc., a leader in the energy forecasting industry, to develop a forecast of customer energy and demand requirements. Demand is the amount of power being consumed by customers at a given point in time, while energy is the amount of power being consumed over time. Demand is typically measured in Megawatts ("MW"), and energy is typically measured in Megawatt hours ("MWh"). Both are important considerations in the IRP. While CEI South purchases some power from the market, CEI South is required to have enough generation, demand side (energy efficiency and demand response), and storage resources available to meet expected customers' seasonal peak demand plus additional reserve resources to meet MISO's Planning Reserve Margin Requirement ("PRMR") for reliability. Reserve resources are necessary to minimize the chance of rolling black outs; moreover, as a MISO member, CEI South must comply with MISO's evolving rules to maintain reliability.



CEI South must meet customer demand in all hours of the year. This has become more challenging, as the regional resource mix changes towards intermittent (variable) renewable generation. MISO functions as the regional transmission operator for 15 midwestern and southern states, including Indiana (also parts of Canada). MISO evaluates how changes in the future resource mix impact reliability. Recently, they have received FERC approval to update the way resources are accredited to the Direct Loss of Load ("DLOL") methodology beginning in 2028, which is projected to have a substantial impact on solar accreditation in the summer and winter when load is at its highest. CEI South has accounted for this change and worked with stakeholders to develop a reasonable accreditation projection given the best available information. Later in this document it is further explained how MISO continues evaluating measures to help ensure year-round reliability.





CEI South utilizes sophisticated models to help determine energy needs for residential, commercial and large customers. These models include projections for the major drivers of energy consumption, including but not limited to, the economy, appliance efficiency trends, population growth, price of electricity, weather, specific changes in existing large customer demand and customer adoption of solar and electric vehicles.

Overall, customer energy and summer peak demand, excluding energy efficiency, are expected to grow by **0.5% per year**. Winter peak demand grows at a slightly slower pace of **0.3% per year**.

Resource Options Considered

The next step in an IRP is identifying resource options to satisfy customers' anticipated need. Many resources were evaluated to meet customer energy needs over the next 20 years. CEI South considered both new and existing resource options. 1898 & Co., a well-respected engineering firm, conducted an All-Source RFP which generated 95 unique proposals to provide energy and capacity from a wide range of technologies, including: solar, solar + short duration battery storage, standalone short duration battery storage, bio-mass thermal, demand response, and wind. These project bids provided up-to-date, market-based information to inform the analysis. Additionally, CEI South utilized other information sources for long-term costs and operating characteristics for these resources and others over the entire 20-year period. Other options include continuation of existing F.B. Culley 3 coal unit, conversion of F.B. Culley 3 coal unit to natural gas, various other natural gas resources, conversion of A.B. Brown combustion turbines to a Combined Cycle Gas Turbine, hydro, landfill gas, and long-duration batteries.

Every IRP is a snapshot in time producing a direction based on the best-known information. It is helpful to provide some background into significant issues that help shape the IRP analysis, including but not limited to: the accelerated sunset of wind and solar tax incentives from the IRA with the passage of OBBBA, the rise of Artificial Intelligence ("AI") data centers and onshoring of industrial manufacturing driving unprecedented load growth, state and federal executive orders to maintain existing resources, continued increased costs for renewables projects, new technologies, and rapid changes in the MISO market to adapt and help enhance reliability.

- Battery storage
- Coal
- Energy efficiency/ Demand response
- Hydro electric
- Natural gas
- Nuclear
- Wind and solar





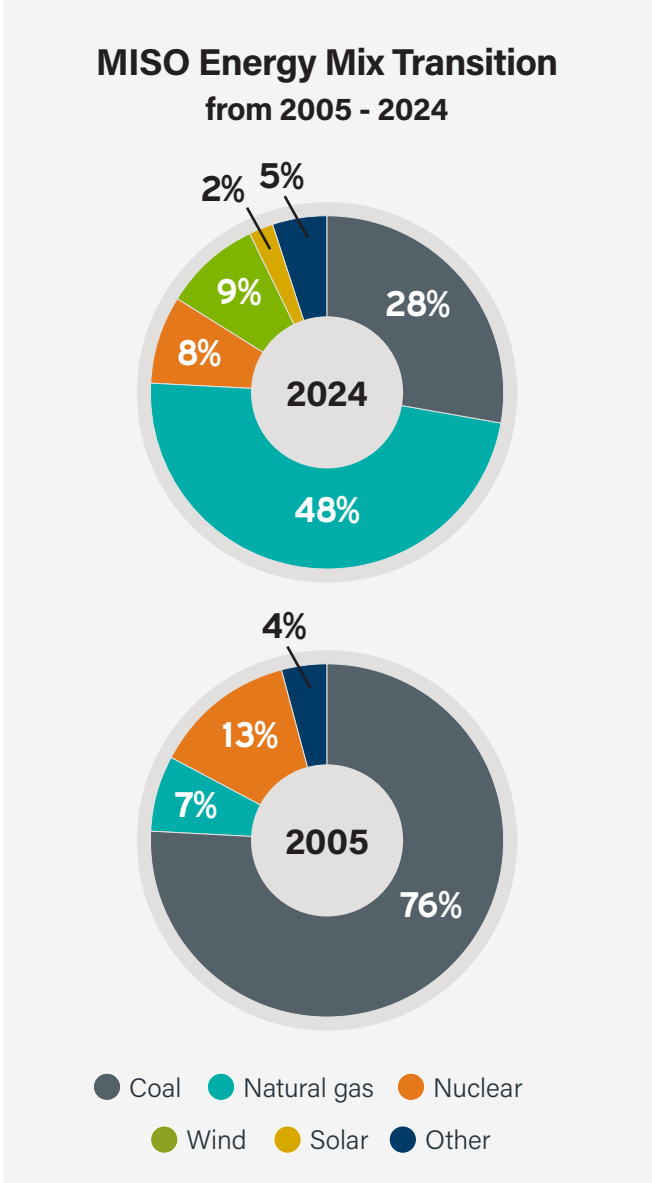


INDUSTRY TRANSITION

The transition to intermittent renewable resources within MISO has continued over the last several years, although at a slower pace. Until the pandemic, renewables costs declined rapidly due to improvements in technology and government incentives. This largely stalled and began an upward climb. Wind and solar resources continue to face increasing price pressure, interconnection delays, and decreasing accreditation from MISO. With the passage of OBBBA, renewable resource tax incentives sunset more quickly than under the IRA placing more pressure on renewable resources.

This comes as load growth to serve data centers supporting AI is projected to ramp very quickly over the next several years. Each data center can use enough energy to power a mid-sized city, and they require power twenty-four hours a day, necessitating dispatchable resources. Additionally, President Trump has made tariffs a core part of his second term. These tariffs are designed to incentivize manufacturing to come back to the United States, thus providing new economic development opportunities, particularly with industries related to national security. For example, his administration has focused on the steel and aluminum industries, which also bring the potential for extremely large loads.

To respond to this challenge, the federal government is working to slash regulations and maintain incentives for baseload (24x7 power) nuclear resources. Additionally, the state of Indiana has responded with incentives for these prospective customers and also with economic development incentives aimed at spurring development in small modular nuclear resources that can provide power intense data centers and large industrial facilities with zero carbon emitting resources, the first of which, in Indiana, is likely to come on-line in the early to mid-2030s.



In the near-term, gas resources are seeing unprecedented demand from utilities to meet increasing near-term load obligations. Installed capacity of wind and solar resources is expected to continue to increase within the MISO footprint, although more slowly than even a few years ago. Within the MISO footprint, energy from gas generation has increased from less than 10% of total electric generation in 2005, used primarily to meet the needs during peak demand conditions, to approximately 48% of total generation in 2024.[4] Meanwhile, coal has declined but still supplies a little more than a quarter of the energy need within MISO, followed by wind at 9%, nuclear at 8%, and solar at 2%.

[4] *MISO 2024 State of the Market Report, Potomac Economics, June 2025, page 6 https://cdn.misoenergy.org/2021 State of the Market Report625295.pdf https://www.potomaceconomics.com/wp-content/uploads/2025/06/2024-MISO-SOM_Report_Body_Final.pdf*

The move toward renewables and gas energy has come at the expense of coal generation, which has been rapidly retiring for several reasons. Coal plants have not been able to consistently compete on short term marginal price with renewable and gas energy. Operationally, the move toward intermittent renewable energy requires coal plants to more frequently cycle on and off. These plants were not designed to operate in this manner. The result is increased maintenance costs and more frequent outages. Older, inefficient coal plants are being retired to avoid spending significant dollars on necessary upgrades to achieve compliance with EPA regulations. Finally, public and investor pressure, coupled with future cost risk associated with the objective of decreasing carbon emissions, has also driven unit retirements.

While coal has been declining, it remains an important source of power for our grid, particularly as this capacity-rich resource has seen an uptick in market capacity revenues. Additionally, President Trump has written executive orders aimed at supporting the coal industry in an attempt to preserve remaining plants. With these market changes, coupled with increasing costs for renewable and gas resources, we are more likely to see some coal units remain online longer than they otherwise would have.



CHANGING MARKET RULES TO HELP ENSURE RELIABILITY

MISO recognizes the major changes in the way energy is being produced. Traditionally, baseload coal plants produced energy at a constant level around the clock, while peaking gas plants were available to come online as needed to meet peak demand. Gradual increases and decreases in energy demand throughout the day and seasonally were easily managed with these traditional resources. As described above, the energy landscape is continuing its rapid change with increased adoption of more intermittent renewable generation which is available when the sun is shining, or the wind is blowing. This creates much more variability by hour in energy production. Some periods will have overproduction (more energy produced than is needed at the time) and other periods will have low-to-no renewable energy production, requiring dispatchable resources to meet real-time demand for power. MISO has recognized the region's energy landscape continues to evolve toward a complex, less predictable future.

Some of the challenges MISO faces are resources that are primarily weather dependent, less predictable weather, less predictable resource outages, and increasing electric load. To maintain reliability with a changing mix of resources, there is an increased importance of ensuring that adequate attributes are available from the fleet such as ramp capability, long duration energy at high output, and fuel assurance. To ensure reliability is maintained, MISO implemented a seasonal resource adequacy construct beginning with the 2023/2024 planning year that focuses on meeting system demand in all hours as opposed to planning for meeting the summer peak demand. As part of the seasonal construct, thermal resource accreditation has shifted from an Equivalent Forced Outage Rate Demand ("EFORd") approach to one that accredits resources based on historical availability during tight operating hours. Accreditation for renewable resources continues to be challenged as MISO received approval to further revise the accreditation approach in 2028 with the introduction of DLOL methodology. The move to DLOL is expected to most affect renewable resources, particularly solar. For example, solar resources were expected to provide about 25% or more of their total installed capacity to cover MISO's reliability requirement. This is expected to drop over time to approximately 5% or below in the summer, CEI South's tightest season. The practical effect is that more capacity will be needed when fully implemented.

Also, MISO continues to study how demand response resources will be accredited. To date, these reforms have provided more certainty that demand response will be there when called upon; however, there is a much higher bar than in the recent past for industrial customers to participate with annual testing and required faster response times to remain a participant in these programs. MISO reforms will continue as reserve margins continue to tighten and increasingly include intermittent renewable resources that make it more difficult to maintain acceptable voltage and thermal limits on the grid than traditional, dispatchable resources.

CEI South has accounted for these changes by incorporating the seasonal construct and DLOL accreditation approach into the Encompass model, and the portfolios in this analysis provide sufficient resources to meet its MISO obligations in all four seasons with limited capacity purchases. Additionally, CEI South analyzed the thermal limits of equipment along with the voltage and reactive power needs of the system for various portfolio options and identified mitigations.

BATTERY STORAGE AND TRANSMISSION RESOURCES

To support greater reliance on intermittent renewable resources, utilities are increasingly considering the opportunity to add battery storage to resource portfolios to help provide availability and flexibility. Lithium-ion ("L-ion") batteries have seen significant cost declines over the last several years as the technology begins to mature. In fact, 2024 All-Source RFP bids for battery storage to replace F.B. Culley 2 as a potential CEI South resource were cost effective for the first time.

There are many applications for this resource, from shifting the use of renewable generation from time of generation to the time of need, to grid support for maintaining the reliability of the transmission system. CEI South has experience operating a 1 MW battery designed to capture energy from an adjacent solar project. This pilot project has provided information that will be helpful in moving forward with a much larger project. The 90 MW battery will be available to discharge energy for four hours and will be available for energy arbitrage and meeting peak load conditions.

Uncertainty/Risk

As demonstrated over the past few years, the future is far from certain. Uncertainty creates a risk that a generation portfolio that is reasonable under an anticipated future fails to perform as expected if the future turns out differently. CEI South's IRP analysis was developed to identify the preferred resource portfolio mix of generation and demand side resources to serve customer energy needs over a wide range of possible future states. CEI South worked with 1898 & Co. to perform two sets of modeling to contribute to the risk analyses, one exposing a defined set of portfolios to a limited number of scenarios and another that exposed the same portfolios to 200 scenarios (stochastic or probabilistic risk assessment). To help better understand the wide range of possibilities for wholesale market dynamics, regulations, technological breakthroughs and shifts in the economy, complex models were utilized with varying assumptions for major inputs (commodity price forecasts, energy/demand forecasts, market power prices, etc.) to develop and test portfolios with diverse resource mixes. Additionally, the risk analysis included sensitivities and qualitative judgement.

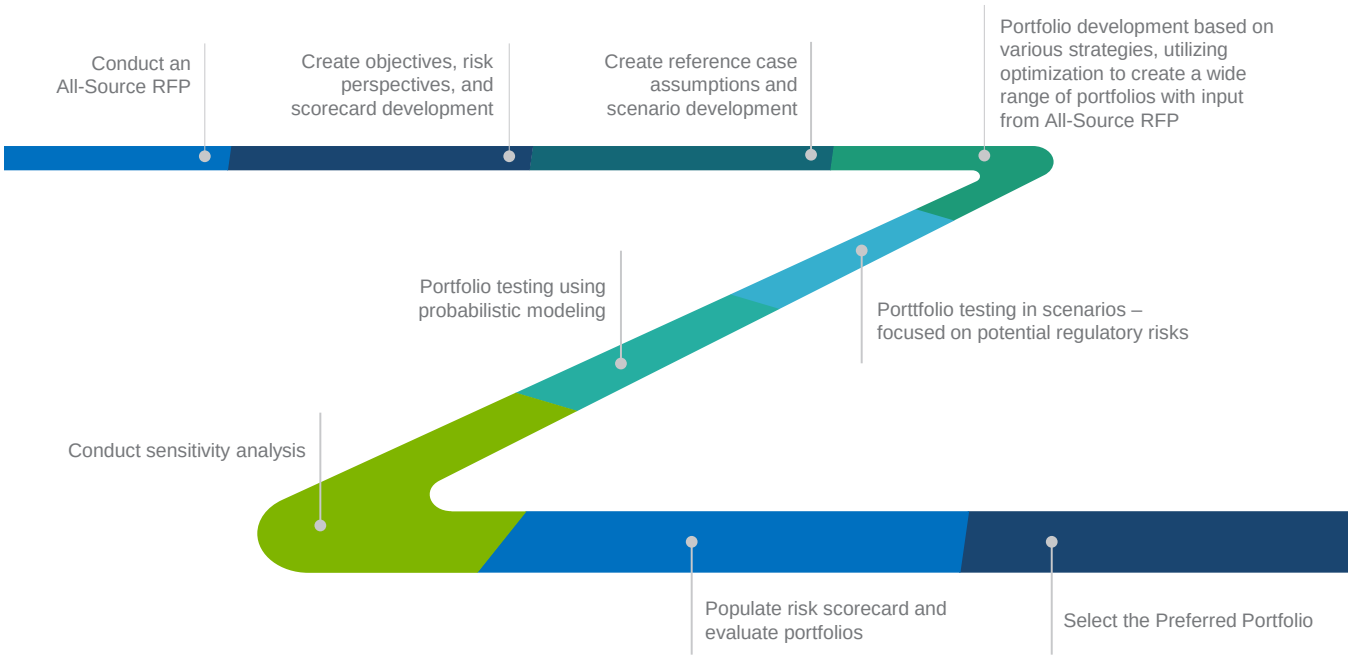


Analysis

CEI South's analysis included a step-by-step process to identify the Preferred Portfolio. The graphic below summarizes the major steps which included the following:

1. Conducted an **All-Source RFP** to better understand resource cost and availability.
2. Worked with stakeholders to develop a **scorecard** as a tool in the full risk analysis to help highlight several tradeoffs among various portfolios of resources.
3. Worked with stakeholders to develop a wide range of **future states**, called scenarios, to be used for testing of portfolios (mixes of various resource combinations to serve customer power and energy need).
4. Worked with stakeholders to develop a wide range of **portfolios** for testing and evaluation within scenarios, sensitivity analysis and probabilistic analysis. Each of these analyses involves complex modeling.
5. Conducted a **risk analysis,** including deterministic and probabilistic modeling with sensitivity analysis.
6. Utilized the **quantitative scorecard measures** and **judgment** to select the Preferred Portfolio (the best mix of resources to reliably and affordably serve customer energy needs while minimizing known risks and maintaining flexibility).

Analysis Process



Stakeholder Process

As in the last IRP, each of the last three stakeholder meetings began with stakeholder feedback. CEI South reviewed requests/comments from the prior stakeholder meeting and provided feedback. Suggestions were taken, and in instances where suggestions were not acted upon, CEI South explained why not. Notes for each meeting were included in question-and-answer format, summarizing the conversations. Additionally, feedback was received, and questions were answered via e-mail (IRP@CenterPointEnergy.com) and with phone calls/meetings in between each public stakeholder meeting by request.

While maintaining the virtual option to participate, CEI South thought it was important to continue face-to-face meetings. All stakeholder meetings were held at CEI South in Evansville, Indiana, with a virtual option for those that could not travel to southwestern Indiana or did not wish to participate in person. Dates and topics covered are listed below.

CEI South held a series of technical meetings with stakeholder groups willing to sign a Non-Disclosure Agreement ("NDA") and participate in ongoing tech-to-tech conversations about critical assumptions related to the analysis, including all significant modeling assumptions. These meetings, along with a data release schedule, helped keep technical stakeholders informed throughout the process and provided an opportunity to engage with CEI South in a way that is not always possible during public stakeholder meetings.

CEI South also incorporated feedback from the Director's report on its previous IRP, along with insights from the annual Contemporary Issues Conference hosted by the IURC. The 2025 Conference topics proved especially timely - highlighting considerations for large load coordination and planning. Discussions underscored the importance of flexibility and preparation to account for the impacts of large load within our planning process. Careful consideration was taken to ensure that the time spent was mutually beneficial to all parties involved.



Based on this stakeholder engagement, CEI South made fundamental changes to the analysis in real-time to address concerns and strengthen the plan. IRP inputs and several of the evaluation measures used to help determine the Preferred Portfolio were updated through this process. CEI South held meetings with interested stakeholders willing to sign an NDA ahead of and in between public stakeholder meetings. This, along with providing modeling inputs, helped to allow for a more productive dialogue throughout the process. CEI South appreciates the time and attention provided by each group that participated in this process.

CEI South utilized stakeholder information to create boundary conditions that were wide enough to produce plausible future conditions that would favor opposing resource portfolios, including the addition of a possible future, the alternate high regulatory scenario. CEI South updated the scorecard to measure risks in each of the five pillars (Affordability, Environmental Sustainability, Reliability, Resiliency, Stability) with a separate section for other market risks. Per the Director's report, CEI South added the 5th percentile of Net Present Value Revenue Requirements ("NPVRR"). CEI South worked closely with stakeholders to consider relevant risks to be included within the scorecard, adding an affordability metric (electric energy burden) that illustrated the 5-10 year incremental impact to energy burden (incremental residential bill impact in 2030 and 2035 divided by Vanderburgh County median household income). This measure highlights near to mid-term price pressure that customers may face for each portfolio. Additionally, CEI South added measures for Dynamic VAR Support ("MVAR") and Short Circuit Ratio ("SCR") from its updated transmission reliability analysis. CEI South also added SOx and NOx emissions and capacity sales/purchases to the scorecard. Adjustments were also made to modeling inputs and assumptions based on direct stakeholder feedback. The following table shows key stakeholder requests made during the process and CEI South's response.



Topic	Stakeholder Comments/Feedback	CEI South Updates/ Responses
Scorecard	Under the Environmental Sustainability Objective: Remove CO_2 intensity, keep CO2-e tons	CEI South believes that there is value in keeping CO_2 intensity, as well as CO_2-e metrics. CO_2 intensity allows the reader to compare CO_2 levels across scenarios.
Scorecard	Include metrics for SOx and NOx	CEI South has added metrics that includes combined tons of SOx and NOx.
Scorecard	Under the Affordability Objective: consider adding an energy burden calculation	CEI South proposes to add electric energy burden, defined as the 5-Year [5] residential rate impact as of July 1, 2025 divided by the Vanderburgh County Median Household Income.
Resource Options	Are the Demand Response proposals subject to discussion/change with Demand Side Management (DSM) Oversight Board	CEI South continues to discuss Demand Response with members of the DSM Oversight Board
Resource Options	Is CEI South considering what the resource mix could be if a resource incentive (updated EDG rate) is included in the IRP?	CEI South is conducting a sensitivity considering a $500 per kW incentive for Distributed Generation solar resource.
Load Forecast	Provide a breakout of peaks by customer class	See graph in 3/19/2025 Stakeholder meeting notes posted at www.centerpointenergy.com/irp
Load Forecast	Why is CEI South using historical rather than forecast temperature, e.g., Purdue University temperature forecast?	CEI South used a linear projection of temperature based on historical data; it is not significantly different from the Purdue University study for the IRP period.
Load Forecast	Requested CEI South to revisit the estimated 12,000 miles for EVs used in the forecast	Itron EV assumption for reference forecast. The 12,000 miles per year for EVs was revised to 9,500 miles per year. This revision is noted in the 5/14/2025 Stakeholder meeting slides

[5] *CEI South ultimately added a 5 and 10 year incremental energy burden per stakeholder request.*

Topic	Stakeholder Comments/Feedback	CEI South Updates/ Responses
Load Forecast	Does the EV charging profile used for CEI South's load forecast account for remote work at home?	The NREL tool, EVI-Pro, documentation does not specifically state any assumptions regarding work from home. The "EVHome" charging profile on slide 61 of the 3/19/2025 stakeholder slides includes some level of charging between 11am-2pm. (slides posted at www.centerpointenergy.com/irp)
Load Forecast	Does CenterPoint have plans to electrify its fleet?	CenterPoint does have plans to electrify its fleet - please see the following link https://sustainability.centerpointenergy.com/energy-transition-goals/fleet/
Commodity Inputs	Does the natural gas forecast assume increased drilling under the current administration?	At this time, CEI South is uncertain how the current administration's policies will affect natural gas prices. Our vendors consider multiple factors when developing commodity forecasts. Utilizing a consensus forecast is an approach CEI South has taken in previous IRPs. These various perspectives allow us to capture the diversity in opinions for future market prices.
Generation Timeline	Regarding Salt Creek Wind, is this project going to service CenterPoint customers or just provide power to the MISO grid as accredited power? If it's going to be service to CenterPoint customers, what kind of transmission loss are you expecting since the power is coming from Iowa?	Please see Witness Swanson's public testimony in Cause No. 46218.
Objectives & Draft Measures	Will the electric energy burden separate electrically heated homes from gas heated homes, or will those be combined in the aggregate?	We'll look at both the customers with electrically heated homes and the customers with gas heated homes. However, either view will show the same relative difference among portfolios.

Topic	Stakeholder Comments/Feedback	CEI South Updates/ Responses
Scenarios	Suggest adding an option where load stays at base. In this scenario, generation capital costs could still be high.	CEI South conducted a lower load sensitivity analysis to evaluate how lower load may impact the scenario(s). An update is included in today's (9/11/2025) Stakeholder meeting.
Scenarios	When looking between high regulatory and alternative high regulatory, can you potentially do the same with low regulatory (an alternative low regulatory with low load)?	CEI South conducted a lower load sensitivity analysis to evaluate how lower load may impact the scenario(s). An update is included in today's (9/11/2025) Stakeholder meeting.
Supply-Side Resource	Can CEIS incorporate real coal price offers made to CenterPoint. The uncertainty variable is not the mining cost as much as the demand.	Due to the confidential and competitive nature of CEIS's contractual coal price this was discussed during the 8/20/2025 Tech to Tech meeting
Supply-Side Resource	How many bids did CEIS receive for storage?	There were 17 standalone storage bids. The 2024 All-Source RFP results were shared during the 3/19/2025 Stakeholder meeting. The presentation is available here: CenterPointEnergy.com/IRP.
Supply-Side Resource	Is CEIS accounting for all costs and benefits, including considerations such as health costs? Will these other benefits be incorporated into the IRP?	Health costs are captured within EPA regulations that are included in the applicable scenarios.
Supply-Side Resource	Has CEIS considered the water pressure nuclear option, such as the Westinghouse AP1000?	The general nuclear option included in the Tech Assessment is representative of a variety of future nuclear options. If you have information regarding technology performance or costs that you would like to see in the model, please email IRP@CenterPointEnergy.com

Topic	Stakeholder Comments/Feedback	CEI South Updates/ Responses
MPS	For the battery storage program, without large enough penetration of batteries, it's hard for benefits to outweigh the costs. Could we look at a battery storage equipment incentive?	We performed cost-effectiveness screening using a range of incentives and adoption rates. In all scenarios the Utility Cost Test ratio was less than 1, which is not cost-effective. Results are included in today's (9/11/2025) Stakeholder meeting.
MPS	For EVs, are customers bringing their own device for the charger? Would customers have to use specific technology to participate?	We are assuming that the customer would supply their own charger, and CenterPoint would provide an incentive to join the program, as well as an annual participation incentive. A managed charging program would require some sort of network connection, which could include Wi-Fi, cellular, or a wired connection. A specific technology would not be required, as control could happen through the charger or telematics through the EVs
MPS	Some DR measures like batteries and water heaters can be used for other grid services (ancillary services, resilience) – how are these benefits being considered in developing levelized costs and/or accounted for in the IRP? Is it possible to treat these like T&D benefits and reduce from the cost side?	When performing cost-effectiveness screening, the benefits include the avoided energy, capacity, and T&D. Resilience and ancillary services have not been a benefit of Demand Response captured in the IRP analysis.
Model Inputs	Is CEIS going to include Scope 3 emissions?	Scope 3 emissions are outside the scope of the IRP as it's related to emissions of the end-user and separate from electricity generation.

Topic	Stakeholder Comments/Feedback	CEI South Updates/ Responses
Model Inputs	Since CEIS is considering nuclear, does CEIS want to run a stochastic process for uranium?	We are currently using publicly available data sources for uranium pricing forecasts. Uranium pricing is not expected to be a major differentiator in the portfolio risk assessment when compared with other cost drivers. Given this, we do not anticipate that running a stochastic process for uranium will materially change the outcomes of the analysis.
Model Inputs	Is CEIS planning to use the MISO published 2025/2026 indicative DLOL results for the solar and wind accreditation assumptions?	We have revised the accreditation values to interpolate between the first season of DLOL and 2035. Providing a smoother shift in accreditation. Revised Solar and Wind capacity accreditation forecasts are included in the 9/11/2025 presentation's Appendix.
Model Inputs	Recommendation to analyze two DER resource portfolios, Distributed Capacity Procurement (DCP) and Virtual Power Plants (VPPs) in CEI South's 2025 IRP	CEI South's evaluated demand response programs that align with the intent of both DCP and VPP programs as well as a DG Solar incentive during the IRP process. Updates on the evaluations are included in today's (9/11/2025) Stakeholder meeting.
Modeling	Scenario Portfolios – Explain why manual modifications applied to scenario portfolios to align with the Reference Case load	1898 & Co. posted documentation to the IRP File Share site for technical stakeholders. However, following Stakeholder feedback, CEI South decided to remove the manual modification.
Modeling	Scenario Portfolios – Request to re-run the capacity expansion simulation instead of the production cost simulation	1898 & Co. posted documentation to the IRP File Share site for technical stakeholders. However, following Stakeholder feedback, CEI South decided to remove the manual modification.

Topic	Stakeholder Comments/Feedback	CEI South Updates/ Responses
Modeling	Scenario Portfolios – Request to share documentation illustrating manual modifications made to the scenario portfolios	1898 & Co. posted documentation to the IRP File Share site for technical stakeholders. However, following Stakeholder feedback, CEI South decided to remove the manual modification.
Modeling	Build Limits – Request for CEI South to consider running scenarios with relaxed limits	CEI South ran a simulation and chose to relax limits to allow more resources to be selected within the capacity expansion model.
Modeling	Consider a study with FB Culley 3 retiring in 2030	Given the unprecedented amount of uncertainty at this time and future transmission upgrades that will help with system reliability and resilience, it would not be prudent to consider retirement prior to 2031/2032, as is being considered within this IRP.
Affordability Measure	Request for energy burden calculation	CEI South will make the energy burden workpaper available to technical stakeholders with a signed NDA.
Rates	Request to provide guidance on bill itemization	Please see the CenterPoint website, where is shows an explanation of the bills. https://www.centerpointenergy.com/en-us/residential/customer-service/resource-hub/understanding-your-bill?sa=in

Meeting materials for each meeting can be found at **CenterPointEnergy.com/IRP** and in Technical Appendix Attachment 4.2 Stakeholder Materials.

Next Steps

CEI South's flexible plan provides two paths forward, depending on what the future holds. If a large load customer agreement is not made prior to the next IRP in 2028, CEI South will move forward with the Preferred Portfolio. With this path, there are a few items that must be done in the short-term action plan.

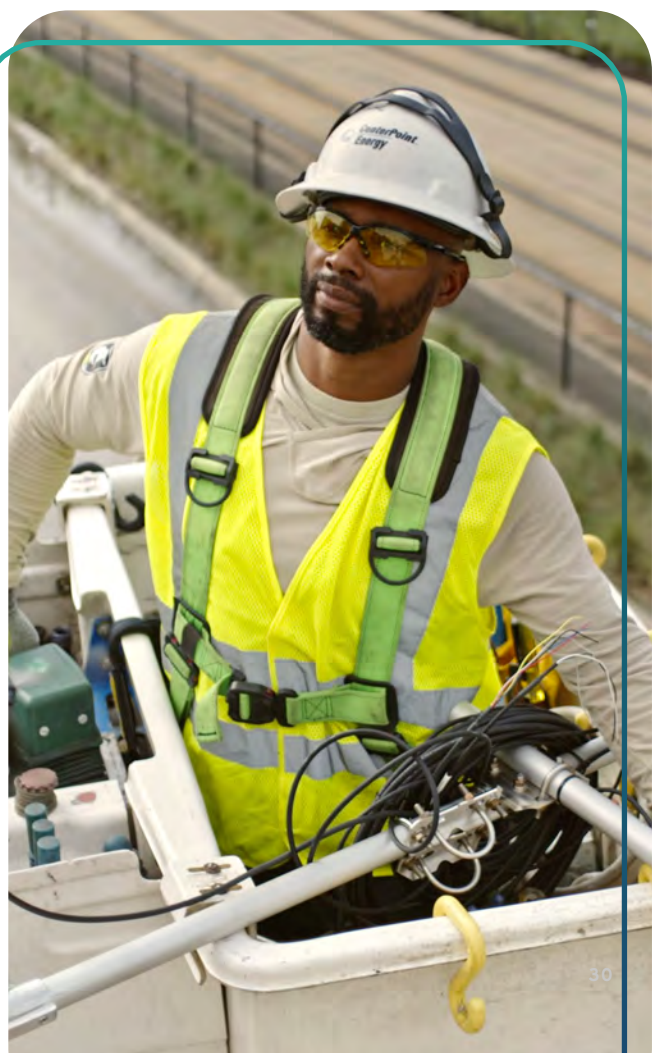
First, CEI South will continue to implement the generation transition that was identified in prior IRPs. CEI South is currently pursuing three renewable projects that are scheduled to be online in 2026: 147 MW Galesburg Wind (approved PPA), 150 MW Wheatland Solar (approved PPA), and 170 MW Salt Creek Wind (approved PPA). These projects will continue to diversify CEI South's generation mix.

Secondly, CEI South will conduct two RFPs to determine current pricing for capacity and battery storage for replacement of F.B. Culley 2 interconnection in the next three years. Having run past its useful life, F.B. Culley unit 2 (coal) is slated for suspension at the end of this year. FERC rules allow for replacement of the interconnection within 3 years of suspension. CEI South will continue to evaluate the proper path forward with consideration for Indiana's five pillars. Should CEI South choose to reutilize the interconnection, it will seek approval in a Certificate of Public Convenience and Necessity ("CPCN") before the IURC and modify its Attachment Y with MISO to an Attachment X.

Third, CEI South will file for a DSM plan, consistent with the results of the Preferred Portfolio.

Finally, CEI South will continue to engage with economic development opportunities to help strengthen southwestern Indiana. Should a large load addition materialize, CEI South would diligently work to implement its Alternate Preferred Portfolio that would potentially require multiple CPCNs and approval of a contract with the IURC. These filings will be consistent with the Preferred Portfolio paths. However, the assumptions included in any IRP can change over time, causing possible changes to resource planning. Changes in commodities, regulations, political policies, customer need and other assumptions could warrant deviations from the Preferred Portfolio.

CEI South's plan must be flexible, as several items are not certain at this time, including but not limited to: MISO DLOL, EPA greenhouse gas regulations, cost of resources, policy change, the potential for large load additions, and regulatory risk.



BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

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

Exhibit 81
Joundi Testimony

Tab E

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Midcontinent Independent System Operator, Inc.	**)**	**Docket No. ER24-___-000**

PREPARED DIRECT TESTIMONY OF ZAKARIA JOUNDI EXECUTIVE DIRECTOR, MARKET & GRID STRATEGY

I. PROFESSIONAL BACKGROUND AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND POSITION WITH THE MIDCONTINENT INDEPENDENT SYSTEM OPERATOR, INC.

A. My name is Zakaria (Zak) Joundi. I am the Executive Director, Market & Grid Strategy for the Midcontinent Independent System Operator, Inc. (MISO). My business address is 720 City Center Drive, Carmel, Indiana 46032.

Q. PLEASE DESCRIBE YOUR EDUCATION AND PROFESSIONAL BACKGROUND.

A. I hold a Bachelor of Science degree in electrical engineering, with an emphasis in power systems, from Iowa State University and a Master of Business Administration degree, with an emphasis in finance, from the Indiana University Kelley School of Business. I joined MISO in 2006 and have held multiple positions of increasing responsibilities that span across generation and transmission planning, market administration, seams administration, data and analytics, and resource adequacy (RA). I have also supported numerous MISO initiatives and filings with the Federal Energy Regulatory Commission (Commission), including financial transmission rights (FTR), seams, and RA matters.

Q. PLEASE DESCRIBE YOUR CURRENT ROLE AND JOB RESPONSIBILITIES.

A. In my current role as Executive Director, Market & Grid Strategy, I oversee the team responsible for the design of the MISO markets and the assessment of its performance. One of my primary responsibilities has been serving as the MISO liaison to the Resource Adequacy Subcommittee (RASC), which is the stakeholder led group at MISO focused on RA matters.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to support the resource accreditation reform proposed in this filing.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony begins with a brief discussion of MISO's current approach to resource adequacy, including the challenges with the current accreditation approach and the problem statement MISO developed with stakeholders to address those challenges. Next, I discuss MISO's proposed resource accreditation method and describe the design details associated with that approach. I then discuss MISO's approach to loss of load expectation (LOLE) modeling. From there, I describe the evaluation criteria MISO used to analyze the various options for proposed resource accreditation reforms. Finally, I discuss MISO's implementation timeline, stakeholder engagement, and other key considerations.

Q. PLEASE PROVIDE AN OVERVIEW OF MISO'S PROPOSED RESOURCE ACCREDITATION METHODOLOGY.

A. MISO's proposed resource accreditation methodology is a two-step approach that first measures a resource's expected marginal contribution to reliability using class-level performance (probabilistic approach) and then uses historical resource-level performance (deterministic approach) to accredit individual resources within the class of comparable

resources (Resource Class).[1] The proposed accreditation methodology accounts for a range of reliability risks in the planning and operations horizons by incorporating forward-looking probabilistic analysis and measuring a resource's performance during recent periods of high system risk. Under the proposal, MISO defines the periods of highest system risk identified in the probabilistic analysis as "Critical Hours". Critical Hours include all loss of load hours and, as needed, low margin hours,[2] as further described below. MISO's proposed approach to measure the availability of resources during Critical Hours in its probabilistic analysis is within the marginal Effective Load Carrying Capacity (ELCC) accreditation framework that is used by other market administrators (e.g., PJM Interconnection, L.L.C. (PJM) and New York Independent System Operator, Inc. (NYISO)).[3] MISO refers to its approach as the Direct Loss of Load (DLOL)-based methodology and proposes to use it as the single uniform method for accrediting all Capacity Resources, except External Resources (hereinafter referred to as "Schedule 53A Resources"), that currently participate in its Planning Resource Auction (PRA). In the simplest terms, the proposed two-step approach can be described as first determining the size of a pie (accreditation for an entire resource class) and then second, allocating or divvying up the pie (individual resource level accreditation) as shown in Figure 1 below.

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[1] The term "Resource Class" as used in Schedule 53A and this testimony means a group of Capacity Resources, except External Resources, with similar operating characteristics whose Resource Class-level UCAP has been determined based on the LOLE analysis and is further described in Schedule 53A.

[2] Low margin hours are comprised of those hours where available generation in excess of load is less than or equal to 3% of load in that hour (*i.e.*, low margin) up to a cap of 1,950 hours in each Season.

[3] *See PJM Interconnection, L.L.C.*, 186 FERC ¶ 61,080 (2024). *See* also *New York Indep. System Operator, Inc*., 179 FERC ¶ 61,102 (May 10, 2022).

The proposed reform is consistent with MISO's Market Design Guiding Principles. It aligns operational needs with non-discriminatory market and planning requirements, and results in transparent market prices that reflect marginal contributions to reliability during highest risk hours.

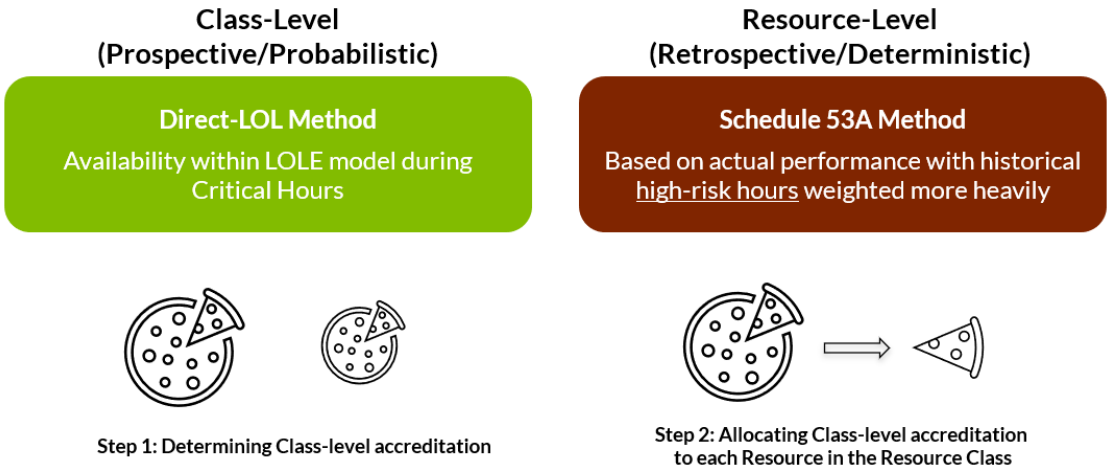


Figure 1: MISO's proposed accreditation methodology

III. OVERVIEW OF MISO'S APPROACH TO RESOURCE ADEQUACY

Q. WHAT IS RESOURCE ADEQUACY?

A. Resource adequacy refers to the ability of the bulk electric system to serve electricity demand while also providing enough excess supply to achieve a threshold level of grid reliability. One such measure of reliability is the industry-accepted Loss-of-Load Expectation (LOLE) target of one day of loss of load every ten years. Following the Commission's acceptance of MISO's Seasonal Resource Adequacy Construct and Seasonal Accredited Capacity filing in August 2022,[4] and commencing with MISO's

[4] *See Midcontinent Independent System Operator, Inc.*, 180 FERC ¶61,141 (2022).

Planning Year 2023/2024 PRA, MISO now makes such LOLE determinations on a seasonal basis, for each PRA.

Q. WHICH ENTITIES ARE RESPONSIBLE FOR ACHIEVING RESOURCE ADEQUACY IN THE MISO FOOTPRINT?

A. In the MISO footprint, the primary responsibility for achieving resource adequacy rests with Load Serving Entities (LSE) with oversight by Relevant Electric Retail Rate Authorities (RERRA), as applicable by jurisdiction. MISO facilitates these efforts by administering its Open Access Transmission, Energy and Operating Reserve Markets Tariff (Tariff)-defined Resource Adequacy Requirements (RAR) and the PRA, which LSEs use to demonstrate their ability to serve seasonal peak demand and provide a sufficient margin of excess supply.

Q. BRIEFLY DESCRIBE THE RESOURCE ADEQUACY CHALLENGES THAT ACCOMPANY THE ONGOING TRANSFORMATION OF THE ELECTRICITY SECTOR.

A. Historically, periods of risk have been driven primarily by periods of high demand. The composition of that demand would evolve over time, but the periods of highest load were generally relatively consistent and forecastable, historically based on the Summer peak. At the same time, generation availability was largely driven by uncorrelated unit outages, which were thus assumed to be independent. Because of this relative stability, grid reliability was achieved by ensuring enough generation capacity existed to reliably serve the peak load based on a single occurrence during the year (e.g., the Summer coincident peak). In addition, frequent, large-scale weather events on the Transmission System have presented challenges to maintaining resource adequacy in the recent past.

A number of factors now require the application of a new approach for determining resource accreditation in MISO, consistent with developments in other parts of the country, to ensure reliable grid operations are maintained going forward. The transformation of the grid is accelerating, resulting in increasing reliance on newer types of generation, such as weather-dependent, highly variable wind and solar resources and energy-limited storage resources. Moreover, projected electrification is expected to increase challenges in the MISO footprint. These drivers are decoupling periods of risk from periods of high demand, upending traditional methods to establish reliability requirements and ensure resource adequacy. Figure 2.a shows how the timing of expected unserved energy[5] (in blue) for the average summer day is expected to shift and move away from times of highest load (in grey), and better align with times of highest load net of wind and solar (in red). The same information and trend is observed for an average winter day, as shown in Figure 2.b. Further, the comparison of the two figures shows how the seasonal distribution of events is expected to shift from summer to winter over the next decade.[6]

[5] The proposed Tariff definition of Expected Unserved Energy as follows: "In the probabilistic study, an estimate of the energy that would otherwise have been used by end use customers but for a supply interruption." See *Midcontinent Independent System Operator, Inc.,* Docket No. ER23-2977-000.

[6] Additional information on this analysis can be found in MISO's 2023 Attributes Roadmap.

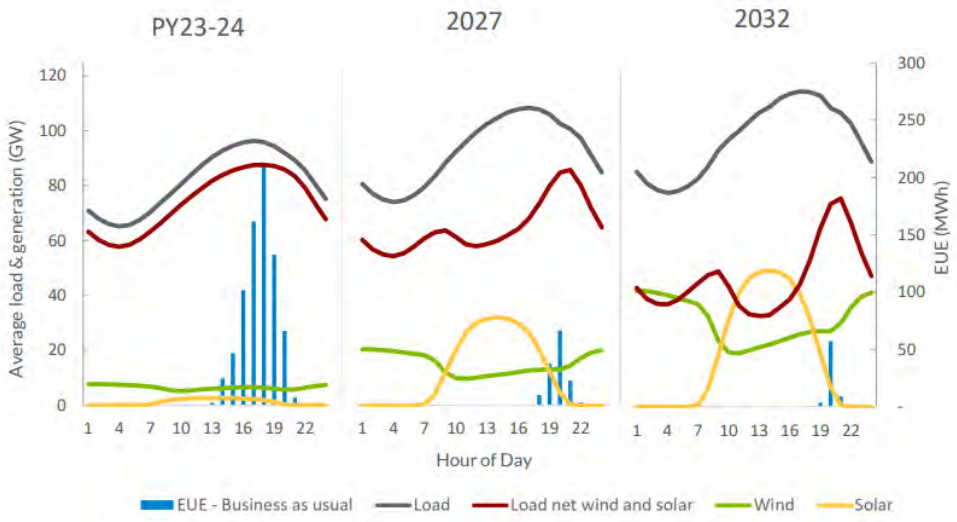


Figure 2.a. Estimated evolution of summer load, net load, wind and solar and expected unserved energy in the MISO footprint

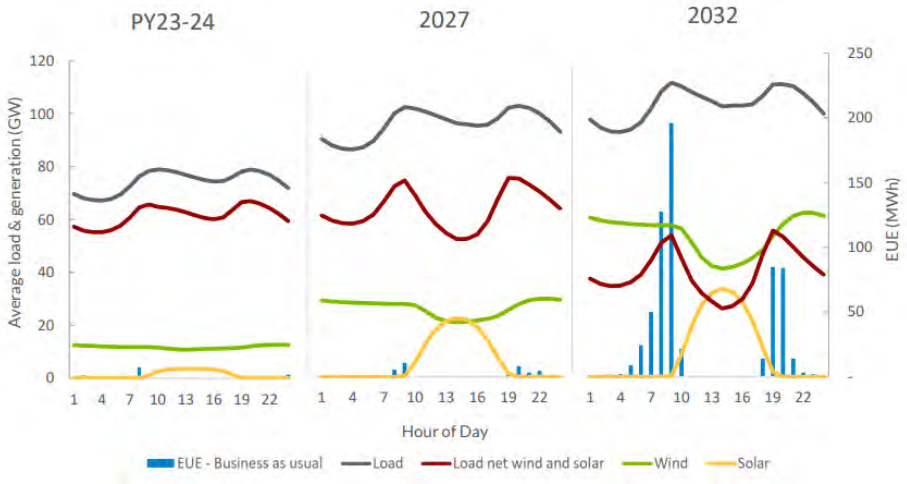


Figure 2.b. Estimated evolution of winter load, net load, wind and solar and expected unserved energy in the MISO footprint

Q. WHAT ROLE DOES ACCREDITATION PLAY IN MISO'S PRA?

A. MISO defines resource accreditation as the capacity value of a resource based on its contribution to system reliability during periods of highest risk. MISO accredits resources for three primary reasons: first, to ensure seasonal reserve requirements are met by

appropriately accounting for resource availability during periods of highest risk; second, to inform long-term investment and retirement decisions by accurately representing the capacity value of a resource in the prompt year; and finally, to appropriately compensate resources for operating practices and attributes that serve the greatest system need. If the accreditation methodology does not align risk, resource availability, and system needs, it results in inefficient market outcomes as well as improper market signals that may leave the system in danger of not having a reliable, cost-effective mix of resources.

Q. WHAT METHODS ARE COMMONLY USED FOR RESOURCE ACCREDITATION FOR THE PURPOSES OF RESOURCE ADEQUACY?

A. One effective way to classify accreditation methods is by separating them into deterministic and probabilistic methods.

Deterministic methods use estimates, generally based on historical performance, to determine resource accreditation. Examples of deterministic methods are seasonal performance, performance during peak load hours, performance during peak net load hours, or performance during historical risk periods.

Probabilistic methods rely on a probabilistic model to examine the loss-of-load probability in the system and how it relates to the performance of resources within that model. The most common probabilistic methods for accreditation include ELCC, equivalent firm capacity (EFC), and marginal reliability improvement (MRI).

The Energy Systems Integration Group (ESIG) provides a comprehensive review of accreditation methods used in the industry.[7] The methods relevant to this filing are further described in this testimony.

Q. HOW DOES MISO CURRENTLY ACCREDIT THE RESOURCES RELEVANT TO THIS FILING?

A. MISO currently uses multiple methods to accredit resources, based on the resource type. See Figure 3 below for an overview of current accreditation methodologies, which can be summarized as follows:

- Thermal resources are accredited pursuant to Schedule 53 of MISO's Tariff.
- Wind resources are accredited through a probabilistic modeling approach to calculate the average ELCC. The class level accredited value is then allocated to individual wind resources based on their actual performance during seasonal peak hours.
- Existing solar resources receive capacity credit based on their actual performance during seasonal peak hours. New solar resources receive a seasonal class average value of 50% for the Summer, Fall, and Spring Seasons, and 5% for Winter.
- Similarly, storage resources receive capacity credit based on their actual performance during seasonal peak hours and new storage resources receive a seasonal class average value of 95%.

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[7] ESIG "New Design Principles for Capacity Accreditation" https://www.esig.energy/new-design-principles-for-capacity-accreditation/

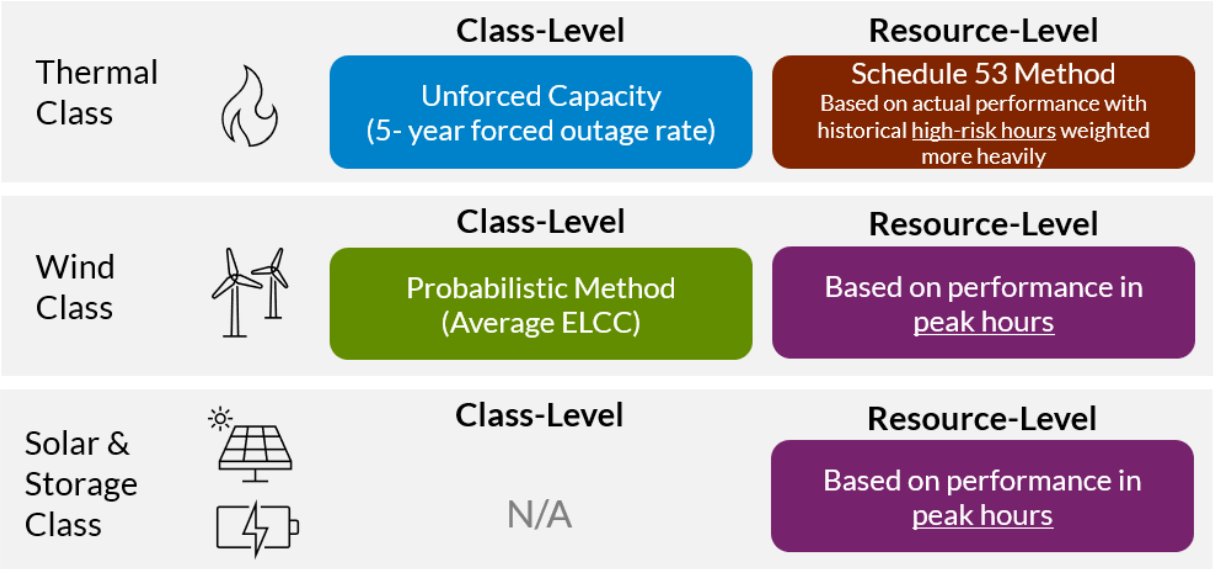


Figure 3: MISO's current accreditation methodology

Q. WHAT ARE THE KEY ISSUES WITH OR LIMITATIONS OF MISO'S CURRENT ACCREDITATION METHODOLOGIES?

A. MISO's current accreditation methodologies have been developed and implemented over time as the resource fleet and reliability needs evolved in the MISO footprint. The application of these different methodologies was appropriate relative to the reliability risks presented at the time of their development. However, and as previously stated, one of the biggest challenges for MISO's Resource Adequacy construct is that periods of highest reliability risk are shifting and are decoupling from times of highest demand. MISO's current accreditation approaches vary amongst resource types, but none of them focus on the marginal contribution of resources during expected periods of highest reliability risk in the probabilistic model. The current approaches thus may result in inaccurate, inconsistent, and potentially overstated accreditation values.

For instance, the Commission recently accepted changes to the accreditation of thermal resources as part of MISO's Seasonal Accreditation (SAC) filing, which established

Schedule 53 of the Tariff.[8] While Schedule 53 enhances the accreditation of thermal resources, it is based on performance across all hours in a Season during the past three years, which does not take into account the effects of possible future events that drive periods of higher risk (such as widespread winter storms). Moreover, by its terms, Schedule 53 is applicable only to thermal resources and Demand Response Resources. Solar and storage resources continue to be accredited based on performance during historic peak load hours, while the risk continues to shift outside of those timeframes. And wind resource accreditation is based on the average ELCC, which can overestimate the capacity value of resources. This issue is further discussed in both the Testimony of Mr. Ming and the Affidavit of Dr. Patton.[9]

This disparity in methods leads to resource accreditation results that are not consistent across resource classes and, importantly, does not allow for the substitution of the accredited capacity of resources on a comparable basis. Similarly, all these methods have the potential to inflate accredited values at the class level, which would lead to an overestimation of how resources contribute to reliability during times of risk and leads to higher reliability requirements. Relying on resources that have received capacity accreditation higher than their actual contribution can lead to incorrect signals for long-term investment and retirement decisions, as well as inefficient market outcomes because even more resources are needed to maintain system reliability.

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[8] *Midcontinent Indep. System Operator, Inc*., 180 FERC ¶ 61, 141 (2022).

[9] *See* Testimony of Mr. Ming ("Ming Testimony") at Q44 and Affidavit of Dr. Patton ("IMM Affidavit") at P21.

Q. IS MISO'S DLOL-BASED METHODOLOGY A TYPE OF MARGINAL ACCREDITATION?

A. Yes.

Q. DESCRIBE HOW MISO'S DLOL-BASED ACCREDITATION METHDOLOGY IS SIMILAR TO A MARGINAL ELCC ACCREDITATION METHOD.

A. MISO's DLOL-based accreditation methodology is consistent with a marginal ELCC framework. The proposed method measures each resource's marginal contribution to reliability during periods of the highest risk (i.e., Critical Hours), and by design it will always capture the risk driven by the evolving resource portfolio in the MISO footprint. As discussed in the Direct Testimony of Mr. Zachary Ming, the marginal ELCC framework measures the reliability value of the next incremental addition of a specific resource type, which is equivalent to measuring the availability of all resources of that resource type during the periods of highest reliability risk. Moreover, the proposed DLOL-based methodology enhances MISO's application of a marginal ELCC accreditation framework by accrediting individual resources based on their historical availability during times of risk.

Q. WHY DOES MISO REFER TO ITS PROPOSED METHODOLOGY AS THE DLOL-BASED METHODOLOGY?

A. While MISO's proposed accreditation methodology is conceptually similar to marginal ELCC, MISO refers to its methodology as "DLOL" because it uses the Critical Hours (loss of load hours plus low margin hours) directly from the probabilistic model to determine the accredited value of each Resource Class (as described in detail below). It is effectively marginal because it measures each resource's marginal contribution during the Critical

Hours, which are representing the periods of highest reliability need. And it is inherently dynamic such that it will always capture the risk driven by the evolving resource portfolio in the MISO footprint.

Q. HOW DOES THE PROPOSED ACCREDITATION METHODOLOGY ALIGN WITH MISO'S MARKET VISION AND MARKET DESIGN GUIDING PRINCIPLES?

A. As discussed in Mr. Ramey's testimony, MISO's market vision is to foster wholesale electricity markets that deliver reliable and economically efficient outcomes. MISO's Market Design Guiding Principles are an important guide to evaluating and developing market enhancements, including this proposed accreditation reform. These guiding principles are listed below:

- Support an economically efficient wholesale market system that minimizes cost to distribute and deliver electricity;
- Facilitate non-discriminatory market participation regardless of resource type, business model, sector or location;
- Develop transparent market prices reflective of marginal system cost and cost allocation reflective of cost-causation and service beneficiaries;
- Support Market Participants in making efficient operational and investment decisions; and,
- Maximize alignment of market requirements with system reliability requirements.

The proposed accreditation methodology is consistent with MISO's Market Design guiding principles supporting efficient wholesale markets as it aligns market requirements with system reliability requirements, facilitates non-discriminatory market participation, results

in transparent market prices that accurately reflect the marginal reliability contributions during Critical Hours, and supports efficient operational and investment decisions.

Q. WHAT ARE THE PRIMARY BENEFITS OF THE PROPOSED ACCREDITATION APPROACH?

A. The proposed accreditation methodology is a balanced approach that captures a range of reliability risks in both the planning and operations horizons by incorporating forward-looking probabilistic analysis along with a resource's actual performance during recent periods of high system risk. The DLOL-based methodology uses a probabilistic model to estimate the expected contribution to reliability of each Resource Class under a wide range of system conditions, while Tier 1 and Tier 2 RA Hours (as currently defined in Schedule 53 and to be incorporated in Schedule 53A of the Tariff) deterministically measure the actual performance of individual resources during historical periods of highest system risk. The combination of the Resource Class-level accreditation and resource-level allocation methodologies accounts for both expected risks in the future and operational risk that has been realized in the recent past (Figure 4 below).

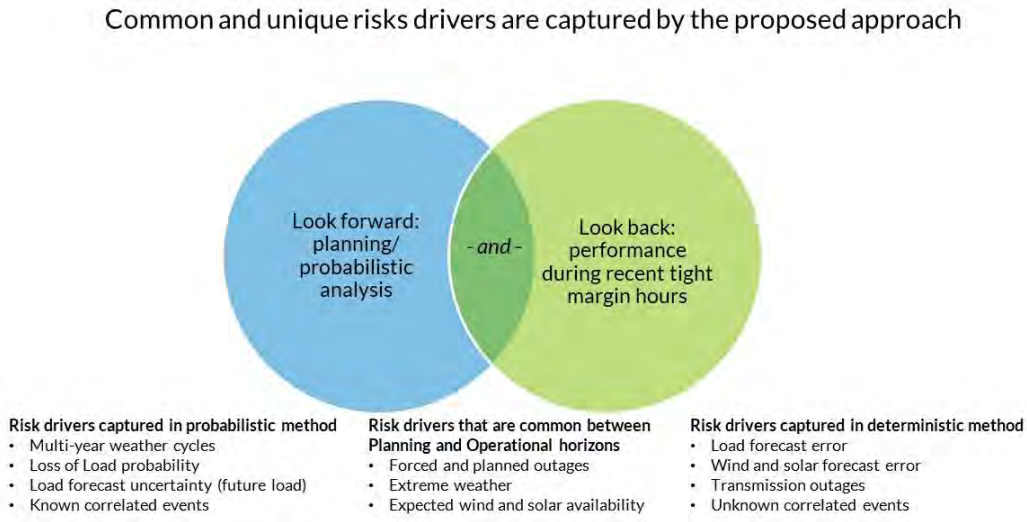


Figure 4: A wide range of risks challenge resource adequacy; a new accreditation approach is needed to capture different risk factors

The proposed DLOL-based accreditation methodology provides the following significant benefits when compared to other accreditation methodologies including:

1. Aligns accredited resource values with expected performance during high-risk hours of operation;
2. Provides a consistent determination of accreditation across all Resource Classes, which is an improvement over the current practice of employing different approaches for different classes. By accrediting all resources during the same time periods and using the same methodology, direct substitution from one class to another is possible as they offer equivalent marginal reliability contribution per accredited MW. This allows resource owners to make the most rational decision for their needs and occurs without altering the overall reliability of the system;
3. Aligns the determination of the system Planning Reserve Margin Requirements (PRMR), Local Reliability Requirements (LRR), and resource accreditation

values used to meet these requirements through the same underlying probabilistic model;

4. Reflects interactions between Resource Classes. Under the DLOL-based methodology, correlations between Resource Classes and their availability during periods of highest system risk are accounted for through the use of a single probabilistic analysis. As each Resource Class has a unique set of operating characteristics, there is value in having a diversified system portfolio and capturing the interactions between all Resource Classes within the same probabilistic analysis. This results in more accurate accreditation and recognizes how the composition of Resource Classes within the system influences system risk;
5. Disentangles random factors that may have occurred historically, such as severe weather or catastrophic outages, from the expected performance characteristics of a resource under the wide variety of events that are captured in the probabilistic model. Relying only on historic events may distort a resource's accreditation causing that resource to appear to have a reliability value that is different than what it truly possesses. The DLOL-based methodology allows the true reliability value of all resources to be more accurately estimated;[10]

[10] A good example of this is provided by wind resources. During a three-year lookback period, there may have been random events that can cause wind resources to have performed significantly better or worse than their expected performance. By using a probabilistic model that captures a wide variety of conditions, the true expected performance signal can be distinguished from the short-term fluctuations that may cause a resource to be mis-accredited.

6. Unlike certain other accreditation methodologies (e.g., those based on average resource accreditation), the DLOL-based methodology does not alter the risk profile on the system and allows for measurement of the actual contribution of resources during times of greatest risk; and,
7. Informs efficient investment in and retirement decisions of resources. By accrediting Resource Classes using the DLOL-based methodology, resource owners are sent the proper signals to invest in resources that offer the greatest reliability value and most economically achieve target reliability. The DLOL-based accreditation methodology provides resource owners with the information necessary to ensure integrated resource plans include resources with the necessary attributes to maintain resource adequacy within the MISO Region.

These benefits work together to generate a system that is economically efficient and achieves the target reliability performance level. The proposed method provides the proper incentives to maintain a diversified resource mix while recognizing the different performance characteristics of the designated Resource Classes. It does this in a computationally and intuitively efficient way without the need for artificial adjustments that may be arbitrary and complex. Additional benefits of this "blended" approach are further described in Section VI of my testimony.

Q. WHY IS THE PROPOSED DLOL-BASED METHODOLOGY (OR MARGINAL ACCREDITATON) A JUST AND REASONABLE RESOURCE ACCREDITATION APPROACH IN THE MISO REGION?

A. The proposed accreditation methodology is just and reasonable for the MISO region because of the following key benefits and aspects that I have described in detail above:

1. It is non-discriminatory and equally applicable to all types of Resources irrespective of fuel-type and/or technology;
2. It addresses the challenges I described above with the current methodologies – specifically, it accredits resources based on their expected performance during the periods of highest reliability risks; and provides direct alignment between accreditation and planning reserve requirements;
3. It provides appropriate signals for long-term investment and retirement decisions by accurately capturing resources' marginal contribution to reliability; and,
4. It will reduce overall cost and improve the ability to achieve and maintain target system reliability during operations, by accurately capturing resources' marginal contribution to reliability.

I also note that the Commission has already accepted the resource-specific accreditation methodology incorporated in the current proposal, which is currently set forth in Schedule 53 of the Tariff. The proposed DLOL-based methodology builds on the deterministic, resource-specific accreditation approach set forth in Schedule 53 by adding a probabilistic component to determine Resource Class accreditation values, and by applying the proposed methodology to all Schedule 53A Resources.

Q. WHY IS IT IMPORTANT THAT MISO CHANGE ITS RESOURCE ACCREDITATION METHODOLOGY AT THIS TIME?

A. As described above and in Mr. Ramey's testimony, MISO is at an inflection point in its resource portfolio evolution. Increasing penetration of wind and solar generation are shifting the nature of system risk.[11] Existing accreditation methods are not sufficiently robust to capture those risks and are unable to send the proper signals to help ensure the availability of resources needed during Critical Hours. As Market Participants plan rapid changes to their generation fleet, it is important for MISO to adopt an accreditation method that captures performance and availability of resources during the periods of system risks to ensure Resources needed to maintain overall reliability of the Bulk Electric System are appropriately incentivized. Inaccurate accreditation sends the wrong signals for the resources needed to maintain system reliability and can leave the MISO system ill-prepared for high-risk operations when resources are most needed. It is essential to make a course correction in MISO's accreditation methodology as soon as possible to provide proper guidance to Market Participants and regulators who are actively planning future resource additions and changes to the grid.

IV. PROPOSED ACCREDITATION METHODOLOGY

A. OVERVIEW OF DLOL-BASED ACCREDITATION METHODOLOGY

[11] *See* MISO's Attributes Roadmap (December 2023), available at: https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf;

See also MISO's Renewable Integration Impact Assessment, Summary Report (February 2021), available at: https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf

Q. PLEASE DESCRIBE THE ACCREDITATION METHODOLOGY MISO IS PROPOSING.

A. MISO is proposing to reform its capacity accreditation methodology for all Schedule 53A Resources, using a two-step process.

First, Resource Class-level accreditation, in megawatts (MW), will be calculated directly from MISO's LOLE analysis (which is a probabilistic analysis). This step calculates the expected availability of each resource during Critical Hours, which include loss-of-load hours and low margin hours, within the probabilistic model and aggregates these values to the Resource Classes that are established in Schedule 53A of the Tariff.

The second step of the proposed accreditation methodology utilizes the same concept that has been previously accepted by the Commission and currently implemented for Schedule 53 Resources. The Resource Class-level accredited value (MW), determined by the probabilistic component of DLOL-based methodology described above, is allocated among the individual resources in a Resource Class on a pro-rata basis using their contribution to the class-level historical performance. Historical performance, or Intermediate Seasonal Accredited Capacity (ISAC), is calculated using a two-tiered weighting structure based on an individual resource's average real-time availability during Tier 1 and Tier 2 RA Hours, as currently defined in Schedule 53 of the Tariff and as incorporated in the proposed Schedule 53A. Tier 2 RA Hours are identified based upon the prior three years of operational experience. These hours represent the periods of highest risk and greatest need during a Season and throughout the year during the past three-year period. They include Emergency Declaration periods and the hours when the operating margin is at its lowest. Tier 2 RA Hours receive 80 percent of the weight, while Tier 1

Hours, which include all other hours during the Season, are weighted at 20 percent. Allocating the Resource Class-level accredited value among the individual resources in a Resource Class based on their historical performance during the periods of highest risk will create performance incentives for individual resources and is expected to improve performance over time when those resources are needed the most. Figure 5 below provides a high-level summary of the design features of the proposed accreditation methodology.

Design Feature	Resource Class-level UCAP	Individual Resource ISAC
Approach	Probabilistic/Prospective	Deterministic/Retrospective
Hours Used	Critical Hours = Loss of Load (LOL) hours + low margin hours Loss of load hours = hours with unserved energy Low margin hours = hours with incremental generation ≤ 3% of the load	Tier 1 and Tier 2 RA hours
Hour Cap	If # of LOL hours ≥ 1,950 in a Season, No Cap If # of LOL hours < 1,950 in a Season, Cap of 1,950 Hours per Season	If # Max Gen hours per Season per Planning Year < 65 Hours, Tier 2 RA Hours capped at 65 Hours
Margin Calculation	Low margin hours are determined from the difference between modeled generation and load + net imports then capped at 3% of load	Operating margin to determine the hours to use for Tier 2 RA hours is based on historical margin as defined in the Schedule 53A
Availability Calculation	Average availability during Critical Hours	(Average availability in Tier 1 hours * 20%) + (average availability in Tier 2 RA hours * 80%)
Planned and forced outage treatment	Included utilizing 5-year annualized planned maintenance rates and 5-year seasonal forced outage rates	Included unless a planned outage meets exemption criteria
# of years analyzed	30 historical correlated load and weather years, 5 load forecast errors and numerous outage draws	3 years

Figure 5: Comparison of key design features for each step of the proposed two-step accreditation methodology

B. CLASS-LEVEL ACCREDITATION CALCULATION

Q. PLEASE DESCRIBE THE KEY COMPONENTS OF THE PROPOSED DLOL-BASED ACCREDITATION METHODOLOGY?

A. The key components of the proposed accreditation methodology include: the determination of Resource Classes; identification of Critical Hours; the determination of LOLE and PRMR through MISO's probabilistic analysis; and, the determination of Tier 1 and Tier 2 RA Hours. Each of these key components is described in detail below.

Q. PLEASE DESCRIBE HOW THE RESOURCE CLASS-LEVEL ACCREDITATION IS CALCULATED USING THE DLOL-BASED METHODOLOGY.

A. The Resource Class-level accreditation value will be determined directly from MISO's probabilistic analysis that is currently used by MISO to meet its annual and seasonal LOLE targets. This step determines the expected availability of each Resource Class during Critical Hours observed in the probabilistic model. Critical Hours are defined as the set of loss of load hours (all hours with unserved energy) and hours in which the difference between available generation (including net imports) and load is equal to or less than three percent (3%) of the load in the probabilistic model. For those Seasons with greater than or equal to 1,950 loss of load hours, Critical Hours will include all loss of load hours. For any Season with less than 1,950 loss of load hours, Critical Hours will also include low margin hours comprised of those hours where available generation in excess of load is less than or equal to 3% of load in that hour in the Season. Once the Critical Hours are identified for each Season, weights are calculated for each of the Critical Hours such that the hours with lowest margin (or highest unserved energy) receive the largest weight while the highest margin hours will receive the lowest weight. After calculating the weights for each Critical Hour, Critical Hours will be capped at 1,950 hours for each Season that has less than 1,950 loss of load hours. Finally, the Resource Class-level accredited value (MW) will be calculated as the weighted average of each Resource Class's performance during the Critical Hours by Season. MISO has proposed to adjust its definition of Unforced Capacity (UCAP), to reflect this Resource Class-level accredited value. Figure 6 illustrates the sequence of events described above.

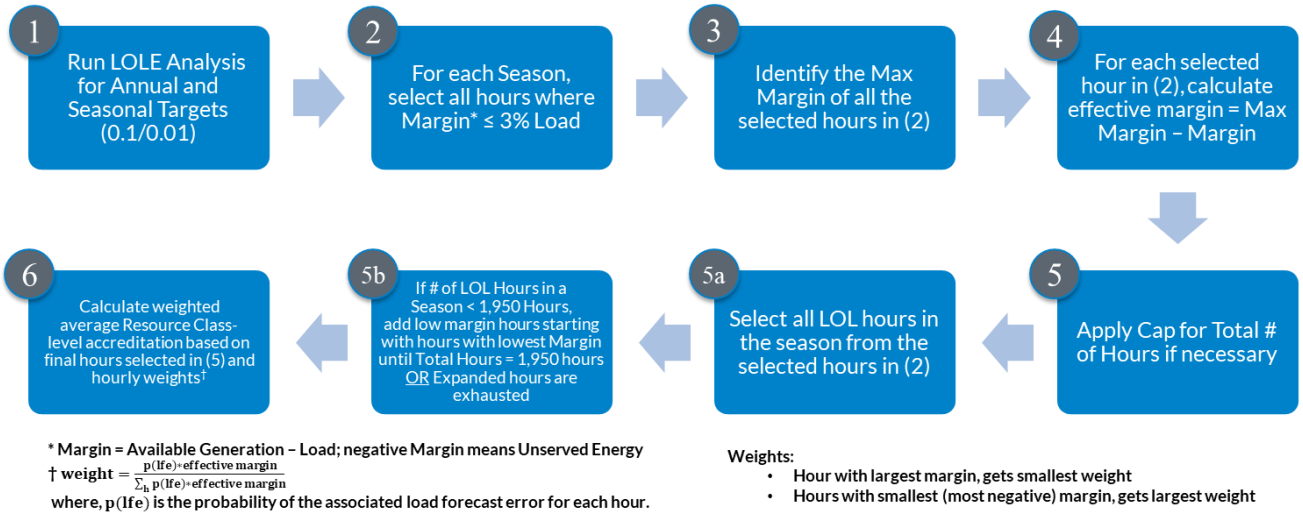


Figure 6: Flow chart of Resource Class-level Accreditation Calculation

Q. PLEASE GIVE AN OVERVIEW OF MISO'S PROBABILISTIC ANALYSIS USED FOR CALCULATION OF RESOURCE CLASS-LEVEL ACCREDITATION.

A. As described above, the Resource Class-level accreditation value will be determined directly from MISO's probabilistic analysis that is currently used by MISO to meet its annual and seasonal LOLE targets. MISO's LOLE analysis includes a Monte Carlo probabilistic simulation using 30 years of correlated load and weather data for each of five load forecasts that incorporates economic uncertainties and associated probabilities into the forecasts. MISO determines the adjustment to capacity in the probabilistic model that would bring the MISO system to the 1 day in 10 years LOLE standard on an annual basis. Under MISO's Seasonal Resource Adequacy Construct, the annual LOLE of 0.1 days/year is not evenly applied across each Season and is dependent on observed risk in the model, although each Season must show a minimum LOLE of 0.01 days/year. If, on an annual basis, a Season is not showing a minimum of 0.01 LOLE, modeled capacity is further reduced through a negative adjustment unit to find the point at which risk is at least equal to the minimum LOLE target of 0.01 days/year. Further details about the application of

MISO's resource adequacy LOLE modelling process are described in Section V of my testimony.

Once the Monte Carlo simulations are complete and seasonal LOLE targets are met, MISO will calculate the Resource Class-level accreditation and seasonal Resource Adequacy Requirements as further described below.

Q. PLEASE DESCRIBE HOW MARGIN IS CALCULATED TO IDENTIFY CRITICAL HOURS FROM THE LOLE MODEL.

A. MISO calculates margin for each hour of each Season for all iterations included in its LOLE analysis. The margin is calculated as the difference between total available generation, including net imports, and load, for the hour. The MW adjustment to reach the seasonal LOLE targets is included in the total available generation.

$$margin = \sum generation - load + net\ imports$$

Once margin is calculated, MISO identifies all hours with margin that is equal to or less than 3% of the load for the hour in each Season. This includes two subsets of hours: i) a loss of load hour, where there was a loss of load due to available generation being less than the required load, i.e. when margin is negative, and ii) low-margin hours, where there was no loss of load, i.e. when margin is positive, but less than 3% positive margin.

Q. WHY WAS A 3% MARGIN CHOSEN FOR USE IN THE DETERMINATION OF CRITICAL HOURS?

A. MISO chose a margin of 3% as it provides a good balance between stability of results and highest-risk hours. These highest-risk hours are representative of periods when MISO typically would issue Emergency Declarations in real-time. MISO originally considered only the loss of load hours as the Critical Hours in its proposed design. Through the review

of preliminary results based on its original design of considering loss of load hours only, and stakeholder discussions on the proposed original design, MISO identified possible scenarios where Seasons may experience too few loss of load hours and where hours with increased reliability risks may not otherwise be included. This could occur, for example, where the available generation is just enough and slightly higher than the load but not enough where there is sufficient margin to be considered as low reliability risk. Additionally, the scenario of low number of loss of load hours in any Season also introduces the possibility of instability in the year-over-year results. In response to these issues, MISO expanded the number of hours used to develop the Resource Class-level accreditation to include low margin hours.

The decision to expand hours for stability and accredit performance during the highest risk hours, however, also creates a tension. Margins as high as 5% dilute the signal being sent by the highest-risk hours, while a margin as low as 1% may potentially skip hours with increased reliability risks and may potentially introduce instability in the results year-over-year, especially for the Seasons when LOLE target is as small as 0.01 day in a year. The proposal to use 3% margin to identify low margin hours for inclusion in Critical Hours from the probabilistic model provides an appropriate balance between the need for stability and the need for accurately reflecting the resource performance during the periods of highest reliability risks.

Q. PLEASE DESCRIBE HOW MISO CALCULATES WEIGHTS AND THE CAP FOR CRITICAL HOURS.

A. After selecting all loss of load hours and low margin hours for each Season, MISO will use the following steps to calculate weights for each selected hour and then apply a cap, if necessary, to calculate Resource Class-level accreditation:

1) Within each Season, the hour with the maximum positive margin is identified from all the low margin hours. This "max margin" is the single maximum margin across all 30 weather years such that there are four (4) total max margin values, one (1) for each Season.

2) Next, for each hour identified in Step 1, effective margin is calculated relative to the max margin hour. This ensures that all values are positive, which is necessary for a weighted sum operation and ensures that the hour with largest unserved energy has the greatest weight, while the hour with the largest margin receives the smallest weight. If the hour with the max margin is included, this hour will receive zero weight.

$$effective\ margin = \max margin - margin$$

3) The number of Critical Hours to be used is capped within each Season based on the following procedure:

   i. All loss of load hours are used in the final calculation, regardless of the number of loss of load hours. Using all loss of load hours regardless of the number of loss of load hours is vital to fully capture all the expected reliability risks observed in the probabilistic model.

ii. If there are fewer than 1,950 loss of load hours per Season, MISO proposes to use low margin hours for the Resource Class-level accreditation calculations but cap the total number of Critical Hours at 1,950. For this step, hours with positive margin are selected beginning with the smallest effective margin until the cap is reached or until all low-margin hours within the Season have been selected. If the total number of Critical Hours are fewer than 1,950 hours between the loss of load hours and low-margin hours, then all loss of load hours and low-margin hours are used, and the cap will not be reached. Loss of load hours will never be excluded, and hours with greater than a 3% margin will never be included in the final selection of Critical Hours for Resource Class-level accreditation calculations. Figure 7 provides an example of how MISO will utilize loss of load hours and low margin hours to identify Critical Hours used for the Resource Class-level accreditation calculations.

Case	Type of hour	Summer	Fall	Winter	Spring
PY23-24	Loss of Load (LOL)	2,703	265	201	240
	LOL + low margin hours*	7,394	934	1,118	1,562
	Used for Resource Class-level UCAP calculations	2,703	934	1,118	1,562

*Low margin hours are all non-LOL hours with margin < 3% load

Figure 7: Example of loss of load hours and low margin hours to identify Critical Hours

4) Next, the weights are calculated and normalized using: a) the probability associated with the load forecast error scenario within the probabilistic model that the selected Critical Hour belongs to, and b) the effective margin developed in Step 2 above. The weights are normalized so that the sum equals one (1).

$$weight = \frac{p(lfe) * effective\ margin}{\sum_h p(lfe) * effective\ margin},$$

where $p(lfe)$ is the probability of the associated load forecast error for each hour. The load forecast error (LFE) values are included in the probabilistic analysis to account for economic load uncertainty and is documented in further detail in MISO's LOLE Study Report.[12] By way of example, the probability associated with each load forecast error that was used in the Planning Year 2023-2024 LOLE Study can be found in Figure 8 below.

LFE Levels				
-2.0%	-1.0%	0.0%	1.0%	2.0%
Probability assigned to each LFE				
4.8%	24.1%	42.1%	24.1%	4.8%

Figure 8: Probability associated with each load forecast error

5) Finally, the total availability is calculated for a Resource Class for each Critical Hour designated in step 3, and those values are averaged for each Season using the weights discussed in step 4. This results in the Resource Class-level accreditation, referred to as Resource Class-level UCAP in the MISO Tariff.

The seasonal Resource Class-level UCAP calculated using the steps described above represents the megawatts that a Resource Class is expected to contribute during times of highest reliability risk expected during the Season.

[12] See Section 3.3.2 in the PY2023-2024 LOLE Study Report

Q. WHY IS MISO WEIGHTING THE HOURS?

A. Weighting the hours based on margin recognizes that not all the simulated events are equal, by assigning greater weights to those hours that have the highest unserved energy. It also provides a distinction between loss of load hours (with negative margins) and low margin hours (with zero or small positive margins), by providing higher weights to the former. The weighting system ensures that the expected reliability risk during Critical Hours is being appropriately accounted for in the Resource Class-level accreditation calculation.

Q. WHY WAS THE PROPOSED WEIGHTING SCHEME CHOSEN?

A. MISO considered alternative weighting schemes, ranging from equal weights for all hours, weights based on the amount of unserved energy, combining the loss of load hours and low margin hours with a fixed ratio (similar to the combination of Tier 1 and Tier 2 RA hours in Schedule 53), and alternative weighting based on margin. The selected scheme was chosen because it provides consistent emphasis on the hours with highest unserved energy, thereby appropriately accounting for the magnitude of expected reliability risks in each hour. Moreover, the approach chosen preserves the ordering of hours with respect to margins (so hours with larger positive margins always receive smaller weights), and it is numerically stable regardless of whether the group of hours include only loss-of-load hours, a few low margin hours, or a large number of low margin hours.

Q. PLEASE EXPLAIN WHY A CAP ON THE NUMBER OF LOW MARGIN HOURS IS NEEDED.

A. Because system risk is not evenly distributed across Seasons, the number of loss of load hours found in the probabilistic model varies widely across Seasons. Figure 7 above, shows that for the Planning Year 2023-2024 simulations, the Summer Season experienced

2,703 hours with unserved energy, but the rest of the Seasons did not exceed 265 hours. Critical Hours were considered to avoid calculating accreditation values in a small group of hours for the less critical Seasons, which could lead to numerical instability and large variations in results year over year.

Hours are capped to establish a balance between improving numerical instability (by including low number of hours) and diluting the contribution of loss of load hours, if they represent too small of a fraction of the total Critical Hours. The cap for number of system hours and the use of the weighting described above work together to prioritize the hours that are most critical from reliability risk perspective and take advantage of the larger pool of hours for the calculations.

Q. WHY IS A CAP OF 1,950 HOURS WHEN LOW MARGIN HOURS ARE INCLUDED IN THE CRITICAL HOURS REASONABLE?

A. Applying the logic of 65 Tier 2 Resource Adequacy (RA) hours per Season from the current Schedule 53 calculations for each of the 30 weather years used in the probabilistic model, MISO selected 65 hours times 30 weather years, which equals 1,950 hours per Season as the cap when low margin hours are included in the number of hours for the Resource Class-level UCAP calculations. As Figure 7 above shows, the number of loss of load hours in the Summer exceeds the cap in the example for Planning Year 2023-24 and the cap is not binding in the rest of the Seasons.

C. ALLOCATION OF CLASS-LEVEL UCAP TO INDIVIDIUAL RESOURCES

Q. PLEASE DESCRIBE HOW RESOURCE CLASS ACCREDITATION IS ALLOCATED TO INDIVIDUAL RESOURCES WITHIN A RESOURCE CLASS.

A. MISO's resource-level accreditation proposal builds on the Commission-approved SAC methodology for Schedule 53 Resources. As described above, once Resource Class-level accreditation values have been determined based on the probabilistic analysis, MISO will then allocate the Resource Class-level accreditation values (MW) to individual resources within the Resource Class based on their historic performance (ISAC) as set forth in Schedule 53A.

Tier 1 and Tier 2 RA Hours over the previous three years of operations are used to determine resource availability for calculating seasonal ISAC. Tier 1 Hours will determine each resource's real-time availability during normal operating condition hours, and Tier 2 RA Hours will determine each resource's real-time availability during hours with the most difficult operating conditions, including declared maximum generation events. Tier 2 RA Hours are more heavily weighted so that most of a resource's real-time availability will be based on its availability during times of greatest reliability need.

All foundational aspects of MISO's current Schedule 53 Tariff, including outage exemptions, tier weighting, and lead time considerations, remain unchanged except the process to determine a resource's availability for the deficient hours (currently referred as Annual Average Offered Capacity in Schedule 53), when there are less than 65 Tier 2 RA hours in a Season, as discussed further below.

The use of Tier 1 and Tier 2 RA Hours ensures that individual resources are compared to other resources within their Resource Class when the system experiences the highest operational risk. For instance, resources in the solar class may have no output during evening risk hours, but all resources would be affected in the same manner and the allocation within the class would not be impacted. Resources with better performance

during Tier 1 and Tier 2 RA Hours receive a larger slice of the overall Resource Class-level UCAP.

The allocation of Resource Class-level UCAP among all Resources in the Resource Class can be described using the following equation:

$$SAC_i = Resource\ Class\text{-}Level\ UCAP * \frac{Resource\ ISAC_i}{Resource\ Class\text{-}level\ ISAC}$$

Q. PROVIDE AN EXAMPLE OF HOW RESOURCE CLASS-LEVEL UCAP IS ALLOCATED TO INDIVIDUAL RESOURCES WITHIN A RESOURCE CLASS TO DETERMINE THE SEASONAL ACCREDITED CAPACITY.

A. Figure 9 below provides a simplified example of how the Resource Class-level UCAP determined by the DLOL-based methodology is allocated to individual resources in a five-resource class. First, the ISAC for each resource is calculated by weighing Tier 1 Hours at 20% and Tier 2 RA Hours at 80%. The Seasonal Accredited Capacity (SAC) for each resource is calculated by distributing the Resource Class-level UCAP from the probabilistic model, 50 MW, among the units, proportional to their ISAC value. Lastly, each resource's percentage credit is calculated by dividing the resource's SAC by its Installed Capacity (ICAP) value.

Resource	ICAP	Tier 1 Hour Availability	Tier 2 RA Hour Availability	Intermediate SAC (ISAC)	Final SAC	% Credit (SAC/ICAP)
Resource Class-Level UCAP determined by DLOL method from LOLE analysis = 50 MW [U]						
Unit 1	5	2	3	2.8	2.6	52%
Unit 2	10	7	8	7.8	7.3	73%
Unit 3	15	12	14	13.6	12.7	85%
Unit 4	20	10	16	14.8	13.9	69%
Unit 5	25	12	15	14.4	13.5	54%
Total	75	43	56	53.4	50	67%
Formula	[A]	[B]	[C]	[D] = 0.2 * [B] + 0.8 * [C]	[E] = [U]*([D]/Total of [D])	[F] = [E]/[A]

ISAC = (Avg. Tier 1 Hour Availability x 20%) + (Avg. Tier 2 RA Hour Availability x 80%)

Final SAC = Resource Class-level UCAP * (Individual Resource ISAC/Resource Class-level ISAC)

Figure 9: Example of allocation of Resource Class-level accreditation among all Resources within the Resource Class.

Q. WHY IS MISO PROPOSING TO REPLACE ANNUAL AVERAGE OFFERED CAPACITY (AAOC) WITH SEASONAL RESOURCE CLASS-LEVEL UCAP, AS A PERCENTAGE OF RESOURCE CLASS-LEVEL INSTALLED CAPACITY?

A. If there are less than 65 Tier 2 RA Hours in a Season (deficient hours), seasonal Resource Class-level UCAP, as a percentage of Resource Class-level ICAP, is used to determine a resource's availability during those deficient hours. The Resource Class-level ICAP is the sum of the individual ICAP of all resources in a Resource Class. This is a slight deviation from the existing Schedule 53 methodology for filling deficient hours as this process will replace AAOC. MISO is proposing to change only this aspect of the current Schedule 53 methodology to ensure both that the availability of highly variable resources (e.g., wind and solar) is appropriately accounted for in the calculation of a resource's ISAC and to have a uniform method for accreditation of all resources. The current AAOC approach for the deficient RA Hours in any Season works well with Schedule 53 Resources because

their availability across the year does not significantly vary. In contrast, intermittent resources are highly variable in nature and their availability during an RA Hour (or Maximum Generation event) in a Season is likely to be different than their availability during RA Hours in other Seasons. For example, the availability of wind resources in a deficient RA Hour occurring during Summer peak conditions would not likely be similar to the average availability of those resources during RA Hours in the rest of the Seasons. Applying the AAOC approach, however, would result in application of those otherwise non-comparable hours during Seasons when there is an RA Hour deficiency. MISO therefore adopted the new proposed methodology to "backfill" deficient RA Hours to help ensure the comparability of all RA Hours being evaluated. When there is a deficient RA Hour in any Season, it is better to use the expected availability of such resources from the probabilistic model than to use their availability during other times of the year. MISO considered having a different approach than AAOC only for the intermittent resources but decided to not pursue that option to have a consistent approach for all resources.

D. SUMMARY OF KEY TARIFF CHANGES AND DESIGN CONSIDERATIONS FOR THE PROPOSED METHOD

Q. WHY IS MISO PROPOSING TO UPDATE THE DEFINITION OF UCAP AND SAC IN MODULE A?

A. MISO is proposing to change the definition of UCAP because UCAP sets the baseline expected availability of a resource for capacity accreditation and the proposal changes the way that baseline is calculated. The existing UCAP definition sets this baseline based on historic forced outage rates or historic availability and does not adequately account for resource availability observed in the probabilistic model. The DLOL-based methodology

marks a fundamental change in determining UCAP such that the probabilistic model is used to set baseline resource availability at the class level, which is then used in place of the previous baseline. Changing the definition of UCAP does not otherwise fundamentally change subsequent Resource Adequacy processes and calculations such that modifying the definition of UCAP is most consistent with MISO's Resource Adequacy construct. I note that both PJM and NYISO have taken similar approaches within their recent capacity market reforms.[13]

Upon receiving stakeholder feedback related to the Tariff redline changes shared with the RASC, MISO reconsidered the definition of SAC and decided to update it to better reflect how the term is currently used in the PRA. This modification is needed to align with the updated definition of UCAP so that the two definitions are distinguishable. SAC is the final accredited capacity, after accounting for the two-step accreditation process, that is convertible to Zonal Resource Credits for use in the PRA.

Q. WILL THE SYSTEM-WIDE UCAP TO ISAC CONVERSION RATIO STILL EXIST UNDER MISO'S ACCREDITATION REFORM PROPOSAL?

A. No. The system-wide UCAP to ISAC conversion ratio that is currently included in Schedule 53 of MISO's Tariff is no longer relevant under the proposed DLOL-based accreditation methodology. As explained in detail above, the proposed methodology is a two-step process. The first step is to calculate the Resource Class-level UCAP from the probabilistic model and the second step is to allocate the Resource Class-level accreditation to individual Resources within the same Resource Class based on their historical

[13] *See* fn.3, supra.

performance in last three Planning Years. The proposed two-step accreditation process no longer requires the system wide UCAP to ISAC conversion ratios to scale the ISAC values.

Q. WHY DID MISO REMOVE THE SYSTEM-WIDE UCAP TO ISAC CONVERSION RATIO IN SCHEDULE 53A?

A. The system wide UCAP to ISAC conversion ratio was put in place to ensure SAC was aligned with how requirements were determined during the probabilistic analysis. In other words, it brought accreditation into the same terms or currency as the requirements. MISO's proposed accreditation methodology naturally aligns accreditation with requirements since both are produced from the same probabilistic model. Therefore, there is no longer a need for the system wide UCAP to ISAC conversion ratio. As a result, MISO decided to adjust the language in Schedule 53A to better describe the process to establish the final SAC value for each resource. The proposed Tariff language aligns with the two-step process described above.

Q. HOW DID MISO ESTABLISH THE PROPOSED RESOURCE CLASSES?

A. The proposed Tariff includes general criteria for determining Resource Classes as well as establishing the specific Resource Classes that will initially apply. MISO considered the operating characteristics, technology, fuel type, and the expected performance of resources in its forward-looking probabilistic model to evaluate the criteria for defining Resources Classes. Ultimately, MISO decided to establish Resource Classes based on similar operating characteristics of individual resources within the class and generally reflect the same or similar technologies. The specific Resource Classes are: Gas (including oil), Combined Cycle, Coal, Hydro, Nuclear, Pumped Storage, Solar, Wind, Storage, Run-of-River, and Biomass. These Resource Classes each possess unique properties that

differentiate themselves from one another and produce a complete set of classes into which each resource can be uniquely assigned. Although Resource Classes are being defined in the Tariff with this filing, MISO intends to periodically review the set of Resource Classes and work with Stakeholders on any proposed changes before making a Tariff filing that would update the defined Resource Classes.

Q. DID MISO CONSIDER COMBINING ALL THERMAL RESROUCES INTO A SINGLE RESOURCE CLASS?

A. Yes. MISO evaluated combining all thermal resources into a single Resource Class. However, MISO decided not to pursue this approach for three reasons. First, there is a significant disparity in the operating characteristics of the different types of thermal resources during various weather events (e.g. cold weather snaps affect Gas resources differently than Nuclear resources). Second, thermal resources are appropriately modeled differently in the probabilistic analysis corresponding to their respective operating characteristics (e.g. Coal, Gas, and Combined Cycle resources have a cold weather outage adder modeled in MISO's probabilistic analysis). Third, such an approach will not provide the appropriate signals to inform retirement and investment decision making with respect to specific Resource Classes, which is one of the primary objectives of the proposed reforms.

Q. HOW WILL MISO DETERMINE WHETHER THE LIST OF RESOURCE CLASSES NEEDS TO BE UPDATED?

A. MISO will continue to monitor its generator interconnection queue, and the changes in its generation fleet to evaluate if the proposed Resource Classes established in the Tariff (Schedule 53A) need to be updated. MISO will also work with stakeholders to determine

whether additional Resource Classes should be established in the future as new technologies emerge and as MISO gains experience with the performance of resources under the DLOL-based methodology.

Q. HOW DOES MISO ENSURE THAT THE PERFORMANCE OF A SINGLE RESOURCE IN THE PROBABILISTIC MODEL DOES NOT UNDULY INFLUENCE THE RESOURCE CLASS-LEVEL UCAP FOR SMALL RESOURCE CLASSES?

A. MISO acknowledges that a single resource can theoretically unduly influence the Resource Class-level UCAP of a small Resource Class. MISO has evaluated preliminary results calculated using the probabilistic model for Planning Year 2023 – 2024 to determine how individual resources in a small Resource Class may impact the Resource Class-level UCAP. For small Resource Classes, particularly Nuclear and Pumped Storage, each resource's modeling and assumptions within the class were consistent in the probabilistic analysis relative to the other resources within the class.

Nevertheless, MISO is planning to establish a quality control/quality assurance (QA/QC) procedure in the Resource Adequacy Business Practices Manual that will track year-over-year changes for the main parameters that determine the performance of each resource in the probabilistic model (e.g., forced outages rates or maintenance rates for thermal units). If this QA/QC check determines that a single resource is unduly influencing the Resource Class-level UCAP, MISO will address the modeling of such resource and/or Resource Class-level UCAP calculations for the corresponding Resource Class on a case-by-case basis.

Q. CAN AN INDIVIDUAL RESOURCE HAVE A HIGHER SAC, AS A PERCENTAGE OF ICAP, THAN THE RESOURCE CLASS-LEVEL UCAP, AS A PERCENTAGE OF ICAP?

A. Yes, some individual Resources will perform better than the Resource Class when comparing their SAC as a percentage of their ICAP if they have better historical performance relative to other resources within their Resource Class. The only situation in which all resources in a Resource Class would have their SAC as a percentage of their corresponding ICAP match the Resource Class-level UCAP to the Resource Class-level ICAP percentage is if all the resources have the exact same behavior during Tier 1 and Tier 2 RA Hours, so that their individual ISAC values are all proportional to ICAP. In all other situations, some individual resources will perform better, and some will perform worse than the Resource Class average. As illustrated by way of the example in Figure 9 above, the Resource Class-level UCAP percentage is 67% of Resource Class-level ICAP, but individual resource SAC values range from 52% to 85% of their respective ICAP values.

Q. HOW WILL PLANNED OUTAGES AFFECT RESOURCE CLASS-LEVEL UCAP?

A. Planned outages are modeled using maintenance rates for each resource in the probabilistic model. Planned outages will reduce capacity availability of Resource Classes within the probabilistic model and commensurately reduce accreditation. By incorporating planned outages, the model will appropriately make resources unavailable to meet load for a period that correlates with their historic average maintenance rates, and along with other resources' availability in the model provides an overall picture of the Resource Class's availability in the probabilistic model. Recognizing planned outages in the probabilistic

model is essential to identify periods of reliability risks and allows the simulated outcomes to better reflect expected availability of resources, especially given that MISO has implemented a seasonal resource adequacy construct. Accounting for planned outages in Resource Class-level UCAP calculations will ensure each Resource Class's contribution to reliability is appropriately accounted for and the approach is aligned with the key objectives of resource accreditation.

Q. HOW ARE ACTUAL PLANNED OUTAGES IN THE RECENT PAST ACCOUNTED FOR IN THE ISAC CALCULATION OF INDIVIDUAL RESOURCES?

A. MISO essentially is leveraging the existing planned outage exemption process that is used for the calculation of ISAC for all Schedule 53 Resources. Under MISO's proposed accreditation methodology, exemptions will also be granted for planned outages as described in Schedule 53A and in MISO's Business Practice Manual (BPM) for Outage Operations. Without an exemption, a planned outage is treated like any other outage and a resource receives zero (0) credit of availability for that hour. With an exemption, the availability of a resource will be calculated by multiplying the seasonal Resource Class-level UCAP as a percentage of Resource Class-level ICAP by the resource's ICAP instead of a zero (0) for that hour during the exempted planned outage. As set forth in Schedule 53A, however, solar resources will not receive planned outage exemptions at night. The specific hours for this exception will be provided in MISO's Business Practices Manual for Resource Adequacy and will be Local Resource Zone (LRZ) and local time specific, in such a way that any daytime operating hour interval will allow for an exemption. As an example, if the sun sets at 20:01, then an exemption will be allowed for

the hour beginning at 20:00. If the sun rises at 06:59, then there will be an exemption allowed for the hour beginning at 06:00 hour. However, no exemption would be provided in this example for a solar resource planned outage scheduled to take place between 21:00 hours and 06:00 hours.

Q. WHY ARE EXEMPTIONS FOR PLANNED OUTAGES APPROPRIATE FOR CALCULATIONS USING THE DETERMINISTIC APPROACH BUT NOT FOR RESOURCE CLASS-LEVEL UCAP CALCULATIONS USING THE PROBABILISTIC APPROACH?

A. Exemptions for planned outages under current Schedule 53 provide an incentive for resource owners to plan outages for their resources in advance and at times most beneficial to operational reliability. Exemptions are also only used to allocate the Resource Class-level UCAP to the individual resources within the Resource Class. This provides an incentive for resource owners with resources within each Resource Class to plan their outages well in advance because they will receive a bigger slice of the overall Resource Class-level UCAP compared to resources within the class that do not plan their outages well in advance. Applying exemptions for planned outages in the prospective probabilistic analysis under Schedule 53A, which is used to calculate Resource Class-level UCAP, would be inappropriate because the probabilistic model needs to identify all possible risks that may impact the reliability of the system. All outages need to be captured to ensure target system reliability is maintained. A planned outage increases the probability of reliability risk being present and this risk should not be ignored in the establishment of a resource's contribution to reliability and determination of Resource Adequacy Requirements. Therefore, for the planning horizon an exemption for a planned outage is

inappropriate while over the operating horizon an exemption is appropriate and improves reliability through prudent outage planning. MISO's operations and outage coordination groups have already started seeing changes in outage scheduling patterns and have also begun to realize some of the associated benefits through the implementation of Schedule 53 outage exemption rules effective for Planning Year 2023 - 2024.

Q. IS THERE A RISK OF "DOUBLE COUNTING" BECAUSE PLANNED OUTAGES ARE CONSIDERED IN THE RESOURCE CLASS-LEVEL UCAP CALCULATIONS AND IN THE CALCULATION OF AN INDIVIDUAL RESOURCE'S ISAC?

A. No. Although planned outages are included in each step of the two-step proposed accreditation process, they are treated differently by design. As described in the two-step process above, Resource Class-level UCAP determines the size of the pie and individual resource ISAC will determine how that pie is split up. The fact that planned outages are included in the two calculations has no bearing on the result because the ISAC is merely used to determine how much of the Resource Class-level UCAP each resource in the Resource Class will receive. All resources within the class are treated the same in regard to outages in their ISAC calculation. Additionally, properly planned resource outages are eligible to receive an exemption for purposes of the ISAC calculation pursuant to Schedule 53A. Providing this exemption for properly planned outages is a mechanism to encourage Market Participants to minimize the number of planned outages during expected periods of highest reliability risk. Resources that plan their outages well in advance will receive a larger portion of the Resource Class-level UCAP. For these reasons, planned

outages are not double-counted in either the Resource Class-level UCAP or ISAC calculation.

Q. SHOULD CRITICAL HOURS IDENTIFIED IN THE LOLE MODEL BE EXPECTED TO MATCH RESOURCE ADEQUACY HOURS THAT ARE USED TO ALLOCATE RESOURCE CLASS-LEVEL UCAP TO INDIVIDUAL RESOURCES?

A. No. As explained previously, the proposed accreditation methodology is a balanced approach that captures a range of reliability risks in both the planning and operations horizons by incorporating forward-looking probabilistic analysis with a resource's actual performance during recent periods of high system risk. By design, therefore, perfect alignment between Critical Hours and RA Hours is not expected. Critical Hours identified in the probabilistic model include a wide range of system conditions (e.g., 30 years of weather data, five different load forecast errors, and hundreds of random outage draws). On the other hand, the three years of operational data used to determine RA Hours represent a limited number of snapshots of different system conditions that were experienced operationally. It is also important to note that Tier 1 and Tier 2 RA Hours are only used to distribute the Resource Class-level UCAP to individual resources and every resource in the Resource Class and Planning Region will utilize the same set of hours.

Also, it is important to note that results from the probabilistic analysis are not expected to and should not exactly match results of the deterministic approach. As indicated previously in my testimony, one of the benefits of the proposed approach is that it disentangles random factors that may have occurred historically from the expected performance characteristics

of a resource and Resource Class under the wide variety of events that are captured in the probabilistic model.

Q. WHY ARE SOLAR RESOURCES TREATED DIFFERENTLY REGARDING SCHEDULE 53A PLANNED OUTAGE EXEMPTIONS?

A. Exemptions are provided to incentivize minimizing the number of planned outages in any given hour. To receive an exemption, a resource generally must plan the outage to occur at least 120 days in advance. Solar is a unique resource where knowledge of fuel unavailability (i.e., when the sun will rise and set) is known 120 days in advance. For other resources, such as wind or gas, fuel unavailability cannot be predicted 120 days in advance. Therefore, there is the ability for solar resource owners to claim exemptions when they know they cannot provide energy. Allowing solar resources to receive an exemption for planned outages taken during night-time hours, and thereby receiving the corresponding seasonal Resource Class-level UCAP value as a percentage of the Resource Class-level ICAP, would distort the accredited capacity value of such solar resources as they appear to be available when it would otherwise be impossible to inject energy into the grid.

Q. HOW IS MISO PROPOSING TO ACCREDIT HYBRID AND CO-LOCATED RESOURCES?

A. Co-located resources that share an interconnection service limit will be accredited according to each of the resources' chosen participation model and their accreditation would equal the sum of the individual components. For example, co-located solar and storage resources will be accredited under the solar and storage Resource Classes, respectively. Because the resources share an Interconnection Service Limit, though, their total Intermediate SAC will be limited by that Interconnection Service Limit since the

combined set of resources cannot deliver MWs above that limit. Resource-level metering and sum of the parts accreditation for co-located resources allows for proper resource accreditation for each potential combination while accounting for a shared interconnection constraint. Even if separate component capabilities could exceed the interconnection service limit, the interconnection limit provides a total upper bound on possible contributions for each interconnection agreement.

Given the above, MISO proposes accrediting single-offer hybrid resources according to their chosen participation model. For example, a solar plus storage hybrid resource operating as a solar Dispatchable Intermittent Resource (DIR) will be accredited under the Solar Resource Class. Creating an accreditation Resource Class for hybrid resources is potentially intractable given the countless combinations of resources that could make up a hybrid resource. Moreover, creating different Resource Classes for each hybrid combination is unmanageable. Solar and storage resources in combination can have significantly different operating characteristics such that a single class for this fuel-type combination would not be meaningful (e.g., differing storage and solar capacity ratios, DC- or AC-coupled design, grid charging or non-grid charging).

Q. ARE LOAD MODIFYING RESOURCES (LMR) INCLUDED IN MISO'S ACCREDITATION REFORM PROPOSAL?

A. No, the proposed methodology does not apply to LMRs. MISO will continue to determine LMR accreditation through the current methods, derived from their past performance (forced outage rates for Behind the Meter Generation LMRs, and testing documentation submitted to MISO for Demand Resource LMRs), as provided in the Business Practice Manual for Resource Adequacy. MISO is currently engaging with stakeholders through its

RASC to improve the accreditation methodology for LMRs, but that effort is separate from the proposed accreditation methodology discussed in this testimony. MISO expects to make a separate filing for LMR accreditation reforms in the future after the design for the proposed changes is final and discussed with the stakeholders.

Q. WHAT IS MISO'S PLAN FOR ACCREDITING EXTERNAL RESOURCES?

A. MISO will continue to accredit External Resources through the current methods, which are derived from historical forced outage rates. Hourly real-time availability data is not currently collected for External Resources as these resources do not participate in MISO markets analogously to other resources. Because External Resources do not participate in the same manner as resources internal to MISO, they are also being treated differently here. MISO will evaluate methods to move all resources, including External Resources, under the proposed methodology in the future.

V. RESOURCE ADEQUACY MODELING

Q. WHAT IS THE LINK BETWEEN MISO'S PROBABILISTIC MODEL AND THE PROPOSED ACCREDITATION METHODOLOGY?

A. The probabilistic model is at the heart of MISO's proposed accreditation methodology because resource accreditation and Resource Adequacy Requirements will be directly determined using the same probabilistic model. Because the probabilistic model is central to the proposed accreditation methodology, I will briefly describe certain aspects of that model in this section of my testimony. Further information on MISO's probabilistic model

is available on MISO's website on the Resource Adequacy page and the Loss of Load Expectation Working Group page.[14]

Q. PLEASE BRIEFLY DESCRIBE THE PROBABILISTIC MODEL USED BY MISO IN ITS RESOURCE ADEQUACY CONSTRUCT.

A. MISO uses Astrapé's Strategic Energy Risk Valuation Model (SERVM) software to conduct the LOLE analysis. The SERVM software uses a sequential Monte Carlo simulation to step through time chronologically on an hourly basis and considers many combinations of random system conditions to evaluate how often system load can be covered by resources. The random system conditions include features such as planned and forced outages at the resource-level, import availability from neighboring system, as well the representation of 30 years of correlated load and other weather-dependent datasets, such as wind or solar generation and cold-weather outages.

Aside from assumed future capacity additions, typically only Capacity Resources that have cleared the most recent PRA are considered in the model. The probabilistic model data is generally updated on a yearly basis. Enhancements to modeling inputs and assumptions are constantly incorporated, based on the needs identified for the MISO footprint, new developments, industry best-practices, and stakeholder feedback.

Q. HOW HAS THIS MODEL PREVIOUSLY BEEN USED FOR MISO'S PRA?

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[14] *See* MISO's Resource Adequacy site, available at: https://www.misoenergy.org/planning/resource-adequacy2/resource-adequacy/#t=10&p=0&s=FileName&sd=desc

See MISO's Loss of Load Expectation Working Group site, available at: https://www.misoenergy.org/engage/committees/loss-of-load-expectation-working-group/

A. MISO has performed LOLE analysis using a probabilistic model for more than fifteen years, and has used the current software, SERVM, since 2015 in establishing Resource Adequacy Requirements (both PRMR and LRR). MISO's probabilistic model has also been used to perform the studies that determine the seasonal capabilities of wind and solar resources for the determination of requirements, as well as to accredit wind resources that plan to participate in the PRA. The proposed accreditation methodology will improve the alignment between accreditation and requirements in the MISO RA construct. MISO will continue to use the probabilistic model to set Resource Adequacy Requirements and will expand the use of the model to establish Resource Class-level UCAP.

Q. PLEASE EXPLAIN LOLE.

A. As discussed above, LOLE is the measure of how often, on average, the probabilistic model experiences days in which resource availability falls short of the load demand. LOLE is a commonly used metric in the electric industry, particularly in North America, to measure the expected frequency of resource adequacy events in a year, a season, or any other pre-defined period. As part of the LOLE analysis process, MISO calculates the following three probabilistic risk metrics:

- LOLE, which measures the frequency (in days) of load shed events;
- Loss of Load Hours (LOLH), which measures the expected number of hours per year expected to experience load shed events; and
- Expected Unserved Energy (EUE), which is an estimate of the energy that would otherwise have been used by end use customers but for a supply interruption during a predefined period (e.g., a year).

Q. PLEASE DISCUSS THE LOLE CRITERION TO WHICH MISO PLANS.

A. The MISO Resource Adequacy criteria for determining the Planning Reserve Margin Requirements is the industry-accepted LOLE objective of 1 day in 10 years on an annual basis. This LOLE criterion is also used by other ISOs, including NYISO and PJM, as discussed in their recent accreditation filings. Commencing with implementation of MISO's seasonal PRA in the Planning Year 2023-24, MISO evaluates LOLE for each Season and establishes corresponding seasonal Planning Reserve Margins. The seasonal LOLE analysis is determined as follows:

a) the system is adjusted until the annual LOLE reaches 1 day in 10 years;

b) the seasonal distribution of annual LOLE values is measured ;

c) any Season with a LOLE value below 0.01 is further adjusted until the LOLE in that Season reaches that value; and

d) any Season with a LOLE value at or above 0.01 receives the adjustment to capacity that drives that annual LOLE to 1 day in 10 years.

In the most recent LOLE analysis, most of the annual LOLE has been concentrated in the Summer Season, and all other Seasons had to be adjusted to meet the minimum of 0.01 LOLE.

Q. PLEASE DISCUSS THE LOLE MODEL INPUTS.

A. There are three broad categories of LOLE model inputs: load, generation resources, and system parameters. Load inputs consist of a demand and energy forecast, and load forecast errors. Generation inputs include operating parameters, unit forced outage rates, planned maintenance rates, hourly generation level for variable renewable resources, and dispatch

limits for demand response and interruptible load. System parameter inputs include zone and pool definitions, external tie limits, and external system energy imports.

Q. PLEASE DISCUSS HOW MISO MODELS LOAD IN ITS LOLE ANALYSIS.

A. MISO develops hourly load profiles that are used in the simulation of the probabilistic models. To ensure a representation of a wide range of system conditions, 30 load profiles are created, based on observed weather for the last 30 weather years, primarily driven by temperature values. The process to create the load data profiles can be summarized as follows:

MISO uses the previous 5 years of historical load data with Load Modifying Resource load reductions added back into the load, as an input to train a neural-net model to predict weather-correlated load shapes for each of these 30 weather years.

MISO also performs validations and corrections on the predicted neural-net load shapes to ensure proper load shape and peak values. This training allows the model to evaluate the risk that could materialize in the upcoming Planning Year if similar weather patterns were to be experienced again.

MISO applies the Zonal Coincident Peak Forecasts provided by the Load Serving Entities to develop zonal- and monthly-specific load forecast scaling factors which scale the average of the 30 load shapes based on provided forecasts.

This procedure creates hourly load profiles for the 30 weather years, which are consistent with expected load forecasts. During the LOLE simulations, each load profile is further adjusted to account for economic load uncertainty using economic load forecast error (LFE) scalars, resulting in five load profiles for each weather year. These include the expected load profiles, plus an increase of the load by ±1% and ±2%. Corresponding

probabilities are assigned to each load forecast error level, which are published by MISO every year. These probabilities can vary depending on the Planning Year. For example, the probabilities for Planning Year 2023-2024 were previously provided in Section IV. The 30 years of load data are also provided to Market Participants by MISO prior to the beginning of each Planning Year.

Q. PLEASE DISCUSS HOW MISO MODELS GENERATION IN ITS LOLE ANALYSIS.

A. MISO uses data from several different sources to model generation in its LOLE analysis. MISO begins with its annual, base Commercial Model and uses eligible capacity as determined by the annual PRA. Thermal units are modeled as must-run and perform at their full capacity whenever units are not on outage. The primary data source for forced outage rate statistics, planned maintenance statistics, and net dependable capacity (NDC) for monthly capacity profiles are obtained from the Generator Availability Data System (GADS).

Retirements are accounted for based upon the Attachment Y process in the MISO Tariff, while new resources are included based upon their position in the Generator Interconnection Queue. Imports are modeled based on firm capacity contracts from external areas to serve MISO load, as well as a probabilistic distribution of non-firm support from external areas.

MISO models wind and solar resources using hourly output profiles that reflect their variable nature. Each of the 30 weather years modeled have a unique hourly output for wind and solar resources to align with the load profiles which are described in more detail

below. Prior to each Planning Year, MISO shares the 30 weather years of hourly data for wind and solar resources with Market Participants.

Other renewable resources, like run-of-river and biomass are modeled at a flat capacity value.

Q. DOES MISO CONSIDER HOW COLD-WEATHER OUTAGES IMPACT GENERATION IN ITS LOLE ANALYSIS?

A. Yes, Astrapé, the entity that manages the SERVM software used for LOLE analysis, performed an analysis showing that as the temperatures decreased, the average megawatts (MW) of forced outages for coal and gas resources increases.[15] Based on that analysis, a MW/degree relationship was developed and modeled so that at each temperature, there is a specific MW amount of incremental cold weather outage captured for each zone. The incremental cold weather outages are not assigned to a particular resource but rather represent the aggregate Resource Class-level impact on the system to the Coal, Gas, and Combined Cycle Resource Classes.

Q. HOW ARE WIND RESOURCES SPECIFICALLY MODELED IN THE LOLE MODEL?

A. MISO models wind resources with hourly generation profiles for each of the 30 weather years. Profiles from 2013 and on use observed historical data, aggregated by LRZ. Minor increases to the profile are included from 2013 to 2015 to account for technology improvements as detailed in the Astrapé Seasonal Inputs Study.[16] Synthetic profiles are

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[15] Section 5 of the report available at 20220707 LOLEWG Supplemental MISO Seasonal Inputs Documentation Astrape625466.pdf (misoenergy.org).

[16] Astrapé Seasonal Inputs Study: Astrapé Seasonal Inputs Study.

generated for each LRZ and weather year prior to 2013 by choosing wind output from the observed days based on (a) the maximum daily temperature in the April through October months, and (b) the minimum daily temperature during November through March. The temperature to provide a match is aggregated at the LRZ level.[17]

Q. HOW ARE SOLAR RESOURCES SPECIFICALLY MODELED IN THE LOLE MODEL?

A. Solar generation profiles are created in a similar fashion to that for the wind resources. First, hourly irradiance data for sites across the MISO footprint are downloaded from the National Renewable Energy Laboratory's (NREL's) National Solar Radiation Database (NSRDB). The irradiance data is converted to hourly power generation data using NREL's System Advisory Model software. Given that the NREL irradiance data is only available starting with year 1998, data for prior weather years are developed by selecting daily solar profiles from the day that most closely matched the peak temperature out of all days ($\pm$ 6 days) from the available data.

Q. HOW ARE STORAGE RESOURCES MODELED IN THE LOLE MODEL?

A. Storage resources are treated as energy-limited resources in the LOLE model. Pumped storage resources are currently modeled with seasonalized forced outage rates, an annualized planned outage rate, and monthly capability. Electric Storage Resources have a

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[17] This matching procedure begins by matching a day prior to 2013 to the same calendar day for a year that is observed, where the matching occurs if the temperatures on the two dates are equal. If they are not equal, the previous and subsequent calendar date is evaluated. This continues until a band of $\pm$10 days has been searched. If no matches have occurred, the temperature is allowed to be different by 1°, and the search repeats. For example, for April 11th, 1998, the dates April 11th, 2013, April 11th, 2014, and so on are evaluated. If one of these days has the same max temperature as the 1998 year, then the wind profile from that matched day is used. If not, April 10th and April 12th are evaluated. This continues until a range encompassing April 1st through April 20th has been searched.

4-hour duration with a cycle efficiency of 85% and a maximum hourly output value determined by the capacity of the individual resource. Electric Storage Resources are dispatched in the model when load cannot be served by other resources (except emergency resources). The probabilistic model keeps track of the stored energy in these resources and will allow generation until the energy is exhausted. At that point, the storage resources will need to replenish its stored energy before they are available for dispatch in the model.

As a part of its LOLE modeling enhancements effort, MISO intends to continue working with stakeholders to evaluate how the modeling of storage resources in the LOLE model needs to be adjusted to reflect how they are being operated in the operational time frames or real time markets, and how their energy-limited nature may influence the determination of risk across simulated hours.

Q. HOW DOES MISO CONDUCT EXTERNAL SUPPORT MODELING FOR THE LOLE ANALYSIS?

A. Firm imports from the most recent PRA are included in the LOLE analysis and modeled as resources. In addition, MISO models non-firm imports as a probabilistic distribution based on historic imports from the most recent 3 planning years. As the model steps through the simulated hours, it randomly draws from this distribution of imports to serve the demand. Non-firm imports reduce the PRMR, which results in MISO relying on neighboring regions to serve some of its demand. Historic non-firm imports during historical Tier 2 RA hours are used to create a probabilistic distribution of non-firm support. This process is completed for each of the four Seasons to capture seasonal variability. As SERVM steps through the hourly Monte Carlo simulations, the model will randomly draw import values from seasonal distributions.

Q. WHY IS IT REASONABLE TO RELY ON THE CURRENT PROBABILITIC MODEL TO DETERMINE RESOURCE CLASS-LEVEL UCAP?

A. MISO has relied on a probabilistic model to determine the Resource Adequacy Requirements for over 15 years. Over that time, MISO has continually improved the underlying modeling and input data, incorporating best practices as they are developed by the industry and in collaboration with stakeholders. Use of MISO's current probabilistic model is therefore fully appropriate to be applied to the proposed DLOL-based accreditation methodology.

MISO is committed to further the evolution of the probabilistic model as this is both necessary and appropriate to better capture the changing composition of the Bulk Electric System and to continually improve the representation of the sources of system risk. MISO has communicated a plan to stakeholders to research, design, and implement specific aspects of the probabilistic model, including a revision of planned outages, cold-weather outages, load forecasting, and storage modeling.[18] The planned model enhancements will further refine that alignment between risk, needs, and availability, as will other additional improvements made in the future.

VI. DEVELOPMENT OF THE PROPOSED METHODOLOGY

Q. PLEASE PROVIDE AN OVERVIEW OF THE PROCESS MISO USED TO DEVELOP THE ACCREDITATION PROPOSAL THAT IS THE SUBJECT OF THIS FILING.

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[18] *See* 20240228 RASC Item 05c RA Model Enhancement Presentation631891.pdf (misoenergy.org)

A. In January 2022, following MISO's Seasonal Construct and SAC filing, MISO initiated a stakeholder process through the RASC to work with stakeholders to develop the resource accreditation reform that is the subject of this filing. MISO has followed the product development process shown in Figure 10 below. The goal of the product development process is to ensure the right solutions are built at the right time and solve the right issues. MISO began by defining the scope of the initiative, which included drafting a problem statement. Once the problem statement and scope were defined, MISO began evaluating potential solutions and ultimately recommended the proposed accreditation methodology that is the subject of this filing. From there, MISO began working through and refining the conceptual design. Once that process was complete, MISO made this filing with the Commission and, if accepted, will implement the proposed accreditation methodology for Planning Year 2028-2029. Pursuant to the proposed Schedule 53A, during the three-year period leading up to actual implementation, MISO will provide stakeholders with indicative information about expected Resource Class and resource level accreditation values to assist state regulators and LSEs with integrated resource planning.



Figure 10: MISO Product Development Process

Q. WHAT IS THE PROBLEM STATEMENT THAT MISO DEVELOPED IN COLLABORATION WITH THE STAKEHOLDERS AT THE BEGINNING OF THE ACCREDITATION REFORM EFFORTS?

A. The resource accreditation reform problem statement was first presented to stakeholders at the January 2022 RASC meeting. Stakeholders were provided an opportunity to comment on the problem statement, but generally agreed with it as presented. The problem statement has essentially remained the same and remains the focus of the resource accreditation reform effort. The problem statement is:

Resource accreditation should reflect the availability of resources when they are most needed. Significant growth of variable, energy-limited resources in the MISO footprint, along with changing weather impacts and operational practices, are shifting risk profiles in highly dynamic ways with implications to Resource Adequacy and planning. MISO's existing accreditation methods for non-thermal resources require further evaluation to ensure that the accredited capacity value reflects the capability and availability of the resource during the periods of highest reliability risk.

Q. WHAT IS THE SCOPE OF MISO'S RESOURCE ACCREDITATION REFORM EFFORT?

A. The scope of the accreditation reform as identified at the January 2022 RASC was to revisit the established accreditation practices for non-thermal resources with a priority focus on those with the greatest reliability impact in the near-term (i.e., wind and solar). In response to stakeholder feedback concerning comparability between resources and the Commission's comments in response to MISO's Seasonal Resource Adequacy Construct and SAC filing, MISO recommended extending the scope of the resource accreditation

reform effort to cover additional accreditation changes for all Capacity Resources (excluding external resources) at the January 2023 RASC.

Q. WHY DID MISO RECOMMEND EXTENDING THE SCOPE OF ACCREDITATION REFORM TO INCLUDE ALL CAPACITY RESOURCES AND NOT JUST NON-THERMAL RESOURCES?

A. The methodology developed for non-thermal resources was resource type agnostic and found to be applicable to all resources in the MISO footprint. This provided several advantages: (a) it does not discriminate based on resource type, which allows all Schedule 53A Resources to be treated equally, (b) it improves consistency and efficiency by bringing the entire accreditation process under one probabilistic modeling effort compared to many different methods under the existing process, (c) it provides alignment between the determination of the need (requirements) and availability of resources (accreditation) by ensuring both processes are performed with the same information and model, (d) it improves the thermal accreditation process by including new sources of risk, such as correlated and coincidental risks and weather-dependent derates, and (e) it allows for reliability-neutral substitution between resource types.

Q. WHAT WAS MISO'S APPROACH TO EVALUATING ACCREDITATION METHODOLOGIES?

A. MISO approached the evaluation of accreditation reform by examining a wide range of possible methods to address the problem statement. The evaluated methodologies for accreditation can be broadly divided into two categories: 1) average accreditation approach, such as average ELCC, and 2) marginal accreditation approach, which includes marginal ELCC, marginal reliability improvement (MRI) and DLOL. MISO developed

evaluation criteria and an analysis framework to compare modeling results and help guide decisions on which method was best for the MISO footprint. This larger list of options was ultimately reduced to a smaller set of three options that were examined in quantitative analysis and discussed with MISO stakeholders: ELCC method, a fully deterministic method, and blended method.

Q. WHAT CRITERION DID MISO CONSIDER WHEN EVALUATING ACCREDITATION METHODOLOGIES?

A. MISO evaluated accreditation methodologies against the following five general criteria: impact, feasibility, flexibility, stability, and, after receiving feedback from stakeholders, comparability. These were developed based on criteria previously used for the Resource Availability and Need (RAN) initiative, presented at the October 2020 RASC, and modified based upon stakeholder input. These criterion are all related to the "pillars of accreditation" identified by the Energy Systems Integration Group (ESIG).[19]

Q. PLEASE DISCUSS THE IMPACT CRITERION.

A. A method's impact is identifying and sufficiently mitigating actual risk under current and future portfolios and grid conditions in conjunction with markets and operations. Impact ensures sufficient capacity in the planning horizon when it's needed to maintain reliability. The method should measure performance in scarcity conditions and link planning to operations. This criterion is related to the reliability pillar identified by ESIG.

[19] Energy Systems Integration Group, "Ensuring Efficient Reliability: New Design Principles for Capacity Accreditation" (2023), available at: https://www.esig.energy/new-design-principles-for-capacity-accreditation/.

Q. PLEASE DISCUSS THE FEASIBILITY CRITERION.

A. Feasibility is the practicality, scalability, and ability of MISO and its Market Participants to implement the proposed methodology. The feasibility criterion also takes into consideration the clarity and transparency of the process. Both MISO and Market Participants need to be able to reasonably predict the expected accredited values of resources to ensure a reliable resource mix and make appropriate investment and retirement decisions. The feasibility criterion is rooted in the transparency pillar identified by ESIG.

Q. PLEASE DISCUSS THE FLEXIBILITY CRITERION.

A. Flexibility is a measure of how robustly a method holds up over time and responds to a changing system portfolio. As the resource portfolio evolves and technologies develop that change the load profile, an accreditation methodology needs to remain relevant and capable of properly accrediting resources. Without this flexibility, a system becomes in danger of mis-accrediting capacity values potentially leading to system reliability risks and an inefficient allocation of resources. This criterion is tied to the robust pillar identified by ESIG.

Q. PLEASE DISCUSS THE STABILITY CRITERION.

A. Stability is the ability to reasonably inform state and utility resource planning processes that rely on accreditation information as an input to long-term decision making. The method should not only remain robust under changing conditions but should be able to reflect changing conditions as system resource mix and load profiles evolve. Finally, these capacity values should remain predictable over time and only move when structural changes to the system have occurred which shift risk and alter the generation profile of the fleet. Greater volatility in capacity accreditation leads to lower investments as decision

makers face greater risk. A method that minimizes accreditation volatility increases investment certainty resulting in a more efficient system. This criterion aligns with the predictable pillar identified by ESIG.

Q. PLEASE DISCUSS THE COMPARABILITY CRITERION.

A. The comparability criteria refers to how comparable two different resource class accreditation values are to one another. Utility planners should be able to directly compare one resource class to another across a broad range of factors to make the most efficient investment and retirement decisions. A methodology that makes comparison between resource classes difficult may result in a less efficient and riskier resource portfolio. Conversely, a methodology that allows for comparability makes investment and retirement decisions easier to analyze and provides an accurate measure of the marginal cost and benefits associated with different amounts of different resource classes. This criterion is related to the non-discriminatory pillar identified by ESIG.

Q. PLEASE DESCRIBE THE ELCC METHOD.

A. The ELCC method belongs to a class of accreditation methodologies that determine capacity values based upon a probabilistic assessment of availability during loss of load hours. MISO analyzed two different types of ELCC methodologies. The first method, average ELCC, determines accreditation for each resource class by first modeling the system at the LOLE target criteria. Next, the resource class of interest is removed from the system and perfect capacity is added until the model returns to criteria. The amount of perfect capacity added is the accredited value of the class and referred to as the ELCC MW. This option is currently used at MISO for wind resources and served as the reference case. The second method, marginal ELCC, is identical in procedure to the average ELCC

approach, except instead of removing a resource class, an incremental resource is removed (or added) to the system.

Q. PLEASE DESCRIBE THE DETERMINISTIC METHOD CONSIDERED.

A. The deterministic method considered would have measured accreditation using only historical performance. This approach could take several forms, such as applying only the Schedule 53 Tier 1 and Tier 2 RA hours framework, relying upon historical GADS data, or some other strictly backward-looking approach based upon historical resource performance. This method is conceptually similar to how thermal units are currently accredited.

Q. PLEASE DESCRIBE THE BLENDED METHOD.

A. The blended method combines a probabilistic and deterministic approach. Each of the two approaches has its merits and shortcomings. A probabilistic approach allows for the expected capacity value of a resource to be estimated under a broad range of conditions. However, the quality of this assessment is limited by the standard modeling limitations, namely quality of the inputs and the model. Deterministic approaches have the advantage of demonstrating what has occurred and do not rely upon a model to calculate. Their drawback is that what happened yesterday may not accurately reflect what may happen tomorrow. If there are structural differences in events that are not captured, then a backwards-looking only framework may fail to properly realize the value of a resource and create improper incentives towards investment and retirement decisions.

The blended method attempts to merge these two perspectives into a single view and capitalize on each method's strengths while minimizing each method's weaknesses. With a blended method, accreditation would be based upon expected performance during

projected probabilistic risk periods as well as historical performance. Additionally, proper signals can be sent in both the operational and planning horizons by tying accreditation to both periods. Resource owners are rewarded for improving the operation of their units from the deterministic portion of the accreditation while sending more reliable signals about which assets to invest in or retire based upon the probabilistic portion.

Q. WHAT ACCREDITATION METHODOLOGY IS MISO PROPOSING?

A. MISO has chosen a blended approach combining a probabilistic approach, capacity values determined through the probabilistic modeling (the first step in the proposed DLOL-based methodology), with a deterministic approach, historical performance measured by the proposed Schedule 53A Tier 1 and Tier 2 RA hours for all Capacity Resources, excluding External Resources.

Q. WHEN WEIGHING THE IMPACT CRITERIA, EXPLAIN HOW MISO DECIDED TO RECOMMEND THE PROPOSED APPROACH.

A. MISO's proposed methodology identifies expected risk by accrediting resources during periods when the system is at highest risk, as measured by the margin between generation and load in the probabilistic model. The identification of these risky periods is independent of the resource portfolio. Because availability during Critical Hours is used to set Resource Class-level UCAP, the method naturally measures performance during scarcity conditions. Further, it also uses historical performance to establish capacity values and therefore incentivizes resources to perform in a manner that increases system reliability. Therefore, it links planning to operations and provides the greatest impact of the options considered.

Q. WHEN WEIGHING THE FEASIBILITY CRITERION, EXPLAIN HOW MISO DECIDED TO RECOMMEND THE PROPOSED APPROACH.

A. The proposed methodology uses a single probabilistic model run to set Resource Class-level UCAP and Resource Adequacy Requirements, limiting the computational complexity of the required calculations. It can be implemented in the same manner no matter the size of the resource portfolio, which gives it scalability. With similar input data, MISO and Market Participants could implement and replicate results. This feasibility allows for the ability for efficient investment and retirement decisions to be made with confidence that the projected accreditation values would be realized.

Q. WHEN WEIGHING THE FLEXIBILITY CRITERION, EXPLAIN HOW MISO DECIDED TO RECOMMEND THE PROPOSED APPROACH.

A. The proposed accreditation methodology will be applied to all Capacity Resources, except External Resources, in the same manner which gives it the flexibility needed to handle any resource portfolio composition. Therefore, as MISO's fleet evolves, the proposed accreditation methodology will inherently adapt to such changes. Moreover, MISO will continue to evaluate the efficacy of the DLOL-based methodology and continue discussions with stakeholders about potential enhancements going forward.

Application of the proposed accreditation methodology to all Capacity Resources, except External Resources, contrasts with the current accreditation methodologies, which are not robust enough to account for significant changes to the generation fleet. Lastly, as electrification and technological progress alters the shape of the load profile, the methodology will remain robust and provide a proper measure of the high-risk hours. Therefore, the proposed methodology satisfies the flexibility criterion as it is sufficiently robust to change in both load and generation.

Q. WHEN WEIGHING THE STABILITY CRITERION, EXPLAIN HOW MISO DECIDED TO RECOMMEND THE PROPOSED APPROACH.

A. It is important to have stability in the results. Accrediting a resource using only historical performance may subject it to significant shifts in its final accredited value, and worse off, may be lagging in representing the operational risk being experienced. By using a probabilistic model to measure the expected performance of a resource during critical hours, the method provides stability and certainty that resource accreditation will not suddenly decrease. Conversely, a method that focuses only on future expected performance could also subject a resource to dramatic shifts in capacity values if there is a significant shift in system risk. Therefore, a method that uses both historical performance and expected future performance attenuates any large shifts providing stability of accredited values. Finally, because the model is portfolio agnostic, the addition or subtraction of a set of resources will not have significant effects on existing resources, ensuring stability of capacity values for existing resources even as other Market Participants make investment decisions.

Q. WHEN WEIGHING THE COMPARABILITY CRITERION, EXPLAIN HOW MISO DECIDED TO RECOMMEND THE PROPOSED APPROACH.

A. The proposed methodology satisfies the comparability criterion by calculating accredited values for each type of Capacity Resource, except External Resources, in an identical manner. This means that a MW of accredited capacity from one type of resource can be substituted for a MW of accredited capacity from another resource without fear of the capacity values changing. Therefore, resource owners and Market Participants can directly make a cost-benefit calculation without requiring any additional calculations. This reduces

the uncertainty of investments leading to a more efficient resource portfolio. This also ensures a technology agnostic capacity valuation ensuring a non-discriminatory result.

Q. PLEASE DISCUSS THE KEY DIFFERENCES BETWEEN MARGINAL ELCC AND AVERAGE ELCC.

A. Average accreditation approaches (including average ELCC) accredit the entire class of a resource based on the contribution of the entire fleet of that class of resources, while marginal accreditation approaches measure the contribution of the next incremental addition to the resource class. By utilizing a marginal addition to the system, the marginal ELCC approach better captures how that incremental resource contributes to the needs of the system at criteria. This concept aligns with the assumption that capacity exchange in the capacity market is fungible and aligns best with something the average ELCC method is not able to provide.

VII. IMPACTS OF THE PROPOSED METHODOLOGY TO OTHER ASPECTS OF THE PRA

Q. BRIEFLY DESCRIBE HOW THE PRMR IS CURRENTLY DETERMINED.

A. The PRMR for each Season is determined as the sum of UCAP values for all resources, plus the MW adjustment to drive the probabilistic model to criteria in that Season. The current determination of UCAP values relies on a combination of accreditation methods, including EFORd based UCAP for thermal resources, seasonal capabilities for LMRs, contracted MW for firm External Resources, and average ELCC for wind and solar resources as shown in Figure 11 below.



Resource Type	Current method to establish capacity for PRMR*
Thermal	GVTC * (1 – Seasonal EFORd)
Wind/Solar	Effective Load Carrying Capability (ELCC)
Run-of-River/Biomass	Hourly output during peak hours
Storage	GVTC * 95% or hourly output during peak hours
Demand Response	Seasonal capability and # of calls
BTMG	GVTC* (1 – Seasonal EFORd)
External Resources	Firm external seasonal capability

*July for Summer, September for Fall, January for Winter and May for Spring

Figure 11: Overview of current methods for PRMR calculation

Q. PLEASE DESCRIBE HOW MISO IS PROPOSING TO CHANGE THE DETERMINATION OF PLANNING RESERVE REQUIREMENTS.

A. MISO is proposing to maintain the calculations of the PRMR and simply account for the determination of UCAP for Schedule 53A Resources, based on the proposed accreditation method. The PRMR will be determined as the sum of accredited values for all Schedule 53A Resources, Load Modifying Resources, Firm External Resources, within the LOLE model plus the MW adjustment to drive the probabilistic model to the LOLE target. As shown in Figure 12 below, MISO expects the seasonal PRMR to decrease under the proposed DLOL-based methodology compared to current season PRMR due to the

expected reduction in Resource Class-level accreditation. This result is further discussed in the Affidavit of Dr. Patton.[20]

MISO's current accreditation methodologies are misaligned with a resource's marginal contribution to reliability risk leading to over-accrediting and similarly results in higher PRMR that increases total cost to maintain Resource Adequacy at the target. The proposed accreditation method will improve alignment between accreditation and PRMR, lower PRMR and result in more efficient market outcomes.



PY 23/24 - PRMR	Summer		Fall		Winter		Spring		Formula Key
Resource Class	Current	Proposed	Current	Proposed	Current	Proposed	Current	Proposed	
Gas	30,251	29,541	28,595	29,745	28,582	23,605	28,962	23,657	[A]
Combined Cycle	27,558	27,326	28,635	27,015	28,552	23,650	27,929	22,997	[B]
Coal	40,545	39,955	39,888	38,812	39,914	32,539	39,280	32,641	[C]
Hydro (includes diversity contracts)	2,120	2,122	2,104	2,118	926	916	1,350	1,287	[D]
Nuclear	11,410	10,850	11,522	10,304	11,627	10,493	11,063	9,640	[E]
Pumped Storage	2,530	2,523	2,345	2,504	2,299	1,216	2,359	1,763	[F]
Storage	28	28	28	28	54	52	55	55	[G]
Solar	2,151	1,700	1,603	1,937	698	188	1,824	2,221	[H]
Wind	4,639	2,731	5,993	3,859	11,389	4,477	6,500	4,601	[I]
Run-of-River	966	966	966	966	966	966	966	966	[J]
BTMG	4,196	4,196	4,218	4,218	4,163	4,163	4,240	4,240	[K]
Demand Response	7,397	7,397	7,041	7,041	5,388	5,388	6,280	6,280	[L]
Firm External Support	1,707	1,707	1,714	1,714	1,857	1,857	1,778	1,778	[M]
Adj. {1d in 10yr}	(4,000)	(4,000)	(10,000)	(10,000)	(6,200)	(6,200)	(12,750)	(12,750)	[N]
PRMR	**131,498**	**127,042**	**124,652**	**120,261**	**130,215**	**103,310**	**119,836**	**99,376**	[O]= sum of [A] through [N]

Figure 12: Comparison of Current PRMR vs Proposed PRMR

Q. PLEASE DESCRIBE HOW MISO CURRENTLY CALCULATES LRR.

A. The calculation of LRR is similar to that of the PRMR, wherein the capacity is accounted for in the same way, but each LRZ is modeled independently without support from other

[20] IMM Affidavit at P 26.

LRZs or external areas, and each LRZ has its own MW adjustment to reach the seasonal LOLE criteria. Each LRZ's LRR MW is divided by the corresponding modeled zonal coincident peak forecast (LRZ load at the time of MISO's Coincident Peak Demand) to determine the LRR % that is applied to the updated LSE load forecasts for the PRA. This establishes each LRZ's LRR MW for the PRA.

Q. PLEASE DISCUSS HOW MISO PLANS TO CALCULATE LRR USING THE PROPOSED METHODOLOGY.

A. Like PRMR, LRR calculations are being updated to use accreditation by Resource Class as determined by the DLOL-based methodology. The overall approach will remain unchanged. The LRR for each LRZ is determined by aggregating the capacity accreditation of the resources in the Zone, plus a MW adjustment used to bring the LOLE model of the isolated LRZ to criteria.

As is the case with the PRMR, the main difference introduced in this proposal is the capacity accreditation for the internal resources in each LRZ (excluding LMRs). Ideally, the LRR would be determined by aggregating the final SAC values of all resources in an LRZ. However, those two values are determined at different points in time. LRR values need to be finalized in November prior to the Planning Year and final SAC values are not determined until the following February 15.

Given these scheduling challenges, MISO will produce LRR with an approximation of the final resource SAC values by combining data of the current and previous Planning Years, as follows:

1. The total Resource Class-level UCAP are determined for the current Planning Year (same values used to determine the current Planning Year PRMR).

2. Resource Class-level UCAP will be allocated to individual resources in the Resource Class using the Proposed Schedule 53A logic described earlier but utilizing the ratio of individual resource's ISAC to the corresponding Resource Class ISAC from the previous Planning Year. This provides estimated SAC values for individual resources that will only be utilized for LRR calculations.

3. The estimated SAC values are aggregated to the LRZ level, and that value is used as an input into the LRR calculations, similar to how the current method utilizes UCAP, average ELLC, or established capacity for thermal, wind, and solar resources, respectively.

Because the Schedule 53A process proposes to use the previous three years to determine Tier 1 and Tier RA 2 hours, the current and previous Planning Years, should have an overlap equal to two thirds of the hours. These should ensure a reasonable alignment between preliminary estimated and final SAC values at both the resource and LRZ levels. MISO presented an illustrative example of a system with two LRZs and four resources at the February 28, 2024 RASC meeting to explain proposed methodology for LRRs.[21]

Q. PLEASE DESCRIBE HOW MISO ALLOCATES PRMR TO INDIVIDUAL LOAD SERVING ENTITIES TODAY.

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[21] See Slides 11-12 of the MISO accreditation presentation from Feb 28th RASC meeting.

A. Through the probabilistic analysis, MISO establishes PRMR for each Season for an LSE's Load within any given LRZ. The seasonal PRMR values are converted to a Planning Reserve Margin (PRM) percentage by subtracting the modeled seasonal Coincident Peak Demand from the PRMR and dividing by the modeled seasonal Coincident Peak Demand. The PRMR used in the PRA is set by applying the seasonal PRM percentage determined from the previous step plus a transmission loss percentage to the LSE-submitted updated Coincident Peak Forecasts. MISO uses PRM % as established through the process described above and in Figure 13 unless an alternate PRM is established by a state regulatory authority. In such an event, MISO will use the alternate PRM set by the state regulatory authority for the geographic area in its jurisdiction. MISO converts any state regulatory authority provided PRM to a comparable UCAP basis.

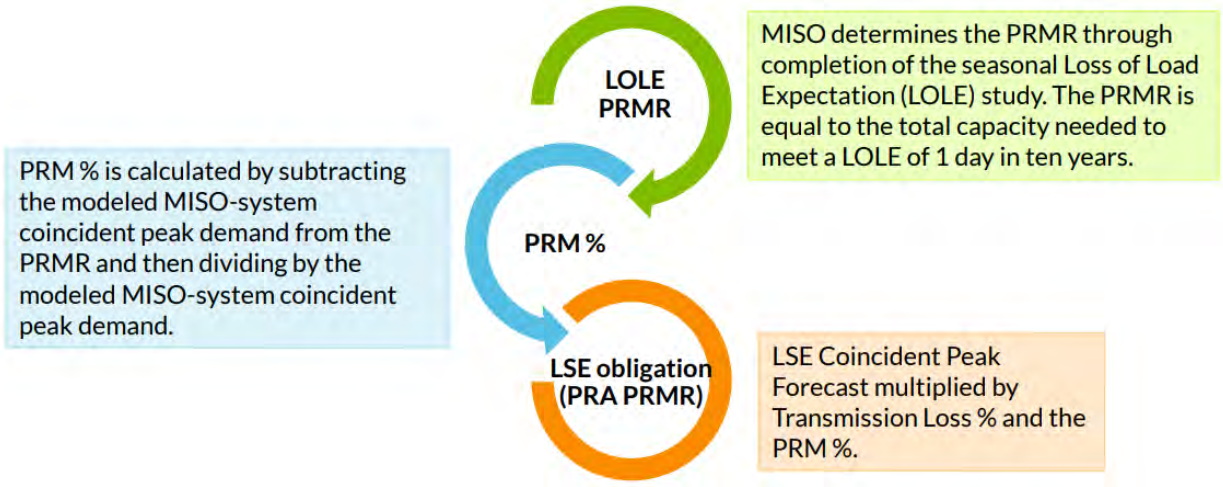


Figure 13: PRM % for Planning Resource Auction

Q. DOES MISO ADDRESS THE ALLOCATION OF PRMR TO LOAD SERVING ENTITIES WITHIN THIS FILING?

A. No. MISO is not proposing any change to the process of allocating PRMR to Load Serving Entities (LSEs) within this filing. MISO initiated stakeholder discussion on allocation of

PRMR in 2023 and concluded that any changes to the allocation process will require deliberate and careful considerations regarding substantive changes that may be needed to the processes and potentially to the systems used by LSEs to submit load forecast data to MISO. The current allocation methodology has been deemed by FERC to be just and reasonable and MISO is not proposing any changes to it. And as noted above, the proposed DLOL-based methodology will improve alignment between resource accreditation and establishment of the PRMR.

Q. DOES MISO PLAN TO ADDRESS THE ALLOCATION OF PRMR IN THE FUTURE?

A. Yes. MISO has already started conversations with stakeholders to transition from today's allocation mechanism that purely relies on the contribution to MISO's seasonal Coincident Peak Demand. MISO will consider alternative mechanisms that also incorporate recognition that risk periods in the future may not solely be determined by times of high load, as drivers of risk evolve over the next decades. MISO will evaluate these allocation mechanisms against a comprehensive set of criteria, which will be used, along with stakeholder discussions and input, to develop a final design for any future changes to how the PRMR is allocated.

Q. HOW DOES MISO'S RESOURCE CLASS-LEVEL UCAP (DLOL-BASED METHODOLOGY) ALLOW ALIGNMENT BETWEEN ACCREDITATION AND RESOURCE ADEQUACY REQUIREMENTS?

A. Under the proposed methodology, the Resource Class-Level UCAP becomes an input to the determination of PRMR and LRR. Accreditation and Resource Adequacy Requirements under the proposed accreditation methodology are determined based on the

same probabilistic model simulation and hours, increasing consistency in the process and alignment between system risks, needs, and accreditation. This improves the current situation where accreditation is separated across three different, distinct processes for thermal, wind, and solar resources, which is currently disconnected between how capacity is accounted for in the requirement calculations.

Q. HOW WILL THIS SEND THE RIGHT SIGNALS TO INVEST IN THE RIGHT MIX OF RESOURCES NEEDED TO MAINTAIN RELIABILITY IN THE MISO FOOTPRINT?

A. The proposed accreditation methodology aligns the times of system risk and need with the contribution of each Resource Class during those same periods. By consistently applying this approach to all Resource Classes, Market Participants will be able to compare how each Resource Class's ability to contribute to resource adequacy changes over time and continue to find the right balance to ensure system reliability. These signals will be complemented with forward-looking estimates for Resource Class accreditation values, which are described in Section IX.

Q. WHAT IMPACT DOES MISO'S RELIABILITY BASED DEMAND CURVE (RBDC) PROPOSAL HAVE ON THE INSTANT FILING?

A. There is no change to the RBDC proposal because of the proposed accreditation reforms. The seasonal Planning Reserve Margin Requirements, that act as the starting point of the Marginal Reliability Impact (MRI) Curve calculations, will be based on the Resource Class-level UCAP as determined through the proposed DLOL-based methodology as described above.

VIII. STAKEHOLDER ENGAGEMENT

Q. HAS MISO SOLICITED AND CONSIDERED STAKEHOLDER INPUT IN DEVELOPING THE PROPOSED ACCREDITATION METHODOLOGY?

A. Yes, MISO's proposed accreditation methodology is based on robust stakeholder discussions over the last two years (Figure 14). The stakeholder discussions on accreditation reforms began in January 2022 following Tariff filings for reforms to thermal resource accreditation and seasonal Resource Adequacy construct. As described in Section VI above, MISO used its product development process to frame the issue or problem statement and evaluate options throughout 2022. In November 2022, MISO recommended the proposed two-step accreditation methodology for wind and solar resources. At the January 2023 RASC, MISO recommended extending the scope of the accreditation reform effort to cover accreditation changes for all Capacity Resources, except External Resources. One of the main reasons for this extension of scope was the stakeholder feedback to have a uniform accreditation methodology for all resources. Subsequently, throughout 2023 and in early 2024, MISO engaged stakeholders at the RASC and solicited their input to develop a detailed design for the proposed methodology.



Figure 14: Accreditation Reform Stakeholder Engagement Timeline

Q. DID MISO CHANGE ITS PROPOSED DESIGN TO ADDRESS STAKEHOLDER FEEDBACK?

A. MISO has made several improvements to its accreditation proposal based on feedback provided as a part of the stakeholder process. Stakeholder discussion and feedback played a substantial role in shaping the design of the accreditation reform proposed herein.

As discussed earlier, the initial scope of the instant accreditation reform included non-thermal resources including solar and wind resources. Stakeholders provided feedback and MISO agreed that accreditation across all fuel types should be comparable. In response to this feedback and to bring resources under the same accreditation methodology, MISO extended the scope of the accreditation reform to apply to all applicable Capacity Resources. This change, in response to stakeholder feedback, provides improved and consistent accreditation across resources of different fuel types.

Stakeholders also had concerns that basing accreditation on only modeled loss of load hours may not adequately account for reliability risks. Feedback from stakeholders suggested that MISO expand the hours considered in the DLOL-based methodology to include additional hours with increased reliability risk. After evaluation, MISO agreed with stakeholders that relying on only loss of load hours could result in scenarios where reliability risks during hours, when available generation is just sufficient to meet the demand (e.g., total available generation is 50 MW above load in a given hour), is not captured in the calculation. Additionally, relying on only loss of load hours could also result in year-over-year volatility especially when the number of loss of load hours in a particular Season is smaller. Upon consideration, MISO expanded its definition of Critical

Hours to include additional low margin hours in addition to loss of load hours. The expanded Critical Hours provides stability improvements to the resulting accreditation.

Along with expanding hours, MISO also considered Stakeholder feedback that modeled results should be weighted by expected unserved energy (EUE) in the probabilistic model that would weight results by the severity of modeled risk. Although the MISO design team was in favor of weighting hours by severity of risk, using only EUE to weight results would provide weight for only loss of load hours, giving any low margin hours no weight at all. To provide both weighting and consideration of expanded hours, the weighting methodology proposed above provides the most weight to the hours with the greatest reliability risk and provides comparable weights to hours with similar risk around the loss of load threshold.

Although occurring late in the design process, Stakeholder feedback helped shape the Local Resource Requirement design provided above. The revised LRR design proposal is a result of substantial opposition to the originally proposed design. In response to this overwhelming opposition, the MISO design team crafted a new LRR proposal. The resulting positive stakeholder feedback suggests that the revised approach described above is the right balance within the proposed accreditation reform.

Throughout the Stakeholder process, the feedback was clear that there was a need for better understanding of the probabilistic model. To help stakeholders better understand MISO business practices around LOLE modeling and probabilistic analysis, MISO hosted a LOLE modeling and Accreditation Reform workshop for stakeholders in September

2023.[22] As a part of stakeholder process for the proposed accreditation reforms, MISO and stakeholders discussed and agreed that LOLE modeling improvements are important to align the probabilistic model with the expected operation of resources. As discussed further below, improving and enhancing the probabilistic model is an iterative and ongoing process. In response to extensive stakeholder feedback, MISO has recently kicked off a formal stakeholder process for LOLE modeling enhancements.

Stakeholders also voiced concerns about the timing for implementation of the proposed accreditation methodology. Among other concerns, stakeholders noted that resource planning and investment decisions are already being implemented and that sufficient time is needed before applying the new accreditation methodology in the Planning Resource Auction. In response to this stakeholder feedback, MISO is proposing the three-year transition period described below. In addition, MISO is committed to providing stakeholders with indicative information about the impact of the proposed changes both during the transition period and going forward.

Q. WHAT ARE MISO'S PLANS AND COMMITMENTS TO IMPROVING THE PROBABILISTIC MODEL?

A. As described above, the Resource Class accreditation values established through the proposed methodology are a direct outcome from the probabilistic model. It is important to note that MISO regularly evaluates its LOLE process to determine whether enhancements can be implemented to reflect changing system conditions more accurately. Recent improvements that have been made to the probabilistic model include the addition

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[22] *See* MISO's LOLE Modeling & Accreditation Reform Workshop - September 22, 2023 (misoenergy.org)

of a cold-weather outage adder, use-limited modeling of Electric Storage Resources, renewable profiles, inclusion of a probabilistic distribution of non-firm external support, and the addition of seasonal forced outage rates. This is an ongoing process that is necessary to help ensure the LOLE results are consistent with the underlying risk parameters. MISO is committed to continuing this process of enhancing the probabilistic model to better reflect risks across the year. Any future changes to the probabilistic model to better reflect risk will then be reflected in both the Resource Adequacy Requirements and accreditation values. Improving the probabilistic model is the best way to capture risk more accurately, which will better reflect the contribution to reliability of the resources modeled. As mentioned previously in Section V, MISO has communicated a plan to stakeholders to research, design, and implement specific aspects of the probabilistic model, including a revision of planned outages, cold-weather outages, load forecasting, and storage modeling. For example, through several discussions with stakeholders, MISO recognizes that SERVM may not currently distribute planned outages consistently across Resource Classes which may have inadvertent impacts on Resource Class-level UCAP. MISO has already initiated discussions at the RASC to further investigate this potential issue and address it as needed prior to implementation. The planned model improvements will further refine alignment between risk, needs, and availability, as will further improvements performed in the future.

Q. IS MISO COMMITTED TO IMPROVING STORAGE DISPATCH MODELING?

A. Starting with Planning Year 2024-2025, MISO started representing Electric Storage Resources with SERVM's native model for energy-limited resources. MISO is planning to simulate future-looking cases, with increased penetration of storage to better understand

how the advent of these resources affect the probabilistic model results and the distribution of risk in the MISO footprint in the future.

Q. WHAT IS MISO DOING TO PROVIDE MORE TRANSPARENCY REGARDING THE DATA AND INPUTS TO THE PROBABILISTIC MODEL?

A. MISO currently makes available to stakeholders many of the inputs to the probabilistic model, e.g., shapes for 30 years of load, wind, and solar, as well as documents the development process for other inputs.[23] Throughout the stakeholder engagement period, MISO has produced Resource Class estimates for the proposed accreditation methodology under a variety of assumptions and configurations, as well as the resulting impacts on PRMR and LRR values. MISO has also shared with individual Market Participants their specific resource-level estimates.

Additionally, MISO has engaged with stakeholders on several occasions to explain the current limitations, including specific data items, that prevent MISO from sharing the probabilistic model and has requested feedback to overcome said limitations. MISO's Tariff, however, prohibits MISO from sharing resource-specific information, which is the property of the various Market Participants, including outage rates and granular load forecasts without express approval from all Market Participants. MISO has initiated conversations at the January and February 2024 RASC meetings to improve upon data transparency.[24] MISO is committed to establishing a new process to provide additional data

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[23] *See* Astrapé Consulting: *MISO Seasonal Inputs for the 2022 LOLE Study* available at: https://cdn.misoenergy.org/20220707%20LOLEWG%20Supplemental%20MISO%20Seasonal%20Inputs%20Documentation%20Astrape625466.pdf

[24] See LOLE Model Data Transparency, February 28, 2024 RASC available at: https://cdn.misoenergy.org/20240228%20RASC%20Item%2005b%20LOLE%20Data%20Transparency631895.pdf

annually to stakeholders related to the probabilistic model's generation inputs while continuing to share shapes for 30 years of load, wind and solar. The additional data will be masked, rolled up, or provided with class averages so that stakeholders can replicate results while maintaining data confidentiality, consistent with the requirements of its Tariff and recent stakeholder feedback.

IX. TRANSITION PERIOD AND IMPLEMENTATION TIMELINE

Q. WHAT EFFECTIVE DATE HAS MISO REQUESTED FOR THE RESOURCE ACCREDITATION REFORM PROPOSAL?

A. MISO has requested an effective date of September 1, 2024, for the reporting requirement included in the Tariff. Pursuant to the proposed Tariff Schedule 53A, beginning September 1, 2024, MISO will be required to publish Resource Class-level indicative results and provide resource-level indicative results by Market Participant to individual resource owners as requested prior to the PRA beginning with the 2025 PRA for Planning Year 2025 – 2026 and continuing for the next two Planning Years.

Q. WHEN DOES MISO PLAN TO IMPLEMENT THE PROPOSED ACCREDITATION METHODOLOGY?

A. MISO plans to use the proposed accreditation methodology to accredit resources beginning with the 2028 PRA for Planning Year 2028 – 2029 (Figure 15). During the three-year transition period, beginning with Planning Year 2025 – 2026, MISO will provide resource-level results as requested to Market Participants using the proposed methodology so that they understand the impact on their resources prior to implementation.

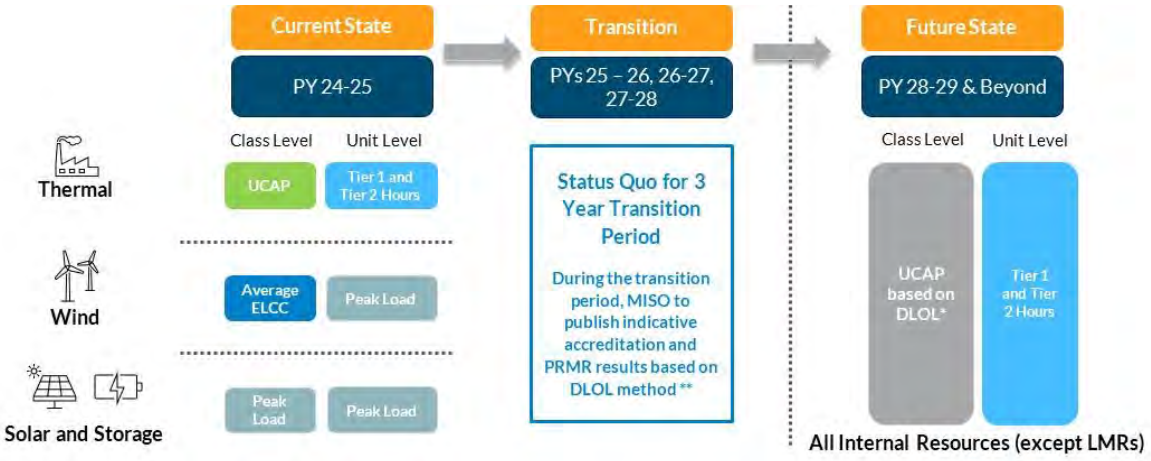


Figure 15: Effective Date and Transition Plan shared with stakeholders

Q. WHY HAS MISO CHOSEN A SEPTEMBER 1, 2024 EFFECTIVE DATE GIVEN IT DOES NOT INTEND TO IMPLEMENT THE PROPOSED METHODOLOGY UNTIL PLANNING YEAR 2028 – 2029?

A. The three-year transition period is an important aspect of the overall proposal and, as discussed above, was developed to address stakeholder concerns regarding implementation timing. MISO recognizes that the change in the accreditation methodology is a significant one and has designed the transition period to provide Market Participants an opportunity to adjust to the change. This transition period will assist LSEs with integrated resource planning by equipping them with the data they need to make long-term investment decisions.

Q. HOW WILL MISO PROVIDE INDICATIVE RESULTS TO STAKEHOLDERS DURING THE TRANSITION PERIOD?

A. For each of the Planning Years during the transition period, MISO will provide indicative results for the proposed accreditation methodology. The Resource Class-level UCAP, PRMR, and LRR estimates will be made available to stakeholders and will be based on the same probabilistic model simulation results used to determine the PRMR in that Planning

Year. Market Participants will also be provided with the indicative Schedule 53A SAC values for their own resources as requested. Indicative results will be generated concurrent with existing processes and MISO will produce them as soon as feasible.

Q. HOW WILL MISO PROVIDE FORWARD-LOOKING RESOURCE ACREDITATION ESTIMATES?

A. To assist LSEs with integrated resource planning needed to make long-term investment and retirement decisions, MISO will provide future year (5 and 10 year forward) estimated Resource Class-level accreditation values annually as part of MISO's Renewable Resource Assessment (RRA) study starting in 2024. Additional data needs and sensitivities will be considered as these estimates are developed. Just as with all future predictions, the degree of uncertainty in the inputs alone (future demand growth, change in consumer behavior, future generation technologies, rate of retirements and deployment, etc.) can substantially vary the outcome of RA needs and LOLE analysis for such long timeframes.

Q. HOW WILL RESOURCES BE ACCREDITED DURING THE TRANSITION PERIOD?

A. The transition proposal includes keeping the status quo accreditation methodologies for all resource types until PY 2028-2029. Following the transition period, MISO intends to apply the proposed accreditation methodology to all Capacity Resources including thermal, wind, solar and Electric Storage Resources.

X. CONCLUSION

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

Affidavit of Zakaria Joundi

COUNTY OF HAMILTON)
)
STATE OF INDIANA)

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

Zakaria Joundi

SUBSCRIBED AND SWORN BEFORE ME, this 27 day of March, 2024.

(Notary Public Signature)

Commissioned in Clinton county.

Commission Number: 705772

Commission Expires: 9/27/2025

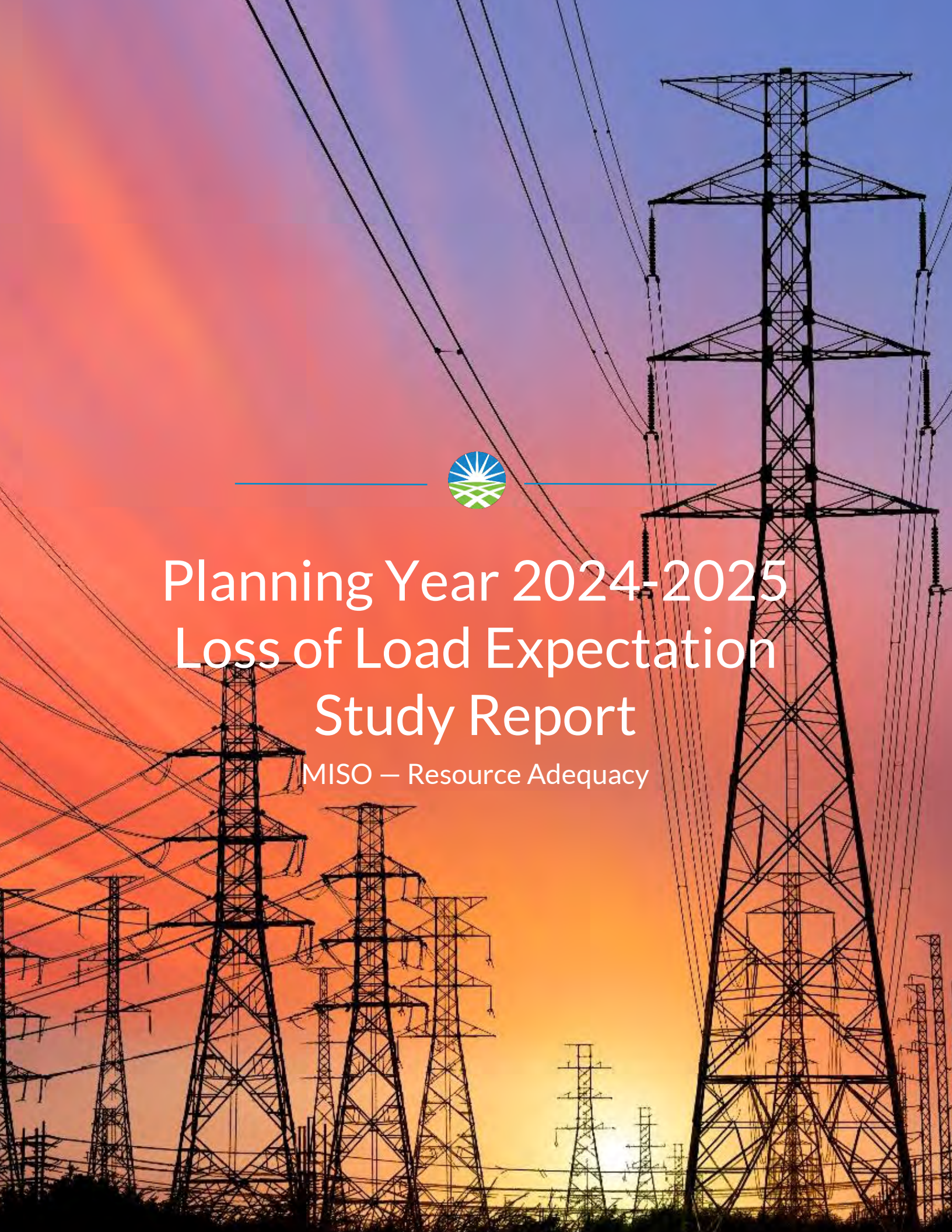
RHIANNON RENA SHELLEY
Clinton County
My Commission Expires
September 27, 2025

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

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

Exhibit 82
MISO 2024-25 LOLE Study Report



Planning Year 2024-2025 Loss of Load Expectation Study Report

MISO — Resource Adequacy

Contents

Contents 2
Executive Summary 4
1 LOLE Study Process Overview 7
1.1 Study Improvements 8
2 Transfer Analysis 9
2.1 Calculation Methodology and Process Description 9
2.1.1 Generation Pools 9
2.1.2 Redispatch 9
2.1.3 Sensitivity 10
2.1.4 Generation Limited Transfer for CIL/CEL and ZIA/ZEA 11
2.1.5 Voltage Limited Transfer for CIL/CEL and ZIA/ZEA 11
2.2 Powerflow Models and Assumptions 12
2.2.1 Tools Used 12
2.2.2 Inputs Required 12
2.2.3 Powerflow Modeling 12
2.2.4 General Assumptions 13
2.3 Results for CIL/CEL and ZIA/ZEA 14
3 Loss of Load Expectation Analysis 25
3.1 LOLE Modeling Input Data and Assumptions 25
3.2 MISO Generation 25
3.2.1 Thermal Units 25
3.2.2 Behind-the-Meter Generation 28
3.2.3 Attachment Y 28
3.2.4 Future Generation 28
3.2.5 Intermittent Resources 28
3.2.6 Demand Response 29
3.3 MISO Load Data 29
3.3.1 Weather Uncertainty 29
3.3.2 Economic Load Uncertainty 30
3.4 External System 31
3.5 Loss of Load Expectation Analysis and Metric Calculations 32

3.5.1 Seasonal LOLE Distribution 32
3.5.2 MISO-Wide LOLE Analysis and PRM Calculation 33
3.5.3 LRZ LOLE Analysis and Local Reliability Requirement Calculation 34
4 MISO System Planning Reserve Margin 35
4.1 Planning Year 2024-2025 MISO Planning Reserve Margin Results 35
4.1.1 Additional Risk Metric Statistics 35
4.2 Comparison of PRM Targets Across 10 Years 36
5 Local Resource Zone Analysis – LRR Results 37
5.1 Planning Year 2024-2025 Local Resource Zone Analysis 37
6 Appendix A: Comparison of Planning Year 2023-2024 to Planning Year 2024-2025 42
6.1 Waterfall Chart Details 45
6.1.1 Updated Weather Year Profiles 45
6.1.2 Updated Non-Firm Support 45
6.1.3 Updated Resource Mix / Performance 45
6.1.4 Updated Cold Weather Outage Adder (Winter only) 45
6.1.5 Accounting Improvement for Cold Weather Outage Adder (Winter only) 45
7 Appendix B: Increased Winter Thermal Capability Sensitivity 46
8 Appendix C: Capacity Import Limit Tier 1 & 2 Source Subsystem Definitions 47
9 Appendix D: Compliance Conformance Table 51
10 Appendix E: Acronyms List Table 56
11 Appendix F: Outyear PRM Results 58
11.1 Planning Year 2027-2028 MISO Planning Reserve Margin Results 58
11.2 Planning Year 2029-2030 MISO Planning Reserve Margin Results 59
11.3 MISO Planning Reserve Margin Outyear Projections 60

April 2024 Update: Outyear Planning Reserve Margin (PRM) and additional EFORd results added to report.

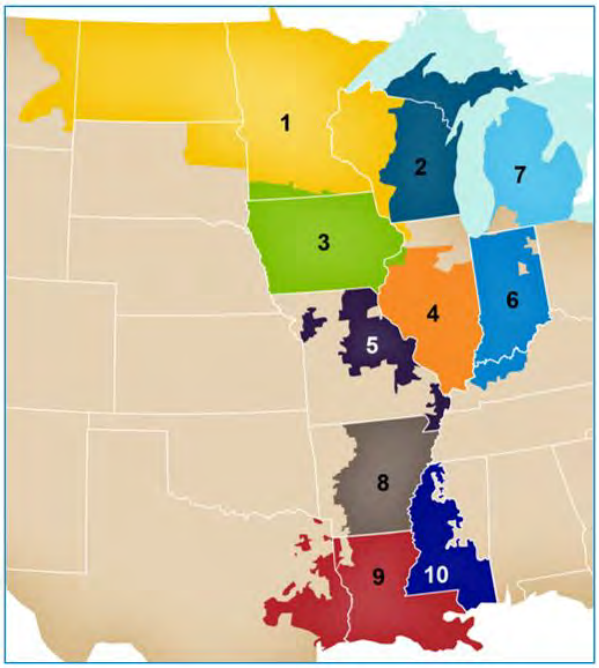
Executive Summary

In preparation for the annual Planning Resource Auction, MISO conducts an annual Loss of Load Expectation (LOLE) study to determine Resource Adequacy Requirements for the upcoming Planning Year 2024-2025. These requirements are identified on a seasonal basis for each Local Resource Zone within MISO.

Planning Reserve Margin (PRM) determined through this year's study are:

Season	PRM UCAP %
Summer 2024	9.0%
Fall 2024	14.2%
Winter 2024-2025	27.4%
Spring 2025	26.7%

MISO is divided into ten Local Resource Zones (LRZs) as shown in the figure below.



Local Resource Zone	Local Balancing Authorities
1	DPC, GRE, MDU, MP, NSP OTP, SMP
2	ALTE, MGE, MIUP, UPPC, WEC, WPS
3	ALTW, MEC, MPW
4	AMIL, CWLP, GLH, SIPC
5	AMMO, CWLD
6	BREC, CIN, HE, HMPL, IPL, NIPS, SIGE
7	CONS, DECO
8	EAI
9	CLEC, EES, LAFA, LAGN, LEPA
10	EMBA, SME

The report also determines zonal Local Reliability Requirements (LRRs). Additionally, initial values for zonal Capacity Import Limits (CIL), Capacity Export Limits (CEL), Zonal Import Ability (ZIA), and Zonal Export Ability (ZEA) for each season are also determined. These quantities are described in section 2.3.

Tables ES-1 through ES-4 below show results for each season.

PRA and LOLE Metrics	LRZ 1	LRZ 2	LRZ 3	LRZ 4	LRZ 5	LRZ 6	LRZ 7	LRZ 8	LRZ 9	LRZ 10
Summer 2024 PRM UCAP	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%	9.0%
LRR UCAP per-unit of LRZ Peak Demand	1.132	1.113	1.278	1.291	1.331	1.190	1.161	1.392	1.135	1.518
Capacity Import Limit (CIL) (MW)	6,462	4,506	5,009	10,790	3,208	7,463	4,500	3,536	5,613	3,564
Capacity Export Limit (CEL) (MW)	4,537	3,971	5,450	2,730	4,644	5,637	5,709	6,171	2,359	1,840
Zonal Import Ability (ZIA) (MW)	6,460	4,506	4,911	9,857	3,208	7,197	4,490	3,444	4,794	3,564
Zonal Export Ability (ZEA) (MW)	4,539	3,971	5,548	3,663	4,644	5,903	5,719	6,263	3,178	1,840

Table ES-1: Initial Planning Resource Auction Deliverables — Summer 2024

PRA and LOLE Metrics	LRZ 1	LRZ 2	LRZ 3	LRZ 4	LRZ 5	LRZ 6	LRZ 7	LRZ 8	LRZ 9	LRZ 10
Fall 2023 PRM UCAP	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%	14.2%
LRR UCAP per-unit of LRZ Peak Demand	1.235	1.199	1.345	1.323	1.441	1.257	1.311	1.496	1.190	1.667
Capacity Import Limit (CIL) (MW)	6,502	5,719	6,789	6,637	3,786	8,954	4,400	5,040	6,435	4,736
Capacity Export Limit (CEL) (MW)	5,711	4,512	6,913	3,863	5,402	3,519	5,381	4,212	3,602	2,889
Zonal Import Ability (ZIA) (MW)	6,500	5,719	6,684	5,699	3,786	8,661	4,390	4,942	5,608	4,736
Zonal Export Ability (ZEA) (MW)	5,713	4,512	7,018	4,801	5,402	3,812	5,391	4,310	4,429	2,889

Table ES-2: Initial Planning Resource Auction Deliverables — Fall 2024

PRA and LOLE Metrics	LRZ 1	LRZ 2	LRZ 3	LRZ 4	LRZ 5	LRZ 6	LRZ 7	LRZ 8	LRZ 9	LRZ 10
Winter 24-25 PRM UCAP	27.4%	27.4%	27.4%	27.4%	27.4%	27.4%	27.4%	27.4%	27.4%	27.4%
LRR UCAP per-unit of LRZ Peak Demand	1.442	1.363	2.006	1.338	1.285	1.227	1.607	1.560	1.328	1.864
Capacity Import Limit (CIL) (MW)	4,693	5,523	5,704	6,731	4,477	8,526	4,666	4,336	5,420	3,219
Capacity Export Limit (CEL) (MW)	5,174	4,772	8,975	4,650	6,229	1,407	5,743	5,808	2,103	2,993
Zonal Import Ability (ZIA) (MW)	4,691	5,523	5,600	5,811	4,477	8,286	4,656	4,262	4,623	3,219
Zonal Export Ability (ZEA) (MW)	5,176	4,772	9,079	5,570	6,229	1,647	5,753	5,882	2,900	2,993

Table ES-3: Initial Planning Resource Auction Deliverables — Winter 2024-2025

PRA and LOLE Metrics	LRZ 1	LRZ 2	LRZ 3	LRZ 4	LRZ 5	LRZ 6	LRZ 7	LRZ 8	LRZ 9	LRZ 10
Spring 2024 PRM UCAP	26.7%	26.7%	26.7%	26.7%	26.7%	26.7%	26.7%	26.7%	26.7%	26.7%
LRR UCAP per-unit of LRZ Peak Demand	1.329	1.363	1.531	1.662	1.618	1.371	1.322	1.610	1.334	1.878
Capacity Import Limit (CIL) (MW)	4,943	5,034	6,626	6,003	3,892	8,015	4,893	6,124	6,417	4,628
Capacity Export Limit (CEL) (MW)	6,318	4,601	5,761	5,081	4,984	3,444	5,591	4,936	3,994	2,740
Zonal Import Ability (ZIA) (MW)	4,941	5,034	6,514	5,083	3,892	7,730	4,883	6,030	5,598	4,628
Zonal Export Ability (ZEA) (MW)	6,320	4,601	5,873	6,001	4,984	3,729	5,601	5,030	4,813	2,740

Table ES-4: Initial Planning Resource Auction Deliverables — Spring 2025

The stakeholder review process played an integral role in this study. MISO would like to thank the Loss of Load Expectation Working Group (LOLEWG) and the Resource Adequacy Subcommittee (RASC) for its assistance and input.

1 LOLE Study Process Overview

In compliance with Module E-1 of the MISO Tariff, MISO performed its annual LOLE Study to determine, for each season of Planning Year 2024-2025, the system Unforced Capacity (UCAP) Planning Reserve Margin (PRM) and the per-unit Local Reliability Requirements (LRR) of Local Resource Zone (LRZ) Peak Demand.

In addition to the LOLE analysis, MISO performed seasonal transfer analyses to determine seasonal Zonal Import Ability (ZIA), Zonal Export Ability (ZEA), Capacity Import Limits (CIL) and Capacity Export Limits (CEL). CIL, CEL, and ZIA are used, in conjunction with the LOLE analysis results, in the Planning Resource Auction (PRA). ZEA is informational and not used in the PRA.

The PY 2024-2025 per-unit seasonal LRR UCAP multiplied by the updated LRZ seasonal Peak Demand forecasts submitted for the 2024-2025 PRA determines each LRZ's seasonal LRR. Once the seasonal LRR is determined, the ZIA values and non-pseudo tied exports are subtracted from the seasonal LRR to determine each LRZ's seasonal Local Clearing Requirement (LCR) consistent with Section 68A.6 of Module E-1[1]. An example LCR calculation pursuant to Section 68A.6 of the current effective Module E-1 shows how these values are reached (Table 1-1).

Local Resource Zone (LRZ) EXAMPLE	Example LRZ	Formula Key
Installed Capacity (ICAP)	17,442	[A]
Unforced Capacity (UCAP)	16,326	[B]
Adjustment to UCAP (1d in 10yr)	50	[C]
Local Reliability Requirement (LRR) (UCAP)	16,376	[D]=[B]+[C]
LRZ Peak Demand	14,270	[E]
LRR UCAP per-unit of LRZ Peak Demand	114.8%	[F]=[D]/[E]
Zonal Import Ability (ZIA)	3,469	[G]
Zonal Export Ability (ZEA)	2,317	[H]
Local Clearing Requirement (LCR) EXAMPLE	**Example LRZ**	**Formula Key**
Non-Pseudo Tied Exports (UCAP)	150	[J]
Local Reliability Requirement (LRR) (UCAP)	16,376	[K]=[F]*[E]
Local Clearing Requirement (LCR)	12,757	[L]=[K]-[G]-[J]

Table 1-1: Example Local Clearing Requirement Calculation

The actual effective PRM Requirement (PRMR) for each season of Planning Year 2024-2025 will be determined after the updated LRZ Seasonal Peak Demand forecasts are submitted by November 1, 2023, for the 2024-2025 PRA. The ZIA, ZEA, CIL and CEL values are subject to updates in March 2024 based on changes to exports of MISO resources to non-MISO load, changes to pseudo tied commitments, and updates to facility ratings following the completion of the LOLE Study.

[1] https://www.misoenergy.org/legal/tariff
Effective Date: September 1, 2022

Finally, the Simultaneous Feasibility Test (SFT) is performed as part of the PRA where the deliverability of cleared generation is validated through transfer analysis modeling to ensure transmission reliability. If constraints arise, they are mitigated by adjusting CIL and CEL values as needed.

1.1 Study Improvements

The Planning Year 2024-2025 LOLE Study incorporated additional study improvements, building on those incorporated in the prior studies. Improvements for the PY 2023-2024 LOLE Study included modeling of seasonal outage rates, correlated cold weather outage adder profiles, a probabilistic distribution of non-firm support, and 30 years of hourly wind and solar profiles. Details for these changes can be found in the PY 2023-2024 LOLE Study Report.

The PY 2024-2025 LOLE Study included the following improvements:

- **Enhanced modeling of battery storage resources:** Previously, battery storage was modeled as a must-run resource that is always available at nameplate capacity, unless on a forced outage (assumed to be a rate of 5% for every season). Now, battery storage is modeled as use-limited with a duration of 4 hours.

- **Realistic commercial operation dates for future resources**: PY 2024-2025 study considered more realistic anticipated commercial operation dates (CODs) for future resource additions with executed generation interconnection agreements (GIAs), factoring in macroeconomic and regulatory realities. Interconnection customers have indicated to MISO that factors such as supply-chain issues, regulatory approvals, contractor availability, and other economic factors such as PPAs, are requiring GIA projects to delay commercial operations. Correspondingly, declared anticipated CODs were adjusted based on GIA projects in the queue per customer feedback.

- **Improved consideration of outages driven by extreme cold temperatures**: Accounting of additional forced outages during extreme cold temperatures in the Winter season was updated in the PRM and LRR calculations. For context, the LOLE model has historically utilized a 5-year average EFORd based on historic GADS data. These resource-specific forced outage rates were annualized under the prior annual construct and were seasonalized in the PY 2023-2024 LOLE Study, which better captured the seasonal availability of resources as observed in operations.

  Additional thermal forced outages are added to the model during times of extreme cold temperatures to better capture the magnitude of observed correlated outages. The magnitude of forced outages added increases as temperatures decrease based on the relationship between outages and temperature determined from historic GADS and weather data. The modeling of additional forced outages in the Winter season due to the adder induces a higher volume of forced outages in the model beyond just the average Winter EFORd. Each LRZ has a unique outage/temperature profile based on actual historical forced outages. The incremental cold weather outages are not assigned to a particular resource but instead represent the aggregate impact on the system for coal, gas, and combined cycle resources.

  The accounting of reduced Winter Unforced Capacity resulting from additional extreme cold weather outages was improved in the most recent PRM and LRR calculations. A comparative probabilistic analysis, with and without the cold weather outage adder, was performed to quantify the impact of modeling the cold weather outage adder profiles on the system-wide requirements. This impact was distributed pro-rata to the zonal level based on the average magnitude of the zonal cold weather outage adder profiles used in the LRR calculations.

2 Transfer Analysis

2.1 Calculation Methodology and Process Description

Transfer analyses determined CIL and CEL values for LRZs in each season for Planning Year 2024-2025. Annual adjustments are made for Border External Resources and Coordinating Owner Resources to determine the ZIA and ZEA in each season. Further adjustments are made for exports to non-MISO loads to arrive at the CIL and CEL values. The objective of the transfer analyses is to determine constraints caused by the transfer of capacity between zones and the associated transfer capability. Multiple factors impacted the analysis when compared to previous studies, including:

- Approximately 800 MW of retirements and/or suspensions
- New intermittent resources
- Base model dispatch in MISO and seams

2.1.1 Generation Pools

To determine an LRZ's import or export limit, a transfer is modeled by ramping generation up in a source subsystem and ramping generation down in a sink subsystem. The source and sink definitions depend on the limit being tested. The LRZ studied for import limits is the sink subsystem and the adjacent MISO LBAs are the source subsystem. The LRZ studied for export limits is the source subsystem and the rest of MISO is the sink subsystem. These are the same in all seasons for the upcoming Planning Year.

Transfers can cause potential issues, which are addressed through the study assumptions. First, an abundantly large source pool spreads the impact of the transfer widely which can cause differences in studied zones' transfer capabilities and the identified constraints. Second, ramping up generation from remote areas could cause electrically distant constraints for any given LRZ, which should not determine a zone's limit. For example, export constraints due to dispatch of LRZ 1 generation in the northwest portion of the footprint should not limit the import capability of LRZ 10, which covers the MISO portion of Mississippi.

To address these potential issues, the transfer studies limit the source pool for the import studies to the Tier 1 and Tier 2 adjacent LBAs to the study zone. Since the generation that is ramped up in export studies are contained in the study LRZ, these issues only apply to import studies. Generation within the zone studied for an export limit is ramped up and constraints are expected to be near or in the study zone.

2.1.2 Redispatch

Limited redispatch is applied after performing transfer analyses to mitigate constraints. Redispatch ensures constraints are not caused by the base dispatch and aligns with potential actions that can be implemented for the constraint by MISO control room operators. Redispatch scenarios can be designed to address multiple constraints, as required, and may be used for constraints that are electrically close to each other or to further optimize transfer limits for several constraints requiring only minor redispatch. The redispatch assumptions include:

- The use of no more than 10 conventional fuel plants or intermittent resources
- Redispatch limit at 2,000 MW total (1,000 MW up and 1,000 MW down)
- No adjustments to nuclear units
- No adjustments to the portions of pseudo-tied units committed to non-MISO load

2.1.3 Sensitivity

New to the transfer analyses this year is the ability for Transmission Owners in a specific zone to request a sensitivity be included in the generation-to-generation transfer to allow for the True Transfer Limit to be identified. The sensitivity would allow excluded units to be included in the generation-to-generation transfer for a zone's CIL. Excluded units mainly include nuclear units and units not to be used in zonal transfers from the latest MTEP model. This sensitivity can only be requested for a CIL study. A sensitivity would only be accepted for a particular zone if they are in the situation portrayed below by the chart in Figure 2-1.

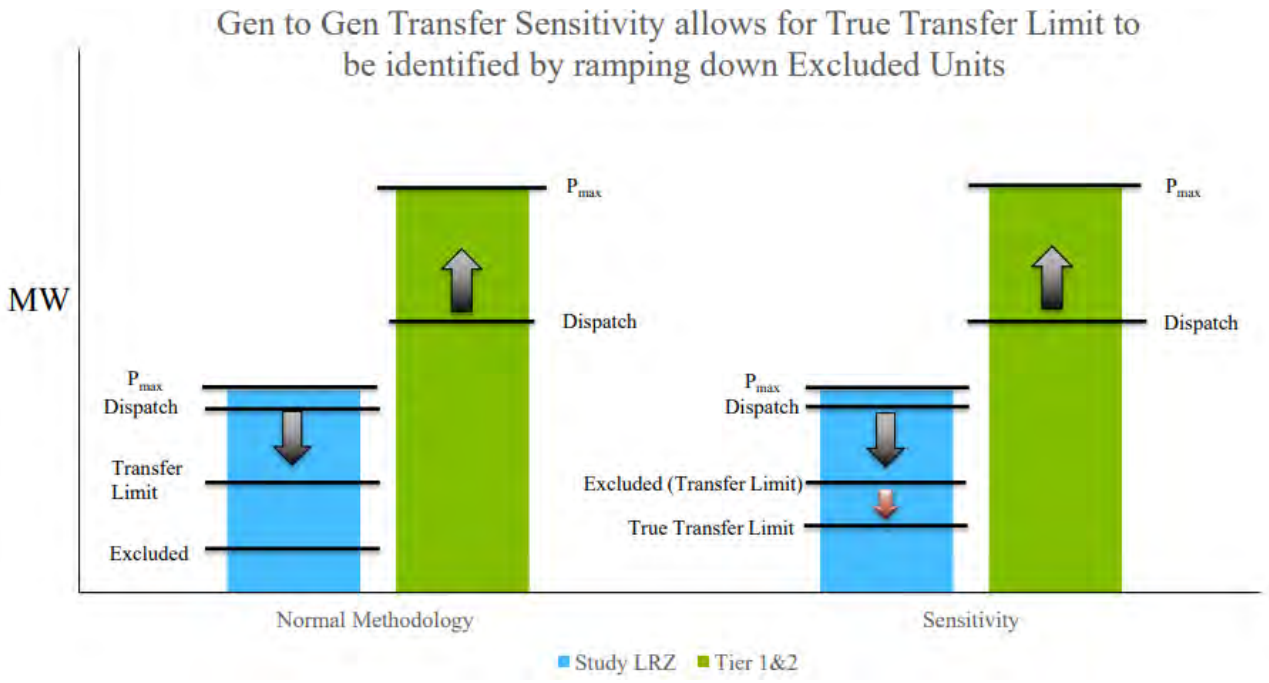


Figure 2-1: Generation-to-Generation Transfer Sensitivity

The two bars shown for the Normal Methodology would not allow for a sensitivity to be requested by a Transmission Owner. In this situation, since the transfer limit is already identified before hitting the excluded units, a request for a generation-to-generation transfer sensitivity would not be accepted. The two bars shown for the Sensitivity identify a situation where a request for a generation-to-generation transfer sensitivity would be accepted. When ramping down generation, the excluded units are hit before the True Transfer Limit, but since the rest of the units are excluded, the transfer limit would be identified as the point where the generation-to-generation stops at the excluded units. With a sensitivity in place, the generation-to-generation transfer would continue into the excluded units and the True Transfer Limit would be identified.

LRZ 10 was the only Local Resource Zone to utilize a generation-to-generation transfer sensitivity and have the results of which included in their Capacity Import Limit for Planning Year 2024-2025.

2.1.4 Generation Limited Transfer for CIL/CEL and ZIA/ZEA

When conducting transfer analysis to determine import or export limits, the source subsystem might run out of generation to dispatch before identifying a valid constraint caused by a transmission limit. MISO developed a Generation Limited Transfer (GLT) process to identify transmission constraints in these situations, when possible, for both imports and exports.

After running the First Contingency Incremental Transfer Capability (FCITC) analysis to determine limits for each LRZ, MISO will determine whether a zone is experiencing a GLT (e.g. whether the first constraint would occur only after all the generation is dispatched at its maximum amount). If the LRZ experiences a GLT, MISO will adjust the base model depending on whether it is an import or export analysis and re-run the transfer analysis.

For an export study, when a transmission constraint has not been identified after all generation has been dispatched within the exporting system (LRZ under study), MISO will decrease load and generation dispatch in the study zone. The adjustment creates additional capacity to export from the zone. After the adjustments are complete, MISO will re-run the transfer analysis. If a GLT reappears, MISO will make further adjustments to the load and generation of the study zone.

For an import study, when a transmission constraint has not been identified after all generation has been dispatched within the source subsystem, MISO will decrease load and generation in the source subsystem. This increases the export capacity of the adjacent LBAs for the study zone. After the adjustments are complete, MISO will run the transfer analysis again. If a GLT reappears, MISO will make further adjustments to the model's load and generation in the source subsystem.

FCITC could indicate the transmission system can support larger thermal transfers than would be available based on installed generation for some zones—however, large variations in load and generation for any zone may lead to unreliable limits and constraints. Therefore, MISO limits load scaling for both import and export studies to 50 percent of the zone's load. In a GLT, redispatch, or GLT plus redispatch scenario, the FCITC of the most limiting constraint might exceed Zonal Export/Import Capability. If the GLT does not produce a limit for a zone, either due to a valid constraint not being identified or due to other considerations as listed in the prior paragraph, MISO shall report that LRZ as having no limit and ensure that the limit will not bind in the first iteration of the Simultaneous Feasibility Test (SFT).

2.1.5 Voltage Limited Transfer for CIL/CEL and ZIA/ZEA

Zonal imports may be limited by voltage constraints due to a decrease in the generation in the study zone. Voltage constraints might occur at lower transfer levels than thermal limits determined by linear FCITC. As such, LOLE studies may evaluate power-voltage curves for LRZs with known voltage-based transfer limitations identified through existing MISO or Transmission Owner studies. Such evaluation may also occur if an LRZ's import reaches a level where the majority of the zone's load would be served using imports from resources outside of the zone. MISO will coordinate with stakeholders as it encounters these scenarios. For Planning Year 2024-2025, only Local Resource Zones 1, 4, and 7 import analyses included voltage screening and study. No studies identified a voltage limit with lower transfer capability than the thermal limit for Planning Year 2024-2025.

2.2 Powerflow Models and Assumptions

2.2.1 Tools Used

MISO used the Siemens PTI Power System Simulator for Engineering (PSS/E) and PowerGEM Transmission Adequacy and Reliability Assessment (TARA) tools.

2.2.2 Inputs Required

Thermal transfer analysis requires powerflow models and related input files. MISO used contingency files from MTEP[2] reliability assessment studies. Single-element contingencies in MISO and seam areas were also evaluated.

MISO developed a subsystem file to monitor its footprint and seam areas which was used for all seasons. LRZ definitions were developed as sources and sinks in the study. See Appendix C for tables containing adjacent area definitions (Tiers 1 and 2) used for this study. The monitored file includes all facilities under MISO functional control and single elements in the seam areas of 100 kV and above.

2.2.3 Powerflow Modeling

The MTEP23 models were built using MISO's Model on Demand (MOD) model data repository, with the following base assumptions (Table 2-1).

Scenario	Effective Date	Projects Applied	External Modeling	Load and Generation Profile	Wind %	Solar %
Summer 2024	July 15th	MTEP Appendix A and Target A	ERAG MMWG 2022 Series 2024 Summer Peak Load Model	Summer Peak	18%	50%
Fall 2024	October 15th	MTEP Appendix A and Target A	ERAG MMWG 2022 Series 2024 Spring Light Load Model	Fall Peak	28.5%	0%
Winter 2024-2025	January 15th	MTEP Appendix A and Target A	ERAG MMWG 2022 Series 2024 Winter Peak Load Model	Winter Peak	67%	0%
Spring 2025	April 15th	MTEP Appendix A and Target A	ERAG MMWG 2022 Series 2024 Spring Light Load Model	Spring Peak	28.5%	0%

Table 2-1: Model Assumptions

MISO excluded several types of units from the transfer analysis dispatch—these units' base dispatch remained fixed.

- Nuclear dispatch does not change for any transfer without a sensitivity
- Wind and solar resources can be ramped down, but not up
- Pseudo-tied resources were modeled at their expected commitments to non-MISO load, although portions of these units committed to MISO could participate in transfer analyses

System conditions such as load, dispatch, topology, and interchange have an impact on transfer capability. The model was reviewed as part of the base model built for MTEP23 analyses, with study files made available on MISO ShareFile.

[2] Refer to the Transmission Planning BPM (BPM-20) for more information regarding MTEP input files. https://www.misoenergy.org/legal/business-practice-manuals/

MISO worked closely with Transmission Owners and stakeholders to model the transmission system accurately, as well as to validate constraints and redispatch. Like other planning studies, transmission outage schedules were not included in the analyses. This is driven partly by limited availability of outage information as well as current transmission planning standards. Although no outage schedules were evaluated, single element contingencies were evaluated. This includes Bulk Electric System lines, transformers, and generators.

Contingency coverage covers most of category P1 and some of category P2 outlined in Table 1 of NERC Reliability Standard TPL-001.

2.2.4 General Assumptions

MISO uses TARA to process the powerflow model and associated input files to determine the seasonal import and export limits of each LRZ by determining the transfer capability. Transfer capability measures the ability of interconnected power systems to reliably transfer power from one area to another under specified system conditions. The incremental amount of power that can be transferred is determined through FCITC analysis. FCITC analysis and base power transfers provide the information required to calculate the First Contingency Total Transfer Capability (FCTTC), which indicates the total amount of transferrable power before a constraint is identified. FCTTC is the base power transfer plus the incremental transfer capability (Equation 2-1). All published limits are based on the zone's FCTTC and may be adjusted for capacity exports.

$$First\ Contingency\ Total\ Transfer\ Capability\ (FCTTC) = Base\ Power\ Transfer + FCITC$$

Equation 2-1: Total Transfer Capability

FCITC constraints are identified under base case situations in each season or under P1 contingencies provided through the MTEP process. Linear FCITC analysis identifies the limiting constraints using a minimum transfer Distribution Factor (DF) cutoff of 3 percent, meaning the transfer must increase the loading on the overloaded element, under system intact or contingency conditions, by 3 percent or more.

A pro-rata dispatch is used, which ensures all available generators will reach their maximum dispatch level at the same time. The pro-rata dispatch is based on the MW reserve available for each unit and the cumulative MW reserve available in the subsystem. The MW reserve is found by subtracting a unit's base model generation dispatch from its maximum dispatch, which reflects the available capacity of the unit.

Table 2-2 and Equation 2-2 show an example of how one unit's dispatch is set, given all machine data for the source subsystem.

Machine	Base Model Unit Dispatch (MW)	Minimum Unit Dispatch (MW)	Maximum Unit Dispatch (MW)	Reserve MW (Unit Dispatch Max – Unit Dispatch Min)
1	20	20	100	80
2	50	10	150	100
3	20	20	100	80
4	450	0	500	50
5	500	100	500	0
			Total Reserve	**310**

Table 2-2: Example Subsystem

$$\textbf{\textit{Machine 1 Incremental Post Transfer Dispatch}} = \frac{\textbf{\textit{Machine 1 Reserve MW}}}{\textbf{\textit{Source Subsystem Reserve MW}}} \times \textbf{\textit{Transfer Level MW}}$$

$$Machine\ 1\ Incremental\ Post\ Transfer\ Dispatch = \frac{80}{310} \times 100 = 25.8$$

$$Machine\ 1\ Incremental\ Post\ Transfer\ Dispatch = 25.8$$

Equation 2-2: Machine 1 Dispatch Calculation for 100 MW Transfer

2.3 Results for CIL/CEL and ZIA/ZEA

Study constraints and associated ZIA, ZEA, CIL, and CEL for each LRZ for each season were presented and reviewed through the LOLEWG with final results for Planning Year 2024-2025 presented at the October 17th, 2023 meeting. Table 2-3 below shows the Planning Year 2024-2025 CIL and ZIA with corresponding constraint, GLT, and redispatch (RDS) information.

All zones had an identified ZIA this year. If there is no valid constraint identified, the following equation will be used where the FCITC will be replaced by the Tier 1 and Tier 2 capacity.

$$\textbf{\textit{ZIA}} = \textbf{\textit{FCITC}} + \textbf{\textit{Area Interchange}} - \textbf{\textit{Border External Resources and Coordinating Owners}}$$

Equation 2-3: Zonal Import Ability (ZIA) Calculation

LRZ1	Monitored Element	Contingency	GLT	RDS	ZIA	CIL
Summer 2024	Wien - T Corners 115 kV	Arpin - Eau Claire 345 kV	10%	826MWx2	6460	6462
Fall 2024	Mitchell County - Adams 345 kV	Sherburne Country Generator	None	977MWx2	6500	6502
Winter 2024/25	Pleasant Valley - Byron 161 kV	Byron - Pleasant Valley 345 kV	None	670MWx2	4691	4693
Spring 2025	Coal Creek CR4 - Coal Creek TP4 230 kV	Coal Creek - Stanton 230 kV	None	1000MWx2	4941	4943
LRZ2	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2024	Paddock 345/138 kV Transformer	Riverside Generator	None	586MWx2	4506	4506
Fall 2024	Arpin - Sigel 138 kV	Pow STG20 Generator	None	1000MWx2	5719	5719
Winter 2024/25	Rockdale - Lakehead Cambridge Tap 138 kV	Cambridge Tap - Rockdale 138 kV	None	614MWx2	5523	5523
Spring 2025	Arpin - Sigel 138 kV	Arpin - Rocky Run 345kV	None	1000MWx2	5034	5034
LRZ3	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2024	Ottumwa 345/161 kV Transformer	Ottumwa Generator	None	617MWx2	4911	5009
Fall 2024	Ottumwa 345/161 kV Transformer	Ottumwa Generator	None	365MWx2	6684	6789
Winter 2024/25	Sub 3458 (Nebraska City) - Sub 3456 345 kV	Sub 3455 - Sub 3740 345 kV	None	440MWx2	5600	5704
Spring 2025	Ottumwa 345/161 kV Transformer	Ottumwa Generator	None	527MWx2	6514	6626
LRZ4	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2024	None	None	20%	None	9857	10790
Fall 2024	Palmyra - Marblehead North 161 kV	Herleman - Palmyra Tap 345 kV	10%	533MWx2	5699	6637
Winter 2024/25	Palmyra 345/161 kV Transformer	Herleman - Palmyra Tap 345 kV	None	1000MWx2	5811	6731
Spring 2025	Palmyra - Marblehead North 161 kV	Herleman - Palmyra Tap 345 kV	None	1000MWx2	5083	6003
LRZ5	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2024	Moro - Miles 138 kV	Roxford - Moro 345 kV	None	1000MWx2	3208	3208
Fall 2024	Moro - Miles 138 kV	Roxford - Moro 345 kV	None	202MWx2	3786	3786
Winter 2024/25	Moro - Miles 138 kV	Roxford - Moro 345 kV	None	1000MWx2	4477	4477
Spring 2025	Moro - Miles 138 kV	Roxford - Moro 345 kV	None	356MWx2	3892	3892
LRZ6	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2024	Cayuga Sub- Cayuga 345 kV	Kansas West - Sugar Creek 345 kV	5%	712MWx2	7197	7463
Fall 2024	Cayuga Sub - Cayuga 345 kV	Kansas West - Sugar Creek 345 kV	None	282MWx2	8661	8954
Winter 2024/25	Sullivan - Petersburg 345 kV	Rockport - Jefferson 765 kV	None	890MWx2	8286	8526
Spring 2025	Lawrenceville South - Vincennes 138 kV	Albion South - Gibson 345 kV	None	294MWx2	7730	8015
LRZ7	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2024	Monroe 1&2 - Brownstown (Superior) 345kV	Monroe 1&2 - Wayne 345 kV	None	1000MWx2	4490	4500
Fall 2024	Verona - J758 138 kV	J758 - Verona West 138 kV	None	373MWx2	4390	4400
Winter 2024/25	Argenta - Tompkins 345 kV	Argenta - Battle Creek 345 kV	None	1000MWx2	4656	4666
Spring 2025	Stillwell - Dumont 345 kV	Wilton Center - Dumont 765 kV	None	927MWx2	4883	4893
LRZ8	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2024	Winnfield 230/115 kV Transformer	Montgomery - Clarence 230 kV	None	1000MWx2	3444	3536
Fall 2024	Mount Olive - Vienna 115 kV	Mount Olive - Eldorado 500 kV	None	1000MWx2	4942	5040
Winter 2024/25	Little Gypsy - Fairview 230 kV	Michoud - Front Street 230 kV	None	1000MWx2	4262	4336
Spring 2025	Winnfield 230/115 kV Transformer	Mount Olive - Layfield 500 kV	10%	1000MWx2	6030	6124
LRZ9	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2024	Danville - Dodson 115 kV	Mount Olive - Layfield 500 kV	None	1000MWx2	4794	5613
Fall 2024	Daniel - Daniel Intermediate 1 230 kV	Daniel - Daniel Intermediate 2 230 kV	None	1000MWx2	5608	6435
Winter 2024/25	Bogalusa 500/230 kV Transformer	Mcknight - Franklin 500 kV	None	1000MWx2	4623	5420
Spring 2025	Bogalusa 500/230 kV Transformer	Mcknight - Franklin 500 kV	None	1000MWx2	5598	6417
LRZ10	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2024	Perryville - Baxter Wilson 500 kV	Grand Gulf Generator	None	1000MWx2	3564	3564
Fall 2024	Mcknight - Franklin 500 kV	Baxter Willson - Perryville 500 kV	21%	929MWx2	4736	4736
Winter 2024/25	Perryville - Baxter Wilson 500 kV	Grand Gulf Generator	None	1000MWx2	3219	3219
Spring 2025	Mcknight - Franklin 500 kV	Baxter Willson - Perryville 500 kV	34%	284MWx2	4628	4628

Table 2-3: Planning Year 2024–2025 Import Limits

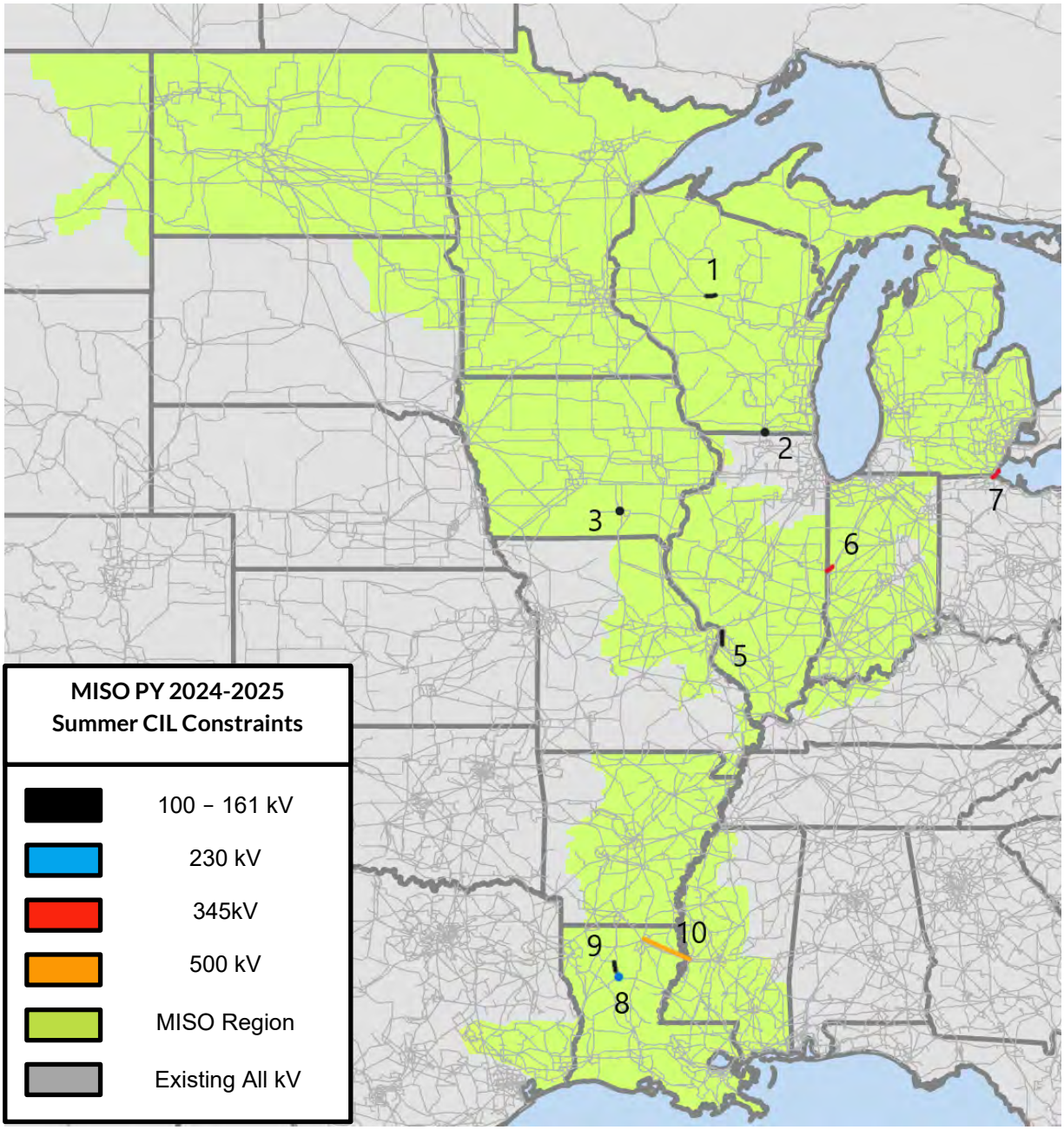


Figure 2-2: Planning Year 2024-2025 Summer Capacity Import Constraints Map

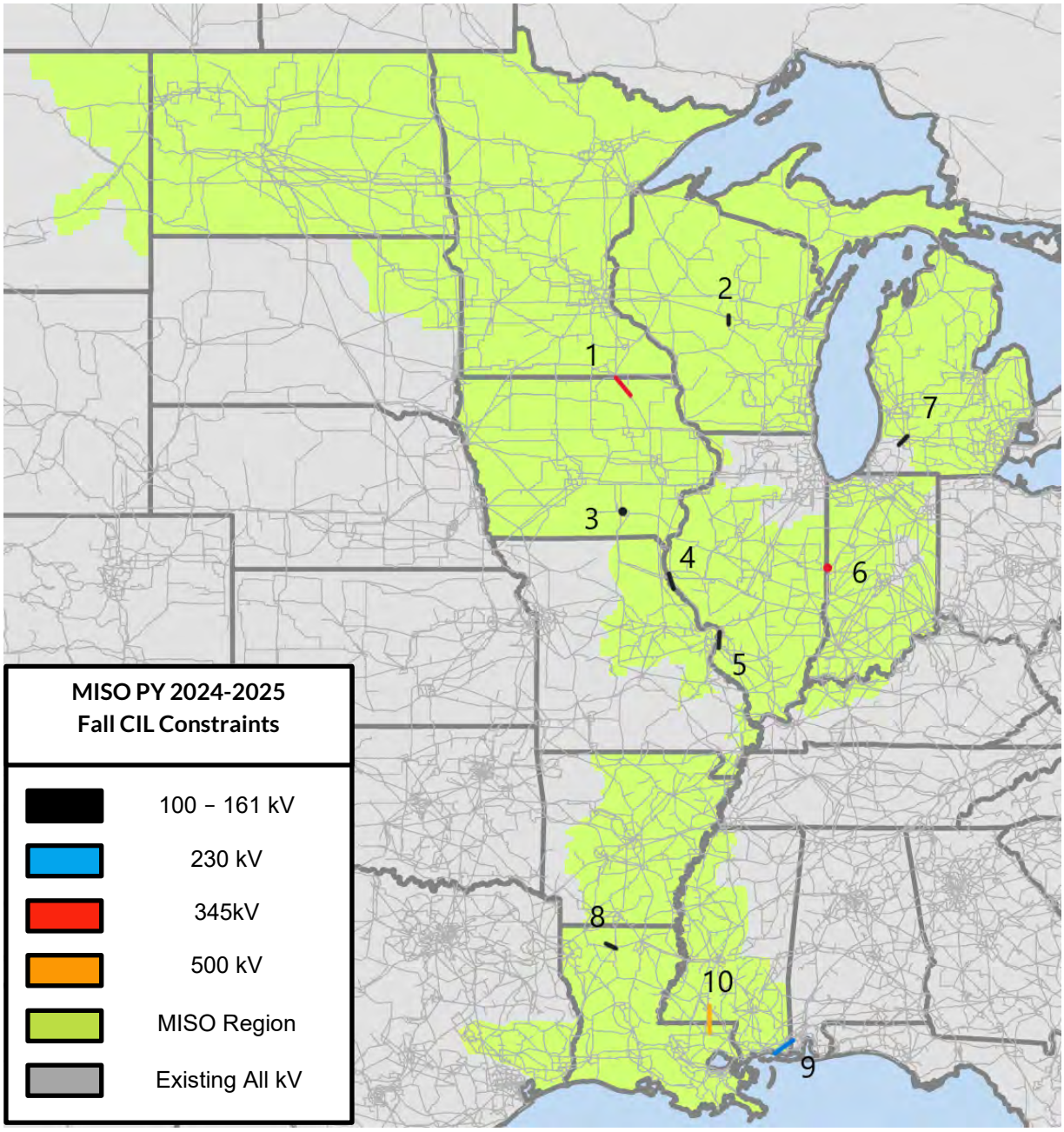


Figure 2-3: Planning Year 2024-2025 Fall Capacity Import Constraints Map

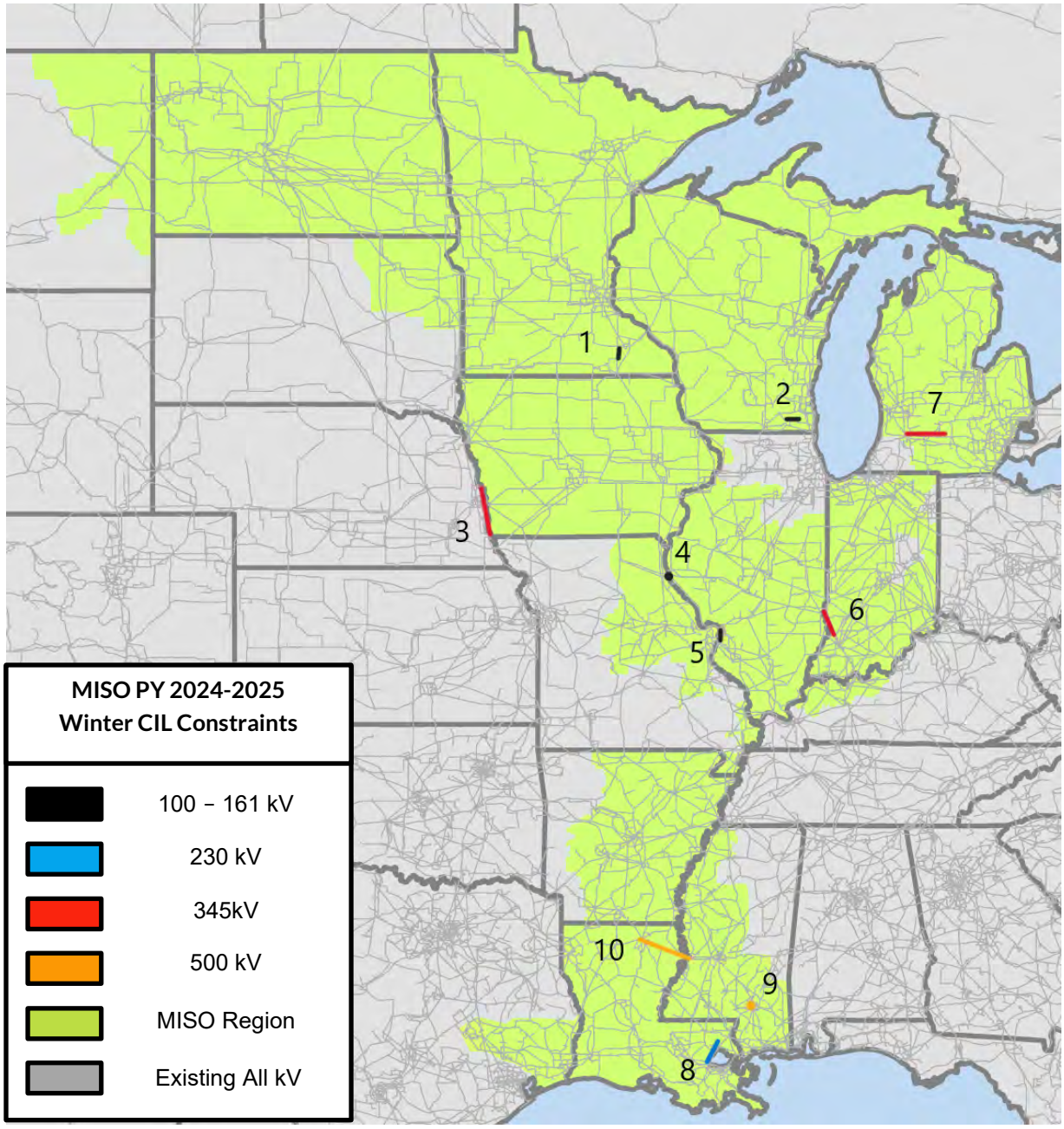


Figure 2-4: Planning Year 2024-2025 Winter Capacity Import Constraints Map

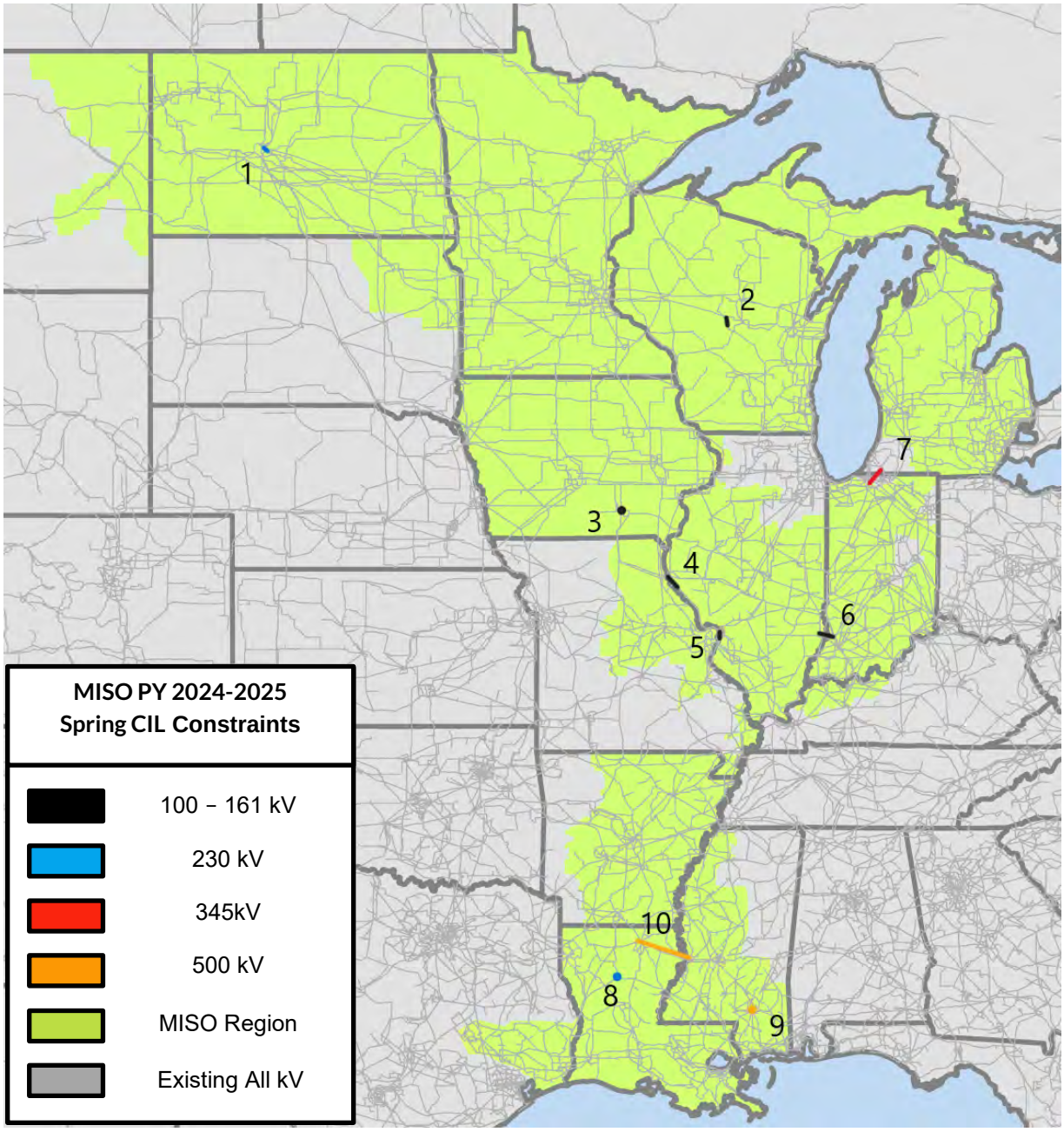


Figure 2-5: Planning Year 2024-2025 Spring Capacity Import Constraints Map

Capacity Exports Limits are found by increasing generation in the study zone and decreasing generation in the rest of the MISO footprint to create a transfer. Table 2-4 below shows the Planning Year 2024-2025 CEL and ZEA with corresponding constraint, GLT, and redispatch information.

LRZ1	Monitored Element	Contingency	GLT	RDS	ZEA	CEL
Summer 2024	Split Rock - Sioux Falls 230 kV	Split Rock - Sioux City 345 kV	10%	1000MWx2	4539	4537
Fall 2024	Arpin - Sigel 138 kV	Arpin - Rocky Run 345kV	None	302MWx2	5713	5711
Winter 2024/25	Split Rock - Sioux Falls 230 kV	Split Rock - Sioux City 345 kV	None	847MWx2	5176	5174
Spring 2025	Split Rock - Sioux Falls 230 kV	Split Rock - Sioux City 345 kV	None	194MWx2	6320	6318
LRZ2	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2024	Pleasant Prairie - Zion 345 kV	Pleasant Prairie - Zion EC 345 kV	40%	295MWx2	3971	3971
Fall 2024	Pleasant Prairie - Zion 345 kV	Pleasant Prairie - Zion EC 345 kV	None	936MWx2	4512	4512
Winter 2024/25	Pleasant Prairie - Zion EC 345 kV	Pleasant Prairie - Zion 345 kV	30%	1000MWx2	4772	4772
Spring 2025	Pleasant Prairie - Zion EC 345 kV	Pleasant Prairie - Zion 345 kV	None	1000MWx2	4601	4601
LRZ3	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2024	None	None	50%	None	5548	5450
Fall 2024	Sandburg 161/138 kV Transformer	Galesburg - Oak Grove 345 kV	40%	515MWx2	7018	6913
Winter 2024/25	Wapello County - Appanoose County 161 kV	Zachary - Hughes 345kV	None	1000MWx2	9079	8975
Spring 2025	Sandburg 161/138 kV Transformer	Galesburg - Oak Grove 345 kV	50%	285MWx2	5873	5761
LRZ4	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2024	None	None	50%	None	3663	2730
Fall 2024	None	None	50%	None	4801	3863
Winter 2024/25	None	None	50%	None	5570	4650
Spring 2025	None	None	50%	None	6001	5081
LRZ5	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2024	None	None	40%	None	4644	4644
Fall 2024	Mass 345/161 kV Transformer	Mass - Joppa 345 kV	None	360MWx2	5402	5402
Winter 2024/25	None	None	50%	None	6229	6229
Spring 2025	Mass 345/161 kV Transformer	Shawnee - Mass 345 kV	None	1000MWx2	4984	4984
LRZ6	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2024	BR Tap - Paradise 161 kV	Paradise - Paradise CC Units 3-4 161 kV	35%	93MWx2	5903	5637
Fall 2024	South - Southeast 138 kV	Hanna - Franklin Township 138 kV	None	624MWx2	3812	3519
Winter 2024/25	Grandview - Newtonville 138 kV	Daviess - Coleman EHV Substation 345 kV	None	388MWx2	1647	1407
Spring 2025	South - Southeast 138 kV	Hanna - Franklin Township 138 kV	None	575MWx2	3729	3444
LRZ7	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2024	Lallendorf - Fostoria Central 345 kV	Lemoyne - Fostoria Central 345 kV	30%	921MWx2	5719	5709
Fall 2024	Monroe 1&2 - Lallendorf 345 kV	Morocco - Allen Jct 345 kV	None	1000MWx2	5391	5381
Winter 2024/25	Morocco - Allen Jct 345 kV	Lallendorf - Monroe 345 kV	None	1000MWx2	5753	5743
Spring 2025	Monroe 1&2 - Lallendorf 345 kV	Morocco - Allen Jct 345 kV	None	564MWx2	5601	5591
LRZ8	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2024	Perryville - Baxter Wilson 500 kV	Grand Gulf Generator	30%	1000MWx2	6263	6171
Fall 2024	Independence - Moorefield 161 kV	Independence - Power Line Road EHV 500 kV	None	35MWx2	4310	4212
Winter 2024/25	Arklahoma - Hot Springs East 115 kV	Hot Springs West - Arklahoma 115 kV	50%	155MWx2	5882	5808
Spring 2025	Cash - Jonesboro 161 kV	Independence - Power Line Road EHV 500 kV	None	177MWx2	5030	4936
LRZ9	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2024	PPG - Verdine 230 kV	PPG - Manena 230 kV	None	1000MWx2	3178	2359
Fall 2024	White Bluff - Keo 500 kV	Sheridan - Mabelvale 500 kV	None	1000MWx2	4429	3602
Winter 2024/25	Adams Creek - Angie 230 kV	French Branch - Slidell 230 kV	None	1000MWx2	2900	2103
Spring 2025	Michoud - Front Street 230 kV	Mcknight - Franklin 500 kV	None	1000MWx2	4813	3994
LRZ10	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2024	Clarksdale - Lyon 115 kV	MEPS Clarkesdale - Moon Lake 230kV	None	377MWx2	1840	1840
Fall 2024	Clarksdale - Lyon 115 kV	MEPS Clarkesdale - Moon Lake 230kV	None	535MWx2	2889	2889
Winter 2024/25	Clarksdale - Lyon 115 kV	MEPS Clarkesdale - Moon Lake 230kV	None	284MWx2	2993	2993
Spring 2025	Clarksdale - Lyon 115 kV	MEPS Clarkesdale - Moon Lake 230kV	None	535MWx2	2740	2740

Table 2-4: Planning Year 2024–2025 Export Limits

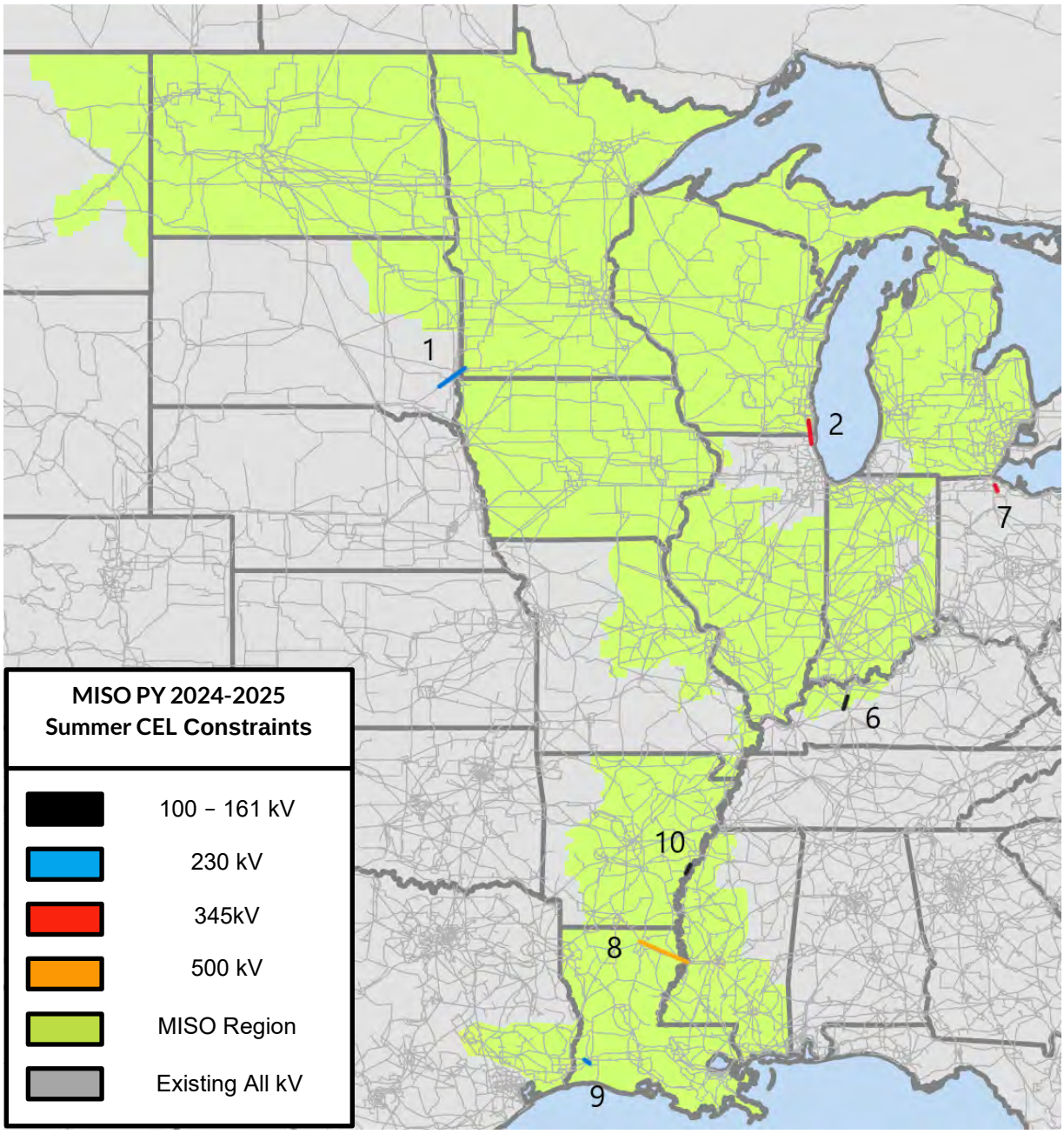


Figure 2-6: Planning Year 2024-2025 Summer Export Constraint Map

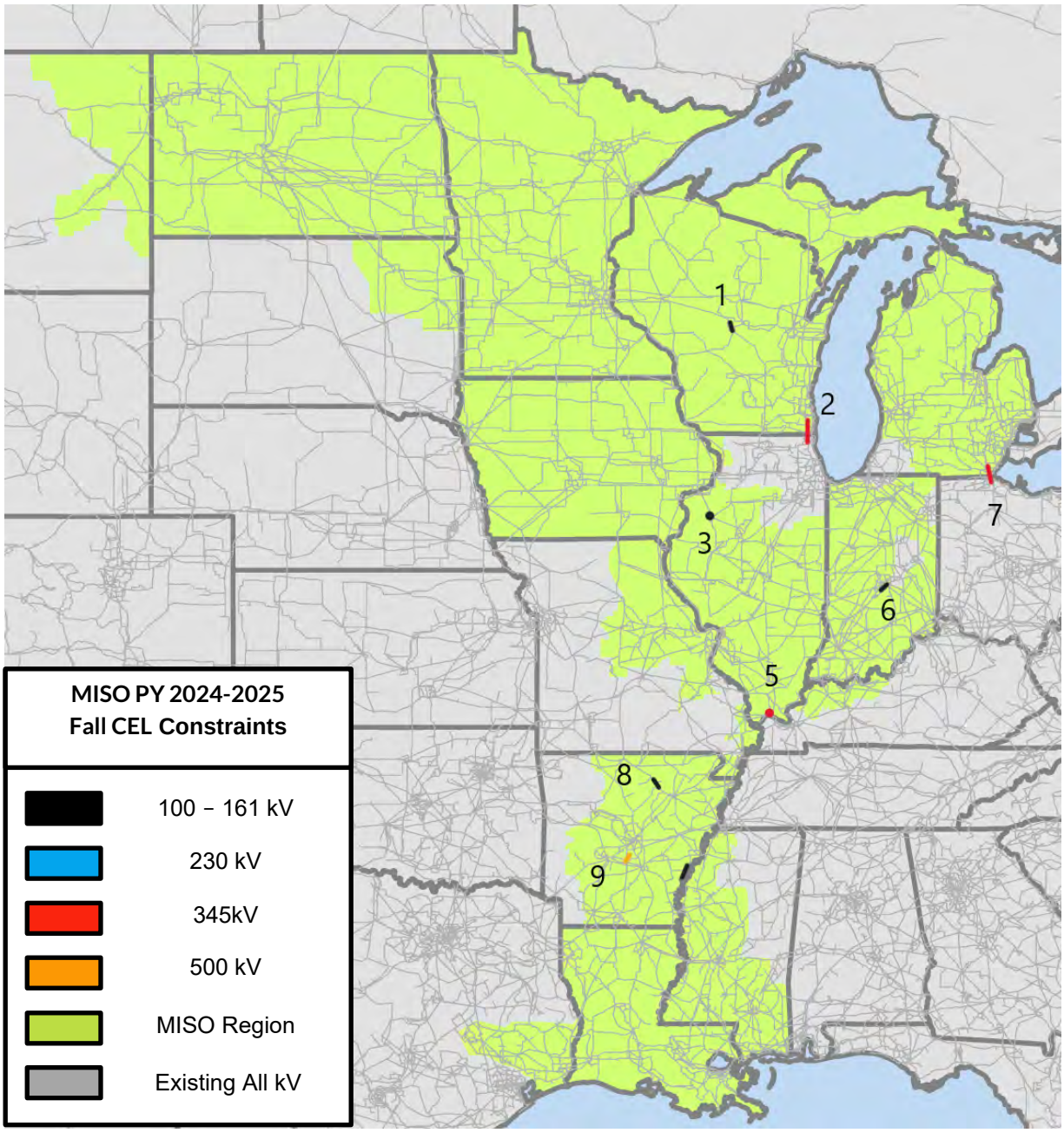


Figure 2-7: Planning Year 2024-2025 Fall Export Constraint Map

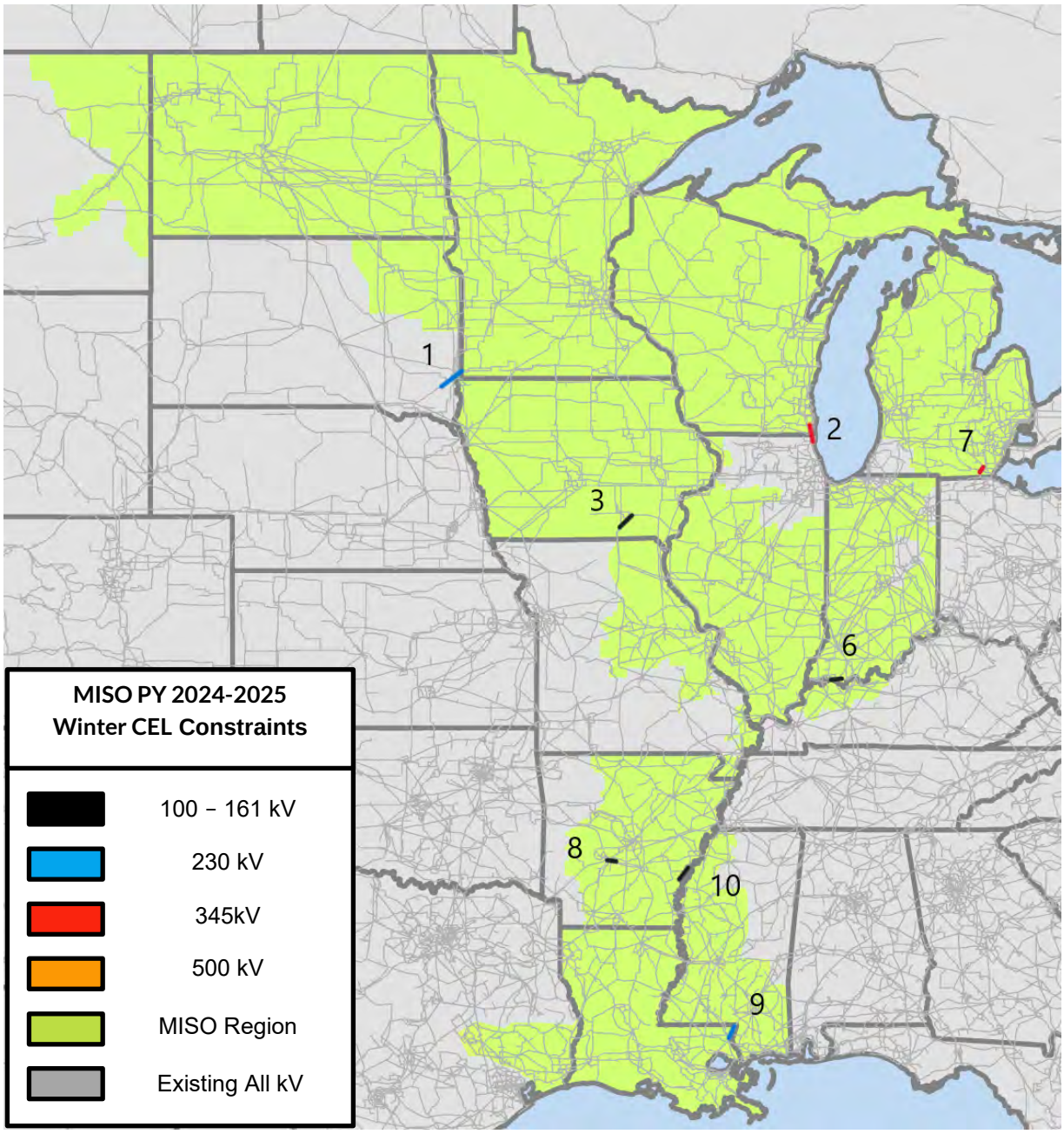


Figure 2-8: Planning Year 2024-2025 Winter Export Constraint Map

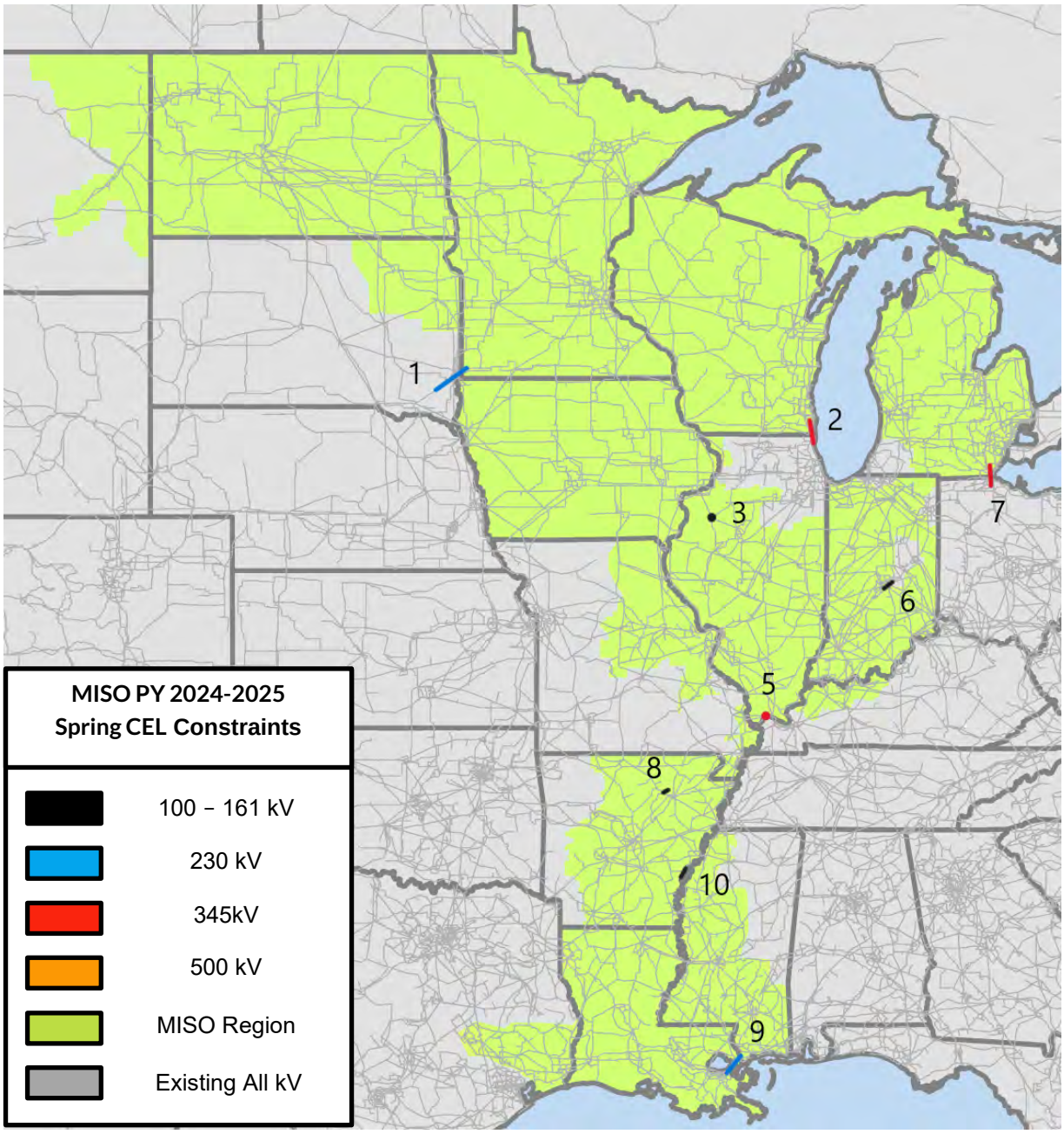


Figure 2-9: Planning Year 2024-2025 Spring Export Constraint Map

3 Loss of Load Expectation Analysis

3.1 LOLE Modeling Input Data and Assumptions

MISO uses a program developed and maintained by Astrapé Consulting called Strategic Energy & Risk Valuation Model (SERVM) to calculate LOLE for the applicable Planning Year. SERVM uses a sequential Monte Carlo simulation to model a generation system and to assess the system's reliability, based on any number of interconnected areas. SERVM calculates LOLE for the MISO system and for each LRZ by stepping through the year chronologically and taking into account generation, load, load modifying and energy efficiency resources, equipment forced outages, planned and maintenance outages, weather and economic uncertainty, and external support.

Building the SERVM model is the most time-consuming task of the LOLE Study. Several sensitivities are built in order to determine how specific inputs and variables impact the results. The base case models determine the seasonal MISO PRM Installed Capacity (ICAP), PRM Unforced Capacity (UCAP), and the Local Reliability Requirements (LRRs) for each LRZ for future Planning Years one, four, and six.

3.2 MISO Generation

3.2.1 Thermal Units

The Planning Year 2024-2025 LOLE Study used the 2023-2024 PRA converted capacity as a starting point for which resources to include in the study. This ensured that only resources eligible as Planning Resources were included in the LOLE Study. An exception was made to include resources with a signed and executed GIA that have an anticipated in-service date (adjusted for average GI delays) for PY 2024-2025. All internal Planning Resources were modeled in the LRZ in which they are physically located. Additionally, Coordinating Owner External Resources and Border External Resources were modeled as being internal to the LRZ in which they are committed to serving load.

Seasonal forced outage rates and annualized planned maintenance outage rates were calculated over a five-year period (January 2016 to December 2022) for each resource. Some resources did not have five years of historical data in MISO's Generator Availability Data System (PowerGADS)—however, if they had at least 3 consecutive months of outage data, resource-specific information was used to calculate their seasonal forced and planned maintenance outage rates. Resources with fewer than 3 consecutive months of resource-specific outage data were assigned the corresponding MISO seasonal class average forced outage rate and annualized planned maintenance outage rate based on their resource type. The overall MISO ICAP-weighted seasonal class average forced outage rates and annualized planned maintenance outage rate were applied in lieu of class averages for classes with fewer than 30 resources reporting 12 or more months of data.

Each nuclear unit has a fixed maintenance schedule, which was pulled from publicly available information and was modeled for each of the study years.

The historical class average outage rates as well as the MISO system-wide weighted average forced outage rate are provided in Table 3-1 to show the year-over-year trends, as well as in Table 3-2 on a seasonal basis.

Pooled EFORd GADS Years	2018-2022 (%)	2017-2021 (%)	2016-2020 (%)	2015-2019 (%)	2014-2018 (%)	2013-2017 (%)
LOLE Study Planning Year	**PY 2024-2025** Summer	**PY 2023-2024** Summer	**PY 2022-2023** Annualized	**PY 2021-2022** Annualized	**PY 2020-2021** Annualized	**PY 2019-2020** Annualized
Combined Cycle	5.92	5.54	5.85	5.52	5.70	5.37
Combustion Turbine (0-20 MW)	24.42	23.40	35.20	36.38	40.39	23.18
Combustion Turbine (20-50 MW)	6.54	6.30	13.65	14.20	15.29	15.76
Combustion Turbine (50+ MW)	4.88	4.07	4.36	4.76	4.65	5.18
Diesel Engines	17.14	12.79	7.25	10.05	23.53	10.26
Fluidized Bed Combustion	*	*	*	*	*	*
Hydro (0-30 MW)	*	*	*	*	*	*
Hydro (30+ MW)	*	*	*	*	*	*
Nuclear	*	*	*	*	*	*
Pumped Storage	*	*	*	*	*	*
Steam – Coal (0-200 MW)	7.91	6.34	8.72	7.12	6.34	5.83
Steam - Coal (200-600 MW)	7.81	7.57	10.27	10.20	9.85	9.60
Steam - Coal (600-1,000 MW)	9.57	8.47	8.83	8.38	8.41	8.05
Steam - Gas	14.04	12.48	11.84	12.91	12.54	11.56
Steam - Oil	*	*	*	*	*	*
Steam - Waste Heat	*	*	*	*	*	*
Steam - Wood	*	*	*	*	*	*
MISO Weighted System-wide	8.24	8.23	9.04	9.36	9.24	9.28

Table 3-1: Historical Class Average Forced Outage Rates

Pooled EFORd GADS Years	2018-2022 (%)	2018-2022 (%)	2018-2022 (%)	2018-2022 (%)
LOLE Study Planning Year 2024-2025	**Summer 2024**	**Fall 2024**	**Winter 2024-2025**	**Spring 2025**
Combined Cycle	5.92	7.43	5.38	6.55
Combustion Turbine (0-20 MW)	24.42	24.17	46.17	51.36
Combustion Turbine (20-50 MW)	6.54	18.59	50.59	34.26
Combustion Turbine (50+ MW)	4.88	7.23	10.53	5.15
Diesel Engines	17.14	14.26	24.94	8.89
Fluidized Bed Combustion	*	*	*	*
Hydro (0-30 MW)	*	*	*	*
Hydro (30+ MW)	*	*	*	*
Nuclear	*	*	*	*
Pumped Storage	*	*	*	*
Steam – Coal (0-200 MW)	7.91	9.69	8.71	11.85
Steam - Coal (200-600 MW)	7.81	10.91	9.07	8.28
Steam - Coal (600-1,000 MW)	9.57	7.78	10.32	11.41
Steam - Gas	14.04	13.26	11.11	12.07
Steam - Oil	*	*	*	*
Steam - Waste Heat	*	*	*	*
Steam - Wood	*	*	*	*
MISO Weighted System-wide	8.24	9.15	11.23	10.33

Table 3-2: Planning Year 2024-2025 Seasonal Class Average Forced Outage Rates

3.2.2 Behind-the-Meter Generation

Behind-the-Meter Generation data came from the Module E Capacity Tracking (MECT) tool. Behind-the-Meter Generation backed by thermal resources were explicitly modeled just as any other thermal generator with a monthly capability and forced outage rate. Behind-the-Meter Generation backed by intermittent resources were modeled at their expected seasonal availability.

3.2.3 Attachment Y

MISO obtained information on generating resources with approved suspensions or retirements (as of June 1, 2023) through MISO's Attachment Y process. Any resource with an approved retirement or suspension in Planning Year 2024-2025 was excluded from the year-one analysis during the months the resource has been approved to be out of service for. This same methodology is used for the four- and six-year analyses.

3.2.4 Future Generation

The LOLE model included resources with a signed and executed Generator Interconnection Agreement (as of June 1, 2022). These future resources were assigned seasonal class average forced outage rates and planned maintenance outage rates based on their resource class. Future thermal generation and upgrades were added to the LOLE model based on resource information in the MISO Generator Interconnection Queue. Resources with a planned upgrade during the study period reflect the megawatt increase for each month, beginning the month the upgrade is expected to be completed. The LOLE analysis includes future wind and solar generation, tied to the same hourly wind and solar profiles used for existing wind and solar resources in the model.

3.2.5 Intermittent Resources

Intermittent resources include solar, wind, biomass, battery storage, and run-of-river hydro. Most intermittent resources submit historical output data during seasonal peak hours, defined as hours ending 15, 16, & 17 EST for Summer, Fall, and Spring, and hours ending 8, 9, 19, & 20 for Winter. Non-CPNode wind and battery storage resources are exceptions to this and only submit historical output data for the top 8 seasonal coincident peaks for the last 3 Planning Years for which data is available. This data is averaged at the seasonal level and modeled in the LOLE analysis as seasonal effective capacity for all months within a given season. Each individual resource is modeled in the LRZ corresponding to its load obligation.

Using historical wind operational data from 253 front-of-meter wind resources from 2013 to 2022, normalized hourly capacity profiles were developed and aggregated at the LRZ level to represent hourly wind capability in the model. As a result of the LOLE analysis being based on 30 weather years (1993 – 2022), synthetic shapes were developed by Astrapé for the 1992 – 2013 period based on historical wind performance and temperatures. Once the weather and wind performance matching has been performed, the data is analyzed as a function of load to ensure the variability around the load profiles is reasonable.

Solar profiles were also developed by Astrapé using historical solar irradiance data from the NREL National Solar Radiation Database (NSRDB) from 1998 – 2022.

For more details on profile development methodology, refer to the supporting documentation Astrapé provided stakeholders at the LOLEWG detailing the development of the wind and solar profiles:
MISO Seasonal Inputs for the 2022 LOLE Study

3.2.6 Demand Response

Demand response programs and their corresponding capabilities came from the MECT tool. These resources were explicitly modeled as dispatch-limited resources. Each demand response program was modeled individually with a monthly capacity, limited by duration and the number of times each program can be called upon for each season.

3.3 MISO Load Data

The Planning Year 2024-2025 LOLE analysis used a load training process with neural net software to establish a correlated relationship in the trained and predicted load shapes between historical weather and load data. This relationship was then applied to 30 years of hourly historical load data to create 30 different load shapes for each LRZ to capture both load diversity and seasonal variations. The Zonal Coincident Peak Forecasts provided by the Load Serving Entities were used to develop zonal- and monthly-specific load forecast scaling factors which scale the average of the 30 load shapes based on provided forecasts. The results of this process are shown as the MISO System Peak Demand (Table 4-1) and LRZ Peak Demands (Table 5-1, Table 5-2, Table 5-3, & Table5-4).

Direct Control Load Management and Interruptible Demand types of demand response were explicitly included in the LOLE model as resources. Demand response is dispatched in the LOLE model to avoid load shed during simulation when all other available generation has been exhausted.

3.3.1 Weather Uncertainty

MISO has adopted a six-step load training process in order to capture the weather uncertainty associated with the most recent 50/50 load forecasts submitted by the Load Serving Entities for the development of the 30 years of hourly zonal correlated load and weather shapes in the LOLE model.

The first step of the load training process is to collect the most recent year of historical hourly net load data, as well as any hourly load reductions. Since Load Modifying Resources are modeled in the LOLE Study, the hourly load reductions are added to the net load data. MISO also collects historical temperature data from a zonal-specific weather station for the most recent weather year included in the study. Both the hourly LMR deployment and load data are taken from historical MISO energy market data for each LBA, while the historical weather data is collected from the National Oceanic and Atmospheric Administration (NOAA) for each LRZ. After collecting the data, the hourly gross load for each LRZ is calculated using the most recent five years of historical data.

The second step of the process is to normalize the five years of load data to consistent economics. This process involves zonal load growth adjustments by comparing the most recent 5 years of historical load at extreme temperatures and shifting the shapes up or down if they do not reasonably overlay on top of each other. Regression analysis is then performed at the zonal level, focusing on Summer and Winter peak periods in order to compensate for the fact that the neural net training software can occasionally over- or under-predict results for extremely high or extremely low temperatures.

The third step of the process utilizes neural net software to establish functional relationships between the most recent five years of historical weather and load data. After the load growth adjustments and regressions have been performed, the treated historical load and weather data are input into the neural net software. MISO utilizes the NeuroShell Predictor software which performs neural net training and predicting using a genetic algorithm. The neural net trains each month of zonal data individually to predict a total of 120 datasets.

In the fourth step of the process and after the neural net has finished, we check the results of the neural net at extreme temperatures to smooth out any over- or under-predicted loads by comparing against the entire 30 years of

historical correlated load and weather years. MISO looks for hours where the load is plus or minus 30% different than the previous hour and corrects those hours.

In the fifth step of the load training process, MISO undertakes extreme temperature verification on the 30 years of load shapes to ensure that the hourly load data is reasonably accurate at extremely hot or cold temperatures. This is required since there are fewer data points available at the temperature extremes when determining the neural net functional relationships. This lack of data at the extremes can result in inaccurate predictions when creating load shapes, which will need to be corrected before moving forward.

The sixth and final step of the load training process is to average the monthly peak loads of the predicted load shapes and adjust them to match each LRZ's monthly Zonal Coincident Peak Forecast provided by the Load Serving Entities for each of the study years. To calculate this adjustment, the ratio of the first year's Non-Coincident Peak Forecast to the Zonal Coincident Peak Forecast is applied to future outyears' Non-Coincident Peak Forecasts.

By adopting this methodology for capturing weather uncertainty, MISO can model multiple load shapes based on a functional relationship with weather. This modeling approach provides diversity in the load shapes, as well as in the peak loads observed within each load shape. This approach also provides the ability to capture the frequency and duration of historical severe weather patterns.

3.3.2 Economic Load Uncertainty

To account for economic load uncertainty in the Planning Year 2024-2025 LOLE model, MISO utilized a normal distribution of electric utility forecast error accounting for projected and actual Gross Domestic Product (GDP), as well as electricity usage. The historic projections for GDP growth were taken from the Congressional Budget Office (CBO), the actual GDP growth was taken from the Bureau of Economic Analysis (BEA), and the electricity usage was taken from the U.S. Energy Information Administration (EIA). Due to a lack of state-wide projected GDP data, MISO relied on aggregated United States data when calculating economic uncertainty.

To calculate the electric utility forecast error, MISO first calculated the forecast error of GDP between historical projections and actual values. The resulting GDP forecast error was then translated into electric utility forecast error by multiplying by the rate at which electric load grows in comparison to GDP. Finally, a standard deviation is calculated from the electric utility forecast error and used to create a normal distribution representing the probabilities of the load forecast errors (LFE) as shown in Table 3-3.

	LFE Levels				
	-2.0%	-1.0%	0.0%	1.0%	2.0%
Standard Deviation in LFE	Probability assigned to each LFE				
0.90%	4.8%	24.1%	42.1%	24.1%	4.8%

Table 3-3: Economic Uncertainty

3.4 External System

Firm imports from external areas to MISO are modeled at the individual resource level. The specific firm external resources were modeled with their Installed Capacity amount and their corresponding seasonal forced outage rates, or at the contracted capacity from their corresponding Power Purchase Agreement (PPA). These resources are only modeled within the system-wide MISO PRM analysis and are not modeled when calculating the zonal LRRs, as the determination of the Local Reliability Requirements is an island-type analysis. Border External Resources and Coordinating Owner External Resources are modeled as internal MISO units and are included in the PRM and LRR analyses. The external resources included as firm imports in the LOLE Study were based on the amount of capacity that was either part of a Fixed Resource Adequacy Plan (FRAP) or that offered and cleared in the Planning Year 2023-2024 Planning Resource Auction (PRA).

The LOLE analyses incorporate firm exports from MISO internal units to neighboring regions, where information was available. For units with capacity sold off-system, their monthly capacities were reduced by the megawatt amount exported. These values came from PJM's Reliability Pricing Model (RPM) as well as information on exports to other external areas taken from the Independent Market Monitor (IMM) exclusion list.

Firm exports from MISO to external areas were modeled the same as in previous years. Capacity ineligible as MISO capacity due to transactions with external areas was removed from the model. Table 3-4 shows the amount of firm imports and exports in this year's study. MISO went from being a net firm exporter to a net firm importer in the most recent PRA.

Contracts	Summer ICAP (MW)	Summer UCAP (MW)	Fall ICAP (MW)	Fall UCAP (MW)	Winter ICAP (MW)	Winter UCAP (MW)	Spring ICAP (MW)	Spring UCAP (MW)
Imports (MW)	3,217	3,052	2,865	2,758	3,771	3,613	3,247	3,105
Exports (MW)	1,142	1,086	1,160	1,124	1,125	1,062	1,159	1,094
Net	**2,075**	**1,966**	**1,705**	**1,634**	**2,646**	**2,552**	**2,088**	**2,010**

Table 3-4: Planning Year 2023-2024 Firm Imports and Exports

Non-firm imports in the Planning Year 2024-2025 LOLE Study were modeled as a probabilistic distribution of capacity value. These distributions were developed using historic seasonal NSI data which accounted for imports into MISO during emergency pricing hours. Firm imports cleared in the PRA for each Planning Year were subtracted from the NSI data to isolate the non-firm values. An additional region was included in SERVM which contained 12,000 MW of perfect generation connected to the MISO system. A distribution of the region's export capability was modeled to the upper and lower bounds. As SERVM steps through the hourly simulation, random draws on the export limits of the external region were used to represent the amount of capacity MISO could import to meet peak demand. The probability distribution of non-firm external imports used in the LOLE model has been provided in Table 3-5.

	Summer	Fall	Winter	Spring
p5	1,138	525	9	1,384
p10	1,440	903	288	1,626
p25	2,959	1,749	1,223	2,283
p50	4,260	2,601	3,292	3,717
p75	5,198	3,632	5,785	4,987
p90	5,921	4,935	8,097	6,221
p95	6,520	5,748	9,197	6,497

Table 3-5: Non-Firm External Import Distribution During Emergency Pricing Hours (MW)

3.5 Loss of Load Expectation Analysis and Metric Calculations

Upon completion of the annual LOLE Study model refresh, MISO performed probabilistic analyses to determine the seasonal PRM ICAP and PRM UCAP for Planning Year 2024-2025 as well as the seasonal Local Reliability Requirement for each of the ten Local Resource Zones. These metrics were derived through probabilistic modeling of the system, first solving to the industry standard annual LOLE risk target of 1 day in 10 years, or 0.1 day per year, and then solving to the minimum seasonal LOLE criteria of 0.01 LOLE for seasons demonstrating minimal risk.

3.5.1 Seasonal LOLE Distribution

To determine the seasonal LOLE distribution that will be used to calculate the PRM and LRRs, MISO followed the process described in Section 68A.2.1 of Module E-1 of the MISO Tariff. This process involves first solving the LOLE model to an annual value of 0.1 and then checking the seasonal distribution of the annual LOLE of 0.1. If a season had a LOLE value of at least 0.01, then it met the minimum seasonal LOLE criteria and would be set to that LOLE. If a season had less than 0.01 LOLE, additional simulations were performed until the minimum seasonal LOLE criteria of 0.01 was met.

Example: Assume the model is solved to an annual LOLE of 0.1 with 0.05 occurring in both Summer and Winter while Fall and Spring had LOLE values of 0 from this simulation. In this case, the Summer and Winter seasons would not need additional analysis since both had at least 0.01 LOLE naturally when the model was solved to an annual value of

0.1. Since Fall and Spring had 0 LOLE, they would be assigned the minimum seasonal LOLE criteria of 0.01 and additional LOLE simulations would be performed until the minimum seasonal LOLE criteria was met.

The annual distribution of LOLE across the four seasons at the industry standard of 1 day in 10 years, or 0.1 day per year, determined through the Planning Year 2024-2025 LOLE Study are shown in Table 3-6. The MISO-wide distribution results from the PRM analysis and the zonal distributions result from the LRR analyses.

Region	Summer	Fall	Winter	Spring
MISO-wide	0.1	0.01	0.01	0.01
LRZ 1	0.094	0.01	0.01	0.01
LRZ 2	0.099	0.01	0.01	0.01
LRZ 3	0.091	0.01	0.01	0.01
LRZ 4	0.022	0.01	0.075	0.01
LRZ 5	0.01	0.01	0.083	0.01
LRZ 6	0.085	0.01	0.015	0.01
LRZ 7	0.037	0.061	0.01	0.01
LRZ 8	0.014	0.01	0.078	0.01
LRZ 9	0.042	0.036	0.014	0.01
LRZ 10	0.058	0.019	0.015	0.01

Table 3-6: Planning Year 2024-2025 Seasonal LOLE Distribution

3.5.2 MISO-Wide LOLE Analysis and PRM Calculation

MISO determines the appropriate PRM for each season of the applicable Planning Year based upon probabilistic analysis of reliably serving expected demand. The probabilistic analysis will utilize a Loss of Load Expectation (LOLE) study which assumes that there are no internal transmission limitations.

To determine the PRM, the LOLE model will initially be run with no adjustments to the capacity. If the LOLE is less than the minimum seasonal LOLE criteria, a negative output unit with no outage rates will be added until the LOLE reaches the minimum seasonal LOLE criteria. This is comparable to adding load to the model. If the LOLE is greater than the minimum seasonal LOLE criteria, proxy units based on a typical combustion turbine unit of 160 MW with class average seasonal forced outage rates will be added to the model until the LOLE reaches the minimum seasonal LOLE criteria.

MISO's annual LOLE Study will calculate the seasonal PRMs based on the LOLE criteria identified in the previous section. The minimum seasonal PRM requirement will be determined using the LOLE analysis by either adding a perfectly available negative output unit or by adding proxy units until a minimum LOLE of 0.01 day per season is reached.

The formulas for the PRM values for the MISO system are:

PRM ICAP % = (Installed Capacity + Firm External Support ICAP + ICAP Adjustment to meet LOLE target – MISO Coincident Peak Demand)/MISO Coincident Peak Demand

PRM UCAP % = (Unforced Capacity + Firm External Support UCAP + UCAP Adjustment to meet LOLE target – MISO Coincident Peak Demand)/MISO Coincident Peak Demand

Where Unforced Capacity (UCAP) = Installed Capacity (ICAP) x (1 – XEFORd)

3.5.3 LRZ LOLE Analysis and Local Reliability Requirement Calculation

For the Local Resource Zone analysis, each zone included only the generating units within the LRZ (including Coordinating Owner External Resources and Border External Resources) and was modeled without consideration of the benefit of the LRZ's import capability. Similar to the MISO PRM analysis, Unforced Capacity is either added or removed in each LRZ such that an LOLE of 0.1 day per year is achieved when solving for the annual target and a minimum LOLE at least 0.01 day per season when solving for the minimum seasonal LOLE criteria. The minimum amount of Unforced Capacity above each LRZ's seasonal peak demand that was required to meet the reliability criteria was used to establish each LRZ's LRR.

The Planning Year 2024-2025 seasonal LRRs were determined using the LOLE analysis by first either adding or removing capacity until the annual LOLE reaches 0.1 day per year for the LRZ. If the LOLE is less than 0.1 day per year, a perfectly available negative output unit with no outage rates will be added until the LOLE reaches 0.1 day per year. If the LOLE is greater than 0.1 day per year, proxy units based on a typical combustion turbine unit of 160 MW with class average seasonal forced outage rates will be added to the model until the LOLE reaches 0.1 day per year.

After solving each LRZ for to the annual LOLE target of 0.1 day per year, MISO will calculate each seasonal LRR such that the summation of seasonal LOLE across the year in each zone is 1 day in 10 years, or 0.1 day per year. A minimum seasonal LOLE criteria of 0.01 will be used to calculate the LRR in seasons with less than 0.01 LOLE risk under the annual case. The seasonal Local Reliability Requirement will be determined using the LOLE analysis by either adding a perfectly available negative output unit or by adding proxy combustion turbine units until a minimum LOLE of 0.01 day per season is reached. When needed, a fraction of the marginal proxy unit was added to achieve the exact minimum seasonal LOLE criteria for the LRZ.

LRR UCAP % = (Unforced Capacity + UCAP Adjustment to meet LOLE target – Zonal Coincident Peak Demand)/Zonal Coincident Peak Demand

4 MISO System Planning Reserve Margin

4.1 Planning Year 2024-2025 MISO Planning Reserve Margin Results

For Planning Year 2024-2025, the ratio of MISO capacity to forecasted MISO system peak demand yielded a Planning Reserve Margin ICAP of 17.7 percent and a Planning Reserve Margin UCAP of 9.0 percent for the Summer season. Numerous values and calculations went into determining the MISO system PRM ICAP and PRM UCAP (Table 4-1).

MISO Planning Reserve Margin (PRM)	PY 2024-2025 Summer	PY 2024-2025 Fall	PY 2024-2025 Winter	PY 2024-2025 Spring	Formula Key
MISO System Peak Demand (MW)	124,669	112,232	104,303	99,496	[A]
Installed Capacity (ICAP) (MW)	150,187	148,755	165,924	152,092	[B]
Unforced Capacity (UCAP) (MW)	139,444	136,572	143,201	138,251	[C]
Firm External Support ICAP (MW)	3,217	2,865	3,771	3,247	[D]
Firm External Support UCAP (MW)	3,052	2,758	3,613	3,105	[E]
Adjustment to ICAP (MW)	(6,650)	(11,145)	(13,890)	(15,275)	[F]
Adjustment to UCAP (MW)	(6,650)	(11,145)	(13,890)	(15,275)	[G]
ICAP PRM Requirement (PRMR) (MW)	146,754	140,475	155,805	140,064	[H] = [B]+[D]+[F]
UCAP PRM Requirement (PRMR) (MW)	135,846	128,185	132,925	126,081	[I] = [C]+[E]+[G]
MISO PRM ICAP	**17.7%**	**25.2%**	**49.4%**	**40.8%**	[J]=[H]-[A]/[A]
MISO PRM UCAP	**9.0%**	**14.2%**	**27.4%**	**26.7%**	[K]=[I]-[A]/[A]

Table 4-1: Planning Year 2024-2025 MISO System Planning Reserve Margins

4.1.1 Additional Risk Metric Statistics

In addition to the LOLE results, SERVM has the ability to calculate several other probabilistic metrics, shown below in Table 4-2. The values for Loss of Load Hours (LOLH) and Expected Unserved Energy (EUE) are calculated at the point where the annual LOLE is at 1 day in 10 years, or 0.1 LOLE. Loss of Load Hours is defined as the number of hours during a given time period where system demand will exceed the generating capacity. Expected Unserved Energy is energy-centric and analyzes all hours of a particular Planning Year. Results are calculated in megawatt-hours (MWh). EUE is the summation of the expected number of MWh of load that will not be served in a given Planning Year as a result of demand exceeding the available generation across all deficient hours.

MISO LOLE Statistics	
Loss of Load Expectation (LOLE) [days/year]	0.100
Loss of Load Hours (LOLH) [hours/year]	0.289
Expected Unserved Energy (EUE) [megawatt-hours/year]	989.451

Table 4-2: Additional Risk Metric Statistics

4.2 Comparison of PRM Targets Across 10 Years

Figure 4-1 compares the PRM UCAP values over the last 10 Planning Years. The last two data points show the Summer PRM UCAP values following FERC acceptance of MISO's seasonal capacity construct, while the prior data points are indicative of the PRM UCAP under the annual capacity construct.

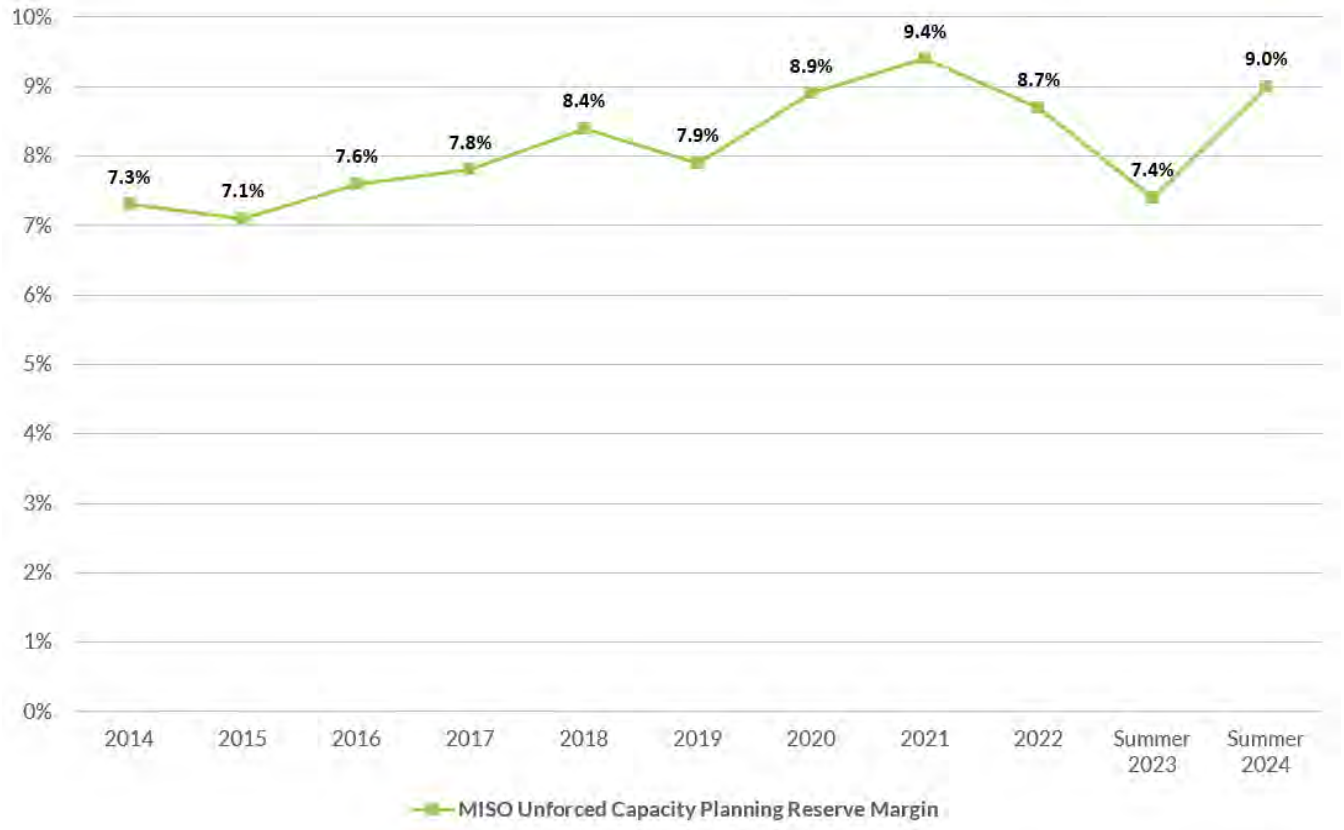


Figure 4-1: Comparison of PRM Targets Across 10 Years

5 Local Resource Zone Analysis – LRR Results

5.1 Planning Year 2024-2025 Local Resource Zone Analysis

MISO calculated the per-unit LRR of LRZ seasonal peak demand for Planning Year 2024-2025 on a seasonal basis (Table 5-1, Table 5-2, Table 5-3, & Table 5-4). The UCAP values in the seasonal LRR tables reflect the assumed seasonal UCAP within each LRZ, including Coordinating Owner External Resources and Border External Resources. The adjustments to UCAP values are the megawatt adjustments needed in each LRZ so that the seasonal LOLE criteria is met. The LRR is the summation of the zone's UCAP and adjustment to UCAP megawatts. The LRR is then divided by each LRZ's seasonal peak demand to determine the per-unit LRR UCAP. The Planning Year 2024-2025 per-unit LRR UCAP values will be multiplied by the updated seasonal peak demand forecasts submitted for the 2024-2025 PRA to determine each LRZ's LRR. Zonal peak demand timestamps for all 30 weather years modeled in SERVM are shown in Table 5-5. These peak demand timestamps are the result of the SERVM load training process and are not necessarily the actual peaks for each year.

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
PY 2024-2025 Local Reliability Requirements – Summer 2024											
Installed Capacity (ICAP) (MW)	22,031	14,680	12,032	9,635	7,942	17,184	25,178	11,749	24,009	5,748	[A]
Unforced Capacity (UCAP) (MW)	20,970	13,866	11,487	8,745	7,361	15,348	23,578	10,915	22,113	5,061	[B]
Adjustment to UCAP (MW)	380	590	1,503	3,245	3,044	5,209	980	692	2,502	2,093	[C]
LRR (UCAP) (MW)	21,351	14,456	12,990	11,990	10,405	20,557	24,558	11,607	24,615	7,153	[D]=[B]+[C]
Peak Demand (MW)	18,854	12,990	10,165	9,288	7,814	17,279	21,160	8,336	21,689	4,712	[E]
LRR UCAP per-unit of LRZ Peak Demand	**113.2%**	**111.3%**	**127.8%**	**129.1%**	**133.1%**	**119.0%**	**116.1%**	**139.2%**	**113.5%**	**151.8%**	[F]=[D]/[E]

Table 5-1: Planning Year 2024-2025 LRZ Local Reliability Requirements for Summer 2024

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
PY 2024-2025 Local Reliability Requirements – Fall 2024											
Installed Capacity (ICAP) (MW)	21,604	14,808	11,765	9,543	8,092	17,140	24,487	11,568	23,995	5,753	[A]
Unforced Capacity (UCAP) (MW)	20,167	13,723	11,151	8,300	7,428	15,491	22,832	10,923	21,477	5,081	[B]
Adjustment to UCAP (MW)	-847	-402	1,007	2,303	2,486	4,040	956	427	2,440	2,041	[C]
LRR (UCAP) (MW)	19,320	13,321	12,157	10,604	9,914	19,531	23,787	11,349	23,917	7,122	[D]=[B]+[C]
Peak Demand (MW)	15,645	11,113	9,037	8,014	6,880	15,537	18,142	7,585	20,095	4,272	[E]
LRR UCAP per-unit of LRZ Peak Demand	**123.5%**	**119.9%**	**134.5%**	**132.3%**	**144.1%**	**125.7%**	**131.1%**	**149.6%**	**119.0%**	**166.7%**	[F]=[D]/[E]

Table 5-2: Planning Year 2024-2025 LRZ Local Reliability Requirements for Fall 2024

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
PY 2024-2025 Local Reliability Requirements – Winter 2024-2025											
Installed Capacity (ICAP) (MW)	24,143	15,861	16,846	11,141	8,737	18,366	26,118	12,347	26,054	6,312	[A]
Unforced Capacity (UCAP) (MW)	21,941	13,894	15,443	7,142	6,199	14,464	23,949	11,108	23,558	5,504	[B]
Adjustment to UCAP (MW)	143	-500	1,432	3,053	2,936	4,899	-1,153	651	2,353	1,968	[C]
LRR (UCAP) (MW)	22,084	13,394	16,874	10,195	9,136	19,363	22,796	11,760	25,911	7,472	[D]=[B]+[C]
Peak Demand (MW)	15,312	9,830	8,413	7,622	7,110	15,779	14,186	7,539	19,513	4,009	[E]
LRR UCAP per-unit of LRZ Peak Demand	**144.2%**	**136.3%**	**200.6%**	**133.8%**	**128.5%**	**122.7%**	**160.7%**	**156.0%**	**132.8%**	**186.4%**	[F]=[D]/[E]

Table 5-3: Planning Year 2024-2025 LRZ Local Reliability Requirements for Winter 2024-2025

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
PY 2024-2025 Local Reliability Requirements – Spring 2025											
Installed Capacity (ICAP) (MW)	21,887	15,164	12,479	10,301	8,322	17,448	24,391	11,755	24,434	5,911	[A]
Unforced Capacity (UCAP) (MW)	20,576	14,079	11,568	8,579	7,082	15,812	22,221	10,549	22,516	5,269	[B]
Adjustment to UCAP (MW)	-1,500	-260	730	2,652	2,957	4,098	-920	292	2,491	2,077	[C]
LRR (UCAP) (MW)	19,076	13,819	12,298	11,231	10,040	19,909	21,301	10,841	25,007	7,346	[D]=[B]+[C]
Peak Demand (MW)	14,356	10,137	8,034	6,756	6,206	14,523	16,109	6,733	18,746	3,911	[E]
LRR UCAP per-unit of LRZ Peak Demand	**132.9%**	**136.3%**	**153.1%**	**166.2%**	**161.8%**	**137.1%**	**132.2%**	**161.0%**	**133.4%**	**187.8%**	[F]=[D]/[E]

Table 5-4: Planning Year 2024-2025 LRZ Local Reliability Requirements for Spring 2025

Weather Year Time of Peak Demand (ESTHE)	MISO	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS
1993	7/27/93 17:00	8/11/93 17:00	8/27/93 14:00	8/22/93 19:00	7/17/93 17:00	7/27/93 16:00	7/25/93 16:00	7/9/93 15:00	7/31/93 17:00	8/14/93 16:00	7/31/93 18:00
1994	7/6/94 15:00	6/14/94 17:00	6/15/94 17:00	7/19/94 17:00	7/5/94 17:00	7/19/94 18:00	1/19/94 6:00	6/18/94 17:00	6/29/94 18:00	8/14/94 17:00	7/5/94 17:00
1995	7/13/95 17:00	7/13/95 18:00	7/13/95 16:00	7/14/95 17:00	7/14/95 17:00	7/13/95 16:00	7/13/95 17:00	7/13/95 17:00	8/17/95 14:00	7/27/95 17:00	7/12/95 15:00
1996	6/29/96 17:00	8/6/96 17:00	6/29/96 17:00	7/18/96 17:00	7/18/96 18:00	7/18/96 17:00	7/19/96 17:00	8/7/96 15:00	7/20/96 15:00	2/5/96 7:00	7/3/96 18:00
1997	7/26/97 16:00	7/16/97 16:00	7/16/97 17:00	7/25/97 18:00	7/18/97 16:00	7/26/97 17:00	7/26/97 16:00	7/16/97 16:00	7/25/97 18:00	8/16/97 16:00	7/25/97 18:00
1998	7/20/98 16:00	7/13/98 16:00	6/25/98 18:00	7/20/98 18:00	7/20/98 18:00	7/19/98 16:00	7/19/98 17:00	6/25/98 18:00	7/6/98 17:00	8/28/98 18:00	8/27/98 15:00
1999	7/30/99 14:00	7/25/99 15:00	7/13/95 16:00	7/30/99 18:00	7/18/99 22:00	7/30/99 17:00	7/26/97 16:00	7/30/99 14:00	7/25/99 17:00	8/14/99 18:00	8/20/99 18:00
2000	8/31/00 16:00	6/8/00 19:00	9/1/00 17:00	8/31/00 16:00	9/1/00 15:00	8/17/00 16:00	9/1/00 15:00	9/1/00 14:00	7/19/00 17:00	8/30/00 16:00	8/30/00 17:00
2001	8/8/01 16:00	8/7/01 16:00	8/9/01 16:00	7/31/01 16:00	7/23/01 17:00	7/23/01 17:00	8/7/01 17:00	8/8/01 16:00	7/11/01 16:00	7/10/01 16:00	7/20/01 17:00
2002	7/3/02 16:00	7/6/02 18:00	8/1/02 15:00	7/20/02 18:00	7/5/02 17:00	8/1/02 16:00	8/3/02 16:00	7/3/02 16:00	7/9/02 17:00	8/2/02 19:00	10/4/02 15:00
2003	8/21/03 16:00	8/24/03 17:00	8/21/03 16:00	7/26/03 18:00	8/21/03 16:00	8/21/03 18:00	8/27/03 17:00	8/21/03 17:00	7/18/03 14:00	8/10/03 16:00	7/17/03 17:00
2004	7/22/04 16:00	6/7/04 17:00	7/22/04 16:00	7/20/04 17:00	7/13/04 17:00	7/13/04 16:00	1/31/04 9:00	7/22/04 16:00	7/14/04 17:00	7/24/04 17:00	7/25/04 15:00
2005	7/24/05 17:00	7/17/05 17:00	7/24/05 16:00	7/25/05 17:00	7/24/05 16:00	7/24/05 18:00	7/25/05 17:00	7/24/05 18:00	8/21/05 18:00	7/25/05 16:00	8/21/05 15:00
2006	7/31/06 17:00	7/31/06 17:00	8/1/06 17:00	7/19/06 18:00	7/31/06 18:00	7/31/06 16:00	7/31/06 16:00	7/31/06 16:00	7/31/93 17:00	8/15/06 18:00	7/16/06 15:00
2007	8/1/07 17:00	7/26/07 15:00	8/2/07 15:00	7/17/07 17:00	8/15/07 18:00	8/15/07 18:00	8/29/07 17:00	7/31/07 18:00	8/17/95 14:00	8/14/07 15:00	8/14/07 15:00
2008	7/16/08 17:00	7/11/08 18:00	7/17/08 17:00	8/3/08 17:00	7/20/08 17:00	7/20/08 16:00	8/23/08 16:00	8/24/08 12:00	8/17/95 14:00	7/20/08 17:00	7/27/08 16:00
2009	6/25/09 16:00	6/22/09 19:00	7/28/09 16:00	7/24/09 18:00	8/9/09 16:00	8/9/09 16:00	1/16/09 8:00	6/25/09 16:00	6/22/09 16:00	7/2/09 16:00	7/2/09 18:00

Weather Year Time of Peak Demand (ESTHE)	MISO	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS
2010	8/10/10 17:00	8/8/10 18:00	8/20/10 14:00	7/17/10 19:00	7/15/10 15:00	8/3/10 16:00	8/2/91 18:00	9/1/10 17:00	8/17/95 14:00	8/1/10 17:00	8/2/10 17:00
2011	7/20/11 18:00	6/7/11 19:00	7/13/95 16:00	7/20/11 16:00	9/1/11 16:00	8/31/11 16:00	7/26/97 16:00	7/20/11 19:00	7/31/93 17:00	7/2/11 17:00	7/10/11 18:00
2012	7/6/12 17:00	7/6/12 18:00	7/13/95 16:00	7/7/12 16:00	7/7/12 17:00	7/25/12 18:00	7/26/97 16:00	7/6/12 17:00	7/30/12 17:00	6/26/12 16:00	7/3/12 15:00
2013	7/19/13 16:00	7/18/13 19:00	8/27/13 16:00	8/30/13 16:00	9/11/13 16:00	8/31/13 17:00	8/31/13 15:00	7/19/13 14:00	6/27/13 18:00	8/7/13 16:00	8/8/13 17:00
2014	7/22/14 16:00	7/22/14 17:00	7/22/14 16:00	7/22/14 16:00	9/5/14 16:00	7/26/14 15:00	2/7/14 9:00	7/22/14 17:00	7/27/14 17:00	8/23/14 16:00	7/26/14 17:00
2015	7/29/15 16:00	8/14/15 15:00	8/14/15 17:00	7/13/15 15:00	9/3/15 16:00	7/13/15 16:00	7/18/15 17:00	8/2/15 16:00	8/7/15 18:00	8/10/15 16:00	7/30/15 16:00
2016	7/20/16 15:00	7/21/16 17:00	8/10/16 17:00	7/22/16 16:00	9/22/16 16:00	7/23/16 17:00	6/11/16 14:00	8/10/16 14:00	7/20/16 13:00	9/1/16 16:00	7/20/16 15:00
2017	7/20/17 16:00	7/6/17 17:00	6/12/17 14:00	7/21/17 17:00	9/26/17 15:00	7/12/17 15:00	9/26/17 16:00	6/12/17 14:00	7/21/17 15:00	8/19/17 15:00	7/20/17 15:00
2018	6/29/18 15:00	6/29/18 15:00	6/29/18 15:00	5/28/18 14:00	9/5/18 15:00	8/6/18 16:00	9/5/18 16:00	9/5/18 15:00	1/17/18 6:00	1/17/18 6:00	9/19/18 16:00
2019	7/19/19 14:00	7/19/19 18:00	7/19/19 16:00	7/19/19 14:00	9/12/19 16:00	10/1/19 15:00	9/13/19 16:00	7/19/19 13:00	8/13/19 14:00	10/4/19 15:00	10/2/19 16:00
2020	7/9/20 15:00	7/2/20 17:00	8/27/20 14:00	7/8/20 14:00	7/8/20 15:00	7/11/20 15:00	8/25/20 15:00	7/9/20 15:00	7/12/20 15:00	7/11/20 15:00	9/4/20 16:00
2021	8/24/21 15:00	7/27/21 16:00	8/10/21 15:00	7/28/21 16:00	8/27/21 15:00	8/25/21 16:00	8/24/21 16:00	8/24/21 15:00	8/10/21 14:00	8/23/21 16:00	7/29/21 14:00
2022	7/19/22 17:00	7/19/22 18:00	6/15/22 16:00	7/23/22 16:00	8/13/22 18:00	7/23/22 15:00	7/11/22 17:00	6/21/22 17:00	7/8/22 16:00	9/21/22 17:00	8/15/22 17:00

Table 5-5: Modeled Peak Demand Days/Hours by Local Resource Zone

6 Appendix A: Comparison of Planning Year 2023-2024 to Planning Year 2024-2025

Multiple study sensitivity analyses were performed to compute changes in the PRM target on a UCAP basis for each season, from Planning Year 2023-2024 to Planning Year 2024-2025. These sensitivities included one-off incremental changes of input parameters to quantify how each change affected the PRM result independently. Note the impact of the incremental PRM changes from Planning Year 2023-2024 to Planning Year 2024-2025 in the waterfall charts below (Figure A-1, Figure A-2, Figure A-3, & Figure A-4). The following subsections provide more details around each of the sensitivities.

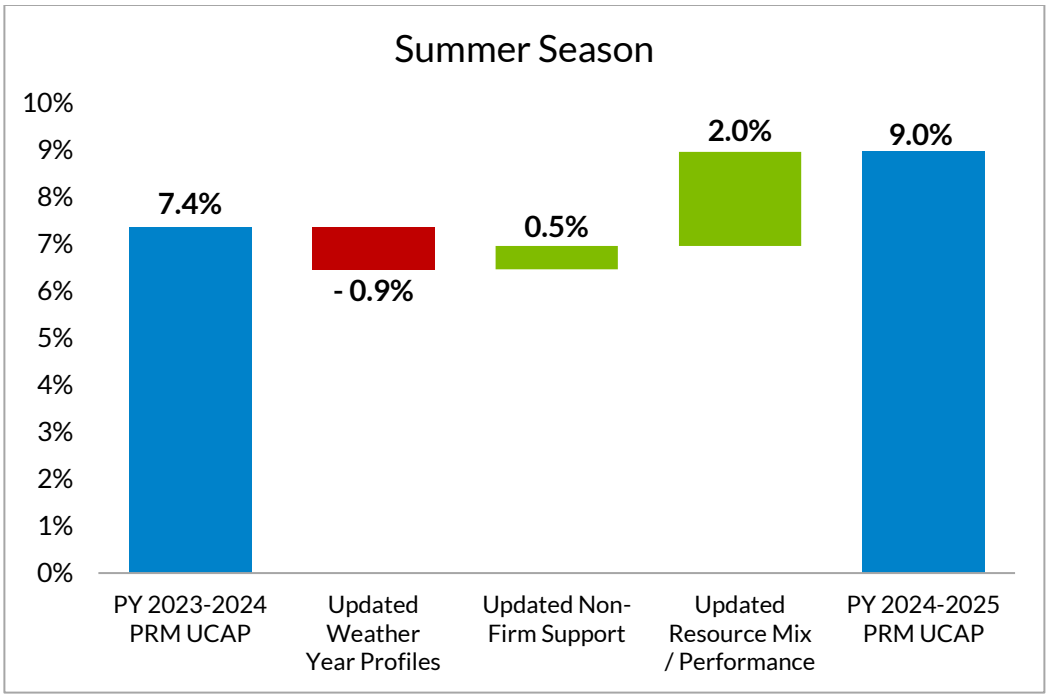


Figure A-1: Waterfall Chart of Summer PRM UCAP from PY 2023-2024 to PY 2024-2025

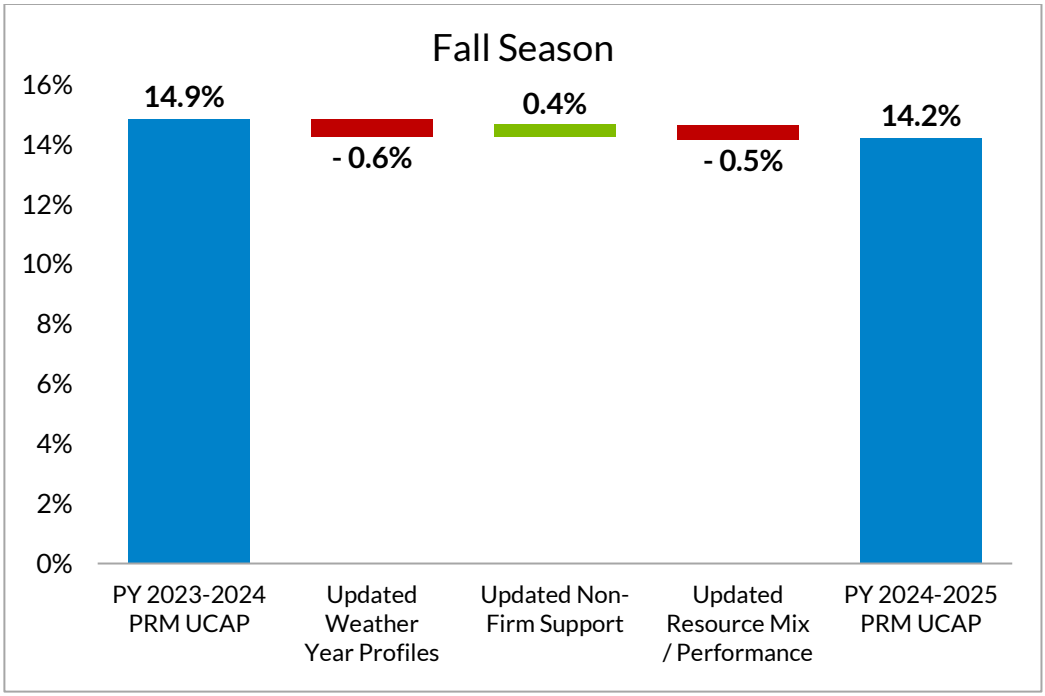


Figure A-2: Waterfall Chart of Fall PRM UCAP from PY 2023-2024 to PY 2024-2025

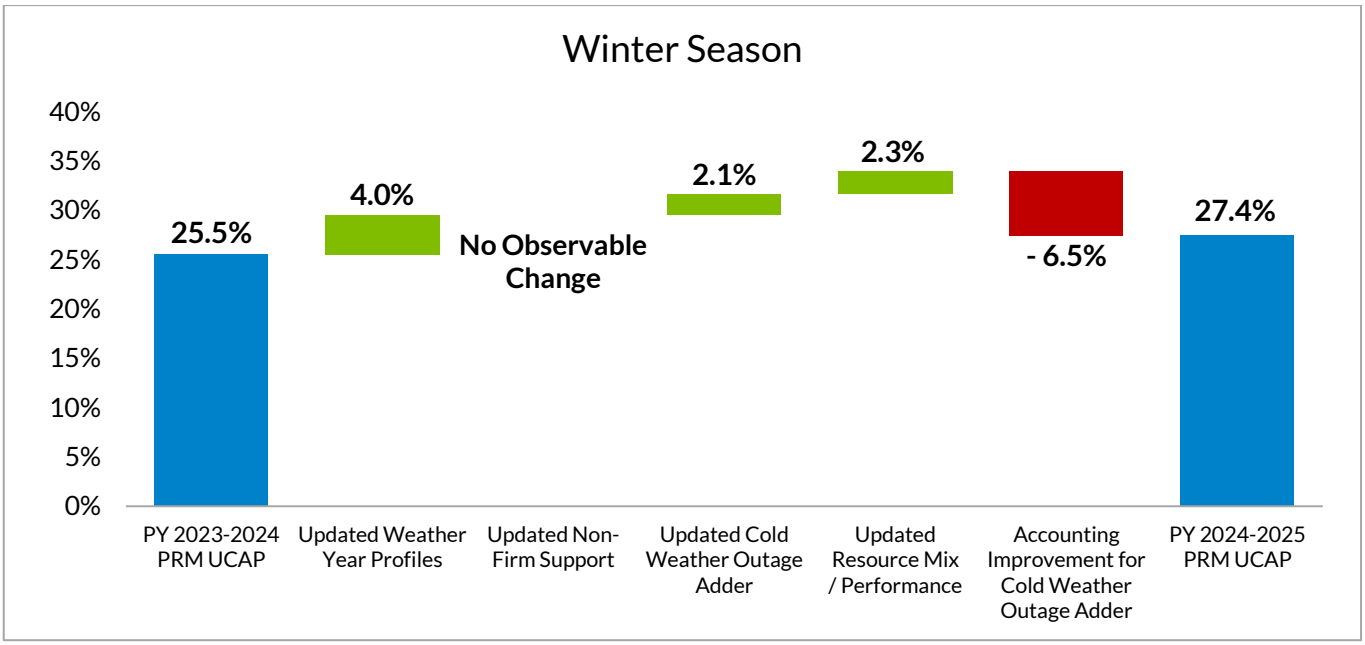


Figure A-3: Waterfall Chart of Winter PRM UCAP from PY 2023-2024 to PY 2024-2025

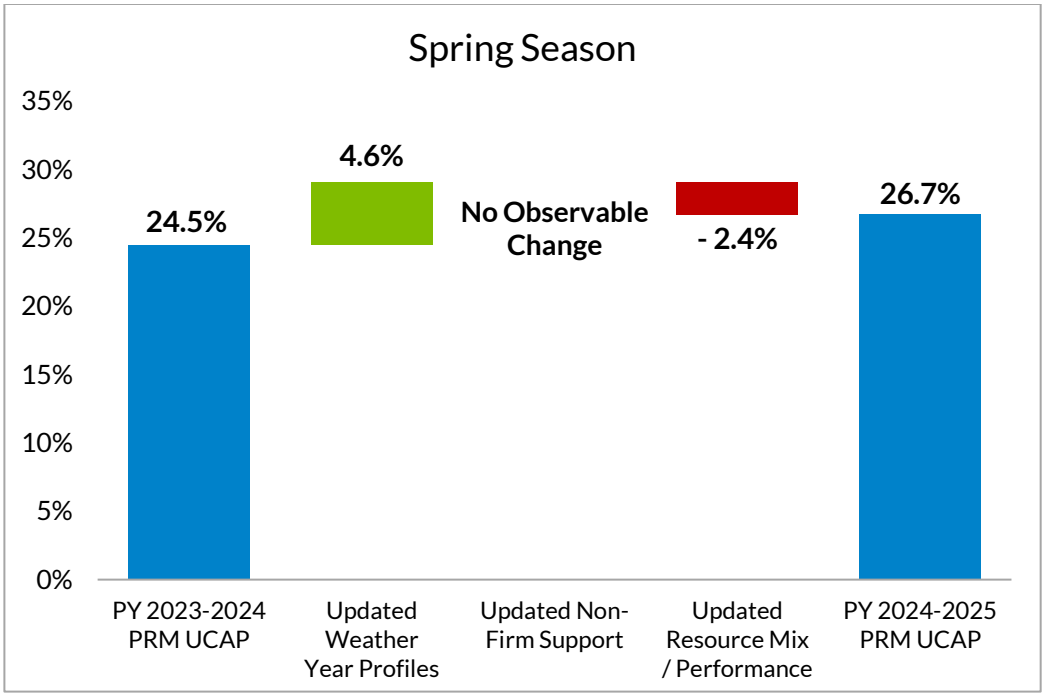


Figure A-4: Waterfall Chart of Spring PRM UCAP from PY 2023-2024 to PY 2024-2025

6.1 Waterfall Chart Details

6.1.1 Updated Weather Year Profiles

With the annual refresh to the LOLE model, the oldest weather year is dropped off and a new weather year is added. Previously, only load shapes were tied to the weather years. Now, with the addition to the model of hourly profiles for renewables and the cold weather outage adder, it is no longer possible to isolate just the updated load profiles as stakeholders may be used to seeing in prior reports.

6.1.2 Updated Non-Firm Support

The probabilistic distribution of seasonal non-firm support is not tied to any specific weather years and is the next input dataset to be replaced in the LOLE model.

6.1.3 Updated Resource Mix / Performance

Changes in resource capability from Planning Year 2023-2024 are primarily driven by a methodology change in the Planning Resource Auction (PRA) to request from generation owners seasonally corrected Generation Verification Test Capacity (GVTC). Other drivers include updated seasonal forced outage rates, updated annualized planned maintenance outage rates, new units, retirements, suspensions, and changes in the resource mix. There was also a modeling improvement to make battery storage use-limited in the model that would also be a driver for change.

6.1.4 Updated Cold Weather Outage Adder (Winter only)

The isolated impact on the system-wide PRM requirement of modeling outage adder during extreme cold temperatures was found to be 6,710 MW. When compared to the cold weather outage adder from the prior year study, this represents an approximately 2.2 GW impact increase year-over-year.

6.1.5 Accounting Improvement for Cold Weather Outage Adder (Winter only)

The modeling of additional forced outages in the Winter season due to the adder induces a more elevated volume of forced outages in the model beyond the average Winter forced outage rates, but this was previously not reflected in the PRM and LRR accounting. ELCC-type analysis was performed to quantify the system-wide impact of modeling the cold weather outage adder profiles. Including these additional Winter forced outages in the numerator of the requirement calculations as a reduction in total Unforced Capacity lowers Winter requirements.

7 Appendix B: Increased Winter Thermal Capability Sensitivity

As requested by stakeholders at the LOLEWG, MISO performed a sensitivity for the Winter season to better understand the impact of including increased Winter capabilities of certain thermal resources to the Winter Planning Reserve Margin Requirement. For this sensitivity, MISO utilized generation owners' seasonal GVTC values for the Planning Year 2023-2024 Planning Resource Auction and scaled the thermal Winter capabilities by, approximately, an additional 20% to see how the adjustment to capacity in the model changed to maintain the same LOLE criteria. This sensitivity demonstrated that there are diminishing returns for the ability to reduce risk in the model when there is a saturated increase in resource capability. Increased capability across the same set of resources may not translate to increased availability, as non-risk hours that already had excess generation may see no benefit whereas risk hours may be exacerbated, or more risk hours may emerge, from an elevated volume of outages when forced and planned maintenance outage rates are applied to a higher thermal capability.

8 Appendix C: Capacity Import Limit Tier 1 & 2 Source Subsystem Definitions

MISO Local Resource Zone 1

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
XEL / 600	ITCM / 627	WEC / 295
MP / 608	ALTE / 694	MIUP / 296
SMMPA / 613	WPS / 696	AMMO / 356
GRE / 615	MGE / 697	AMIL / 357
OTP / 620		MPW / 633
MDU / 661		MEC / 635
BEPC-MISO / 663		
DPC / 680		

MISO Local Resource Zone 2

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #	
WEC / 295	METC / 218	NIPS / 217	OTP / 620
MIUP / 296	XEL / 600	ITCT / 219	MPW / 633
ALTE / 694	MP / 608	AMMO / 356	MEC / 635
WPS / 696	ITCM / 627	AMIL / 357	
MGE / 697	DPC / 680	SMMPA / 613	
UPPC / 698		GRE / 615	

MISO Local Resource Zone 3

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #	
ITCM / 627	AMMO / 356	DEI / 208	MP / 608
MPW / 633	AMIL / 357	NIPS / 217	GRE / 615
MEC / 635	XEL / 600	WEC / 295	OTP / 620
	SMMPA / 613	CWLP / 360	WPS / 696
	DPC / 680	SIPC/ 361	MGE / 697
	ALTE / 694	GLHB / 362	

MISO Local Resource Zone 4

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #	
AMIL / 357	DEI / 208	HE / 207	SMMPA / 613
CWLP / 360	NIPS / 217	SIGE / 210	MPW / 633
SIPC / 361	BREC / 314	IPL / 216	DPC / 680
GLHB / 362	AMMO / 356	METC / 218	ALTE / 694
GLH / 373	ITCM / 627	HMPL / 315	
	MEC / 635	XEL / 600	

MISO Local Resource Zone 5

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #	
CWLD / 333	AMIL / 357	DEI / 208	SMMPA / 613
AMMO / 356	GLHB / 362	NIPS / 217	MPW / 633
	ITCM / 627	CWLP / 360	DPC / 680
	MEC / 635	SIPC / 361	ALTE / 694
		XEL / 600	

MISO Local Resource Zone 6

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
HE / 207	METC / 218	ITCT / 219
DEI / 208	AMIL / 357	MIUP / 296
SIGE / 210	SIPC / 361	AMMO / 356
IPL / 216		CWLP / 360
NIPS / 217		GLHB / 362
BREC / 314		ITCM / 627
HMPL / 315		MEC / 635

MISO Local Resource Zone 7

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
METC / 218	NIPS / 217	DEI / 208
ITCT / 219	MIUP / 296	WEC / 295
		AMIL / 356
		WPS / 696
		UPPC / 698

MISO Local Resource Zone 8

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
EES-EAI / 327	EES-EMI / 326	LAGN / 332
	EES / 351	Cooperative Energy / 349
		CLEC / 502
		LAFA / 503

MISO Local Resource Zone 9

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
LAGN / 332	EES-EMI / 326	Cooperative Energy / 349
EES / 351	EES-EAI / 327	
CLEC / 502		
LAFA / 503		
LEPA / 504		

MISO Local Resource Zone 10

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
EES-EMI / 326	EES-EAI / 327	LAGN / 332
Cooperative Energy / 349	EES / 351	CLEC / 502
		LAFA / 503

9 Appendix D: Compliance Conformance Table

Requirements under: Standard BAL-502-RF-03	Response
R1 The Planning Coordinator shall perform and document a Resource Adequacy analysis annually. The Resource Adequacy analysis shall:	The Planning Year 2024-2025 LOLE Study Report is the annual Resource Adequacy Analysis for the peak season of June 2024 through May 2025 and beyond. Analysis of Planning Year 2024-2025 is in Sections 4.1 and 5.1. Analysis of Future Years 2025-2034 are included in Appendix F as an addendum to the study report.
R1.1 Calculate a planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year[1] analyzed (per R1.2) being equal to 0.1. (This is comparable to a "one day in 10 years" criterion).	Section 3.5 of this report outlines the utilization of LOLE in the reserve margin determination. "These metrics were derived through probabilistic modeling of the system, first solving to the industry standard annual LOLE risk target of 1 day in 10 years, or 0.1 day per year, and then solving to the minimum seasonal LOLE criteria of 0.01 LOLE for seasons demonstrating minimal risk."
R1.1.1 The utilization of Direct Control Load Management or curtailment of Interruptible Demand shall not contribute to the loss of Load probability.	Section 3.3 of this report. "Direct Control Load Management and Interruptible Demand types of demand response were explicitly included in the LOLE model as resources. Demand response is dispatched in the LOLE model to avoid load shed during simulation when all other available generation has been exhausted."
R1.1.2 The planning reserve margin developed from R1.1 shall be expressed as a percentage of the median forecast peak Net Internal Demand (planning reserve margin).	Section 4.1 of this report. "…the ratio of MISO capacity to forecasted MISO system peak demand yielded a planning ICAP reserve margin…"
R1.2 Be performed or verified separately for each of the following planning years.	Covered in the segmented R1.2 responses below.
R1.2.1 Perform an analysis for Year One.	In Sections 4.1 and 5.1, a full analysis was performed for Planning Year 2024-2025.
R1.2.2 Perform an analysis or verification at a minimum for one year in the 2 through 5-year period and at a minimum one year in the 6 though 10 year period.	Analysis of Planning Years 2027-2028 and 2029-2030 are included in Appendix F as an addendum to the study report.

Requirements under: Standard BAL-502-RF-03	Response
R1.2.2.1 If the analysis is verified, the verification must be supported by current or past studies for the same planning year.	Analysis was performed.
R1.3 Include the following subject matter and documentation of its use:	Covered in the segmented R1.3 responses below.
R1.3.1 Load forecast characteristics: • Median (50:50) forecast peak load • Load forecast uncertainty (reflects variability in the Load forecast due to weather and regional economic forecasts) • Load diversity • Seasonal Load variations • Daily demand modeling assumptions (firm, interruptible) • Contractual arrangements concerning curtailable/Interruptible Demand	Median forecasted load – In Section 3.3 of this report: "The sixth and final step of the load training process is to average the monthly peak loads of the predicted load shapes and adjust them to match each LRZ's monthly Zonal Coincident Peak Forecast provided by the Load Serving Entities for each of the study years." Load Forecast Uncertainty – A detailed explanation of the weather and economic uncertainties is given in Section 3.3. Load Diversity / Seasonal Load Variations — In Section 3.3 of this report: "MISO has adopted a six-step load training process in order to capture the weather uncertainty associated with the most recent 50/50 load forecasts submitted by the Load Serving Entities for the development of the 30 years of hourly zonal correlated load and weather shapes in the LOLE model. The third step of the process utilizes neural net software to establish functional relationships between the most recent five years of historical weather and load data." Demand Modeling Assumptions / Curtailable and Interruptible Demand — All Load Modifying Resources must first meet registration requirements through Module E of the MISO Tariff. As stated in Section 3.2.6: "Each demand response program was modeled individually with a monthly capability, limited by duration, and the number of times each program can be called upon for each season."

Requirements under: Standard BAL-502-RF-03	Response
R1.3.2 Resource characteristics: • Historic resource performance and any projected changes • Seasonal resource ratings • Modeling assumptions of firm capacity purchases from and sales to entities outside the Planning Coordinator area • Resource planned outage schedules, deratings, and retirements • Modeling assumptions of intermittent and energy limited resource such as wind and cogeneration • Criteria for including planned resource additions in the analysis	Section 3.2 details how historic performance data and seasonal ratings are gathered and includes discussion of future units and the modeling assumptions for intermittent capacity resources. A more detailed explanation of firm capacity purchases and sales is in Section 3.4.
R1.3.3 Transmission limitations that prevent the delivery of generation reserves	Annual MTEP deliverability analysis identifies transmission limitations preventing delivery of generation reserves. Additionally, Section 2 of this report details the transfer analysis to capture transmission constraints limiting capacity transfers.
R1.3.3.1 Criteria for including planned Transmission Facility additions in the analysis	Inclusion of the planned transmission addition assumptions is detailed in Section 2.2.3.
R1.3.4 Assistance from other interconnected systems including multi-area assessment considering Transmission limitations into the study area.	Section 3.4 provides the analysis on the treatment of external support assistance and limitations.

Requirements under: Standard BAL-502-RF-03	Response
R1.4 Consider the following resource availability characteristics and document how and why they were included in the analysis or why they were not included: • Availability and deliverability of fuel • Common mode outages that affect resource availability • Environmental or regulatory restrictions of resource availability • Any other demand (Load) response programs not included in R1.3.1 • Sensitivity to resource outage rates • Impacts of extreme weather/drought conditions that affect unit availability • Modeling assumptions for emergency operation procedures used to make reserves available • Market resources not committed to serving Load (uncommitted resources) within the Planning Coordinator area	Fuel availability, environmental restrictions, common mode outage, and extreme weather conditions are all part of the historical availability performance data that goes into the unit's EFORd statistic. The use of the EFORd values is covered in Section 3.2.1. The use of demand response programs is mentioned in Section 3.2.6. The effects of resource outage characteristics on the reserve margin are outlined in Section 3.5.2 by examining the difference between PRM ICAP and PRM UCAP values.
R1.5 Consider Transmission maintenance outage schedules and document how and why they were included in the Resource Adequacy analysis or why they were not included	Transmission maintenance schedules were not included in the analysis of the transmission system due to the limited availability of reliable long-term maintenance schedules and minimal impact to the results of the analysis. However, Section 2 treats worst-case theoretical outages by performing First Contingency Total Transfer Capability (FCTTC) analysis for each LRZ, by modeling NERC Category P0 (system intact) and Category P1 (N-1) contingencies.
R1.6 Document that capacity resources are appropriately accounted for in its Resource Adequacy analysis	MISO internal resources are among the quantities documented in the tables provided in Sections 4 and 5.
R1.7 Document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis	MISO load is among the quantities documented in the tables provided in Sections 4 and 5.
R2 The Planning Coordinator shall annually document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis.	In Sections 4 and 5, the peak load and estimated amount of resources for Planning Year 2024-2025 are shown. This includes the detail for each transmission constrained sub-area.
R2.1 This documentation covers each of the years in year one through ten.	Appendix F covers the future Planning Years.

Requirements under: Standard BAL-502-RF-03	Response
R2.2 This documentation includes the Planning Reserve margin calculated per requirement R1.1 for each of the three years in the analysis.	The prompt Planning Year seasonal PRM values are covered in Sections 4.1. The outyear Planning Years 4 (2027-2028) and 6 (2029-2030) are covered in Appendix F.
R2.3 The documentation as specified per requirement R2.1 and R2.2 shall be publicly posted no later than 30 calendar days prior to the beginning of Year One.	The final Planning Year 2024-2025 LOLE Study Report was posted publicly in December 2023, several months prior to the start of the applicable Planning Year.
R3 The Planning Coordinator shall identify any gaps between the needed amount of planning reserves defined in Requirement R1, Part 1.1 and the projected planning reserves documented in Requirement R2.	Sections 4 and 5 show the differences between the needed amount and the projected planning reserves for Planning Year 2024-2025. The needed amount of planning reserves for the outyear Planning Years 4 (2027-2028) and 6 (2029-2030) are covered in Appendix F.

10 Appendix E: Acronyms List Table

CEL	Capacity Export Limit
CIL	Capacity Import Limit
CPNode	Commercial Pricing Node
DF	Distribution Factor
EFORd	Equivalent Forced Outage Rate demand
ELCC	Effective Load Carrying Capability
ERZ	External Resource Zone
EUE	Expected Unserved Energy
FERC	Federal Energy Regulatory Commission
FCITC	First Contingency Incremental Transfer Capability
FCTTC	First Contingency Total Transfer Capability
GADS	Generator Availability Data System
GLT	Generation Limited Transfer
GVTC	Generation Verification Test Capacity
ICAP	Installed Capacity
LBA	Local Balancing Authority
LCR	Local Clearing Requirement
LFE	Load Forecast Error
LFU	Load Forecast Uncertainty
LOLE	Loss of Load Expectation
LOLEWG	Loss of Load Expectation Working Group
LRR	Local Reliability Requirement
LRZ	Local Resource Zones
LSE	Load Serving Entity
MARS	Multi-Area Reliability Simulation
MECT	Module E Capacity Tracking
MISO	Midcontinent Independent System Operator
MOD	Model on Demand
MTEP	MISO Transmission Expansion Plan
MW	Megawatt
MWh	Megawatt hours
NERC	North American Electric Reliability Corporation

PRA	Planning Resource Auction
PRM	Planning Reserve Margin
PRM ICAP	PRM Installed Capacity
PRM UCAP	PRM Unforced Capacity
PRMR	Planning Reserve Margin Requirement
PSS E	Power System Simulator for Engineering
RCF	Reciprocal Coordinating Flowgate
RDS	Redispatch
RPM	Reliability Pricing Model
SERVM	Strategic Energy & Risk Valuation Model
SPS	Special Protection Scheme
TARA	Transmission Adequacy and Reliability Assessment
UCAP	Unforced Capacity
XEFORd	Equivalent Forced Outage Rate demand with adjustment to exclude events outside management control
ZIA	Zonal Import Ability
ZEA	Zonal Export Ability

11 Appendix F: Outyear PRM Results

Beyond the prompt Planning Year 2024-2025, LOLE analyses were performed for the four-year-out Planning Year of 2027-2028, and the six-year-out Planning Year of 2029-2030. Tables 11-1 and 11-2 show the capacity and demand values that went into the MISO system seasonal Planning Reserve Margin for outyears four and six, respectively. Tables 11-3, 11-4, 10-5, and 11-6 show the seasonal outyear PRM projections ten years out based on future capacity and demand assumptions.

11.1 Planning Year 2027-2028 MISO Planning Reserve Margin Results

For Planning Year 2027-2028, the ratio of MISO capacity to forecasted MISO system peak demand yielded a Planning Reserve Margin ICAP of 18.9 percent and a Planning Reserve Margin UCAP of 9.6 percent for the Summer season. Numerous values and calculations went into determining the four-year-out MISO system seasonal PRM ICAP and PRM UCAP (Table 11-1).

MISO Planning Reserve Margin (PRM)	PY 2027-2028 Summer	PY 2027-2028 Fall	PY 2027-2028 Winter	PY 2027-2028 Spring	Formula Key
MISO System Peak Demand (MW)	126,218	113,712	105,726	100,853	[A]
Installed Capacity (ICAP) (MW)	158,145	157,720	170,335	164,536	[B]
Unforced Capacity (UCAP) (MW)	146,508	144,619	147,165	150,185	[C]
Firm External Support ICAP (MW)	3,217	2,865	3,771	3,247	[D]
Firm External Support UCAP (MW)	3,052	2,758	3,613	3,105	[E]
Adjustment to ICAP (MW)	(11,250)	(15,600)	(16,750)	(19,400)	[F]
Adjustment to UCAP (MW)	(11,250)	(15,600)	(16,750)	(19,400)	[G]
ICAP PRM Requirement (PRMR) (MW)	150,112	144,984	157,356	148,383	[H] = [B]+[D]+[F]
UCAP PRM Requirement (PRMR) (MW)	138,309	131,777	134,028	133,890	[I] = [C]+[E]+[G]
MISO PRM ICAP	**18.9%**	**27.5%**	**48.8%**	**47.1%**	[J]=[H]-[A]/[A]
MISO PRM UCAP	**9.6%**	**15.9%**	**26.8%**	**32.8%**	[K]=[I]-[A]/[A]

Table 11-1: Planning Year 2027-2028 MISO System Planning Reserve Margins

11.2 Planning Year 2029-2030 MISO Planning Reserve Margin Results

For Planning Year 2029-2030, the ratio of MISO capacity to forecasted MISO system peak demand yielded a Planning Reserve Margin ICAP of 19.0 percent and a Planning Reserve Margin UCAP of 9.4 percent for the Summer season. Numerous values and calculations went into determining the six-year-out MISO system seasonal PRM ICAP and PRM UCAP (Table 11-2).

MISO Planning Reserve Margin (PRM)	**PY 2029-2030** Summer	**PY 2029-2030** Fall	**PY 2029-2030** Winter	**PY 2029-2030** Spring	**Formula Key**
MISO System Peak Demand (MW)	127,512	114,908	106,860	101,932	[A]
Installed Capacity (ICAP) (MW)	167,877	165,485	177,850	173,032	[B]
Unforced Capacity (UCAP) (MW)	155,733	151,779	153,853	157,958	[C]
Firm External Support ICAP (MW)	3,217	2,865	3,771	3,247	[D]
Firm External Support UCAP (MW)	3,052	2,758	3,613	3,105	[E]
Adjustment to ICAP (MW)	(19,330)	(21,830)	(22,500)	(25,000)	[F]
Adjustment to UCAP (MW)	(19,330)	(21,830)	(22,500)	(25,000)	[G]
ICAP PRM Requirement (PRMR) (MW)	151,764	146,520	159,121	151,279	[H] = [B]+[D]+[F]
UCAP PRM Requirement (PRMR) (MW)	139,454	132,707	134,967	136,063	[I] = [C]+[E]+[G]
MISO PRM ICAP	**19.0%**	**27.5%**	**48.9%**	**48.4%**	[J]=[H]-[A]/[A]
MISO PRM UCAP	**9.4%**	**15.5%**	**26.3%**	**33.5%**	[K]=[I]-[A]/[A]

Table 11-2: Planning Year 2029-2030 MISO System Planning Reserve Margins

11.3 MISO Planning Reserve Margin Outyear Projections

Tables 11-3, 11-4, 11-5, and 11-6 show the outyear seasonal PRM projections. Years one, four, and six were probabilistically modeled. PRM projections in years two, three, and five are the result of interpolation of the years studied and years seven through ten are the resulting extrapolations of the outyear analyses.

Metric	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
PRM ICAP	17.7%	18.1%	18.5%	18.9%	19.0%	19.0%	19.3%	19.5%	19.8%	20.1%
PRM UCAP	9.0%	9.2%	9.4%	9.6%	9.5%	9.4%	9.4%	9.5%	9.6%	9.7%
Demand (GW)	124.7	125.2	125.7	126.2	126.9	127.5	128.1	128.6	129.2	129.8
ICAP (GW)	150.2	152.8	155.5	158.1	163.0	167.9	171.4	175.0	178.5	182.0

Table 11-3: MISO Summer Planning Reserve Margin Outyear Projections

Metric	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
PRM ICAP	25.2%	25.9%	26.7%	27.5%	27.5%	27.5%	28.0%	28.4%	28.9%	29.4%
PRM UCAP	14.2%	14.8%	15.3%	15.9%	15.7%	15.5%	15.7%	16.0%	16.3%	16.5%
Demand (GW)	112.2	112.7	113.2	113.7	114.3	114.9	115.4	116.0	116.5	117.0
ICAP (GW)	148.8	151.7	154.7	157.7	161.6	165.5	168.8	172.2	175.5	178.9

Table 11-4: MISO Fall Planning Reserve Margin Outyear Projections

Metric	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
PRM ICAP	49.4%	49.2%	49.0%	48.8%	48.9%	48.9%	48.8%	48.7%	48.6%	48.5%
PRM UCAP	27.4%	27.2%	27.0%	26.8%	26.5%	26.3%	26.1%	25.8%	25.6%	25.4%
Demand (GW)	104.3	104.8	105.3	105.7	106.3	106.9	107.4	107.9	108.4	108.9
ICAP (GW)	165.9	167.4	168.9	170.3	174.1	177.8	180.2	182.6	185.0	187.4

Table 11-5: MISO Winter Planning Reserve Margin Outyear Projections

Metric	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
PRM ICAP	40.8%	42.9%	45.0%	47.1%	47.8%	48.4%	49.9%	51.5%	53.0%	54.5%
PRM UCAP	26.7%	28.7%	30.7%	32.8%	33.1%	33.5%	34.8%	36.2%	37.5%	38.9%
Demand (GW)	99.5	99.9	100.4	100.9	101.4	101.9	102.4	102.9	103.4	103.9
ICAP (GW)	152.1	156.2	160.4	164.5	168.8	173.0	177.2	181.4	185.6	189.8

Table 11-6: MISO Spring Planning Reserve Margin Outyear Projections

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

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

Exhibit 83
MISO 2025-26 LOLE Study Report



Planning Year 2025-2026 Loss of Load Expectation Study Report

The Planning Year 2025-2026 Loss of Load Expectation (LOLE) Study Report details the various inputs, assumptions, and methodologies utilized in both the probabilistic and the power flow analyses to establish the seasonal Planning Reserve Margin (PRM), Local Reliability Requirement (LRR), and Capacity Import/Export Limit (CIL/CEL) values.

Highlights

- Summer, Winter, and Spring Planning Reserve Margin (PRM) decreased from Planning Year 2024-2025, while the Fall PRM increased slightly.

- In the Planning Year 2025-2026 study, significant year-over-year differences in wind and solar Effective Load Carrying Capability (ELCC) were observed for the Fall, Winter, and Spring seasons.

- An enhanced load development process and improved outage rates were the primary factors for the changes in the Planning Year 2025-2026 results. Additionally, shifting risk hours and ongoing changes to the generation fleet impacted this year's results.

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Contents

Contents 2
Executive Summary 4
1 MISO System Planning Reserve Margin 6
1.1 LOLE Study Process Overview 6
1.1.1 Study Improvements 7
1.2 Planning Year 2025-2026 MISO Planning Reserve Margin Results 9
1.2.1 Additional Risk Metric Statistics 9
1.3 Comparison of PRM Targets Across 10 Years 10
1.4 Comparison of Planning Year 2024-2025 to Planning Year 2025-2026 11
1.4.1 Waterfall Chart Details 14
2 Local Resource Zone Analysis – LRR Results 15
2.1 Planning Year 2025-2026 Local Resource Zone Analysis 15
3 Loss of Load Expectation Analysis 20
3.1 LOLE Modeling Input Data and Assumptions 20
3.1.1 Resource Inclusion 20
3.1.2 Effective Load Carrying Capability (ELCC) 20
3.2 MISO Generation 22
3.2.1 Thermal Units 22
3.2.2 Behind-the-Meter Generation 23
3.2.3 Attachment Y 23
3.2.4 Future Generation 23
3.2.5 Intermittent Resources 24
3.2.6 Demand Response 24
3.3 MISO Capacity 24
3.4 MISO Load Data 27
3.4.1 Economic Load Uncertainty 32
3.5 External System 32
3.6 Loss of Load Expectation Analysis and Metric Calculations 33
3.6.1 Seasonal LOLE Distribution 34
3.6.2 MISO-Wide LOLE Analysis and PRM Calculation 34

3.6.3 LRZ LOLE Analysis and Local Reliability Requirement Calculation 35
4 Transfer Analysis 36
4.1 Calculation Methodology and Process Description 36
4.1.1 Generation Pools 36
4.1.2 Redispatch 36
4.1.3 Sensitivity 37
4.1.4 Generation Limited Transfer for CIL/CEL and ZIA/ZEA 38
4.1.5 Voltage Limited Transfer for CIL/CEL and ZIA/ZEA 38
4.2 Powerflow Models and Assumptions 39
4.2.1 Tools Used 39
4.2.2 Inputs Required 39
4.2.3 Powerflow Modeling 39
4.2.4 General Assumptions 40
4.3 Results for CIL/CEL and ZIA/ZEA 41
Appendix A: Capacity Import Limit Tier 1 & 2 Source Subsystem Definitions 52
Appendix B: Compliance Conformance Table 56
Appendix C: Acronyms List Table 61
Appendix D: Outyear PRM Results 63
D.1 Planning Year 2028-2029 MISO Planning Reserve Margin Results 63
D.1.1 Additional Risk Metric Statistics 63
D.2 Planning Year 2030-2031 MISO Planning Reserve Margin Results 64
D.2.1 Additional Risk Metric Statistics 64
D.3 MISO Planning Reserve Margin Outyear Projections 65

Executive Summary

In preparation for the annual Planning Resource Auction (PRA), MISO conducts an annual Loss of Load Expectation (LOLE) Study to determine Resource Adequacy Requirements for the upcoming Planning Year. These requirements are identified on a seasonal basis for each Local Resource Zone within MISO.

Review processes played an integral role in this study. MISO would like to thank the Loss of Load Expectation Working Group (LOLEWG), the Resource Adequacy Subcommittee (RASC), and the Independent Market Monitor (IMM) for their assistance and input in this year's study.

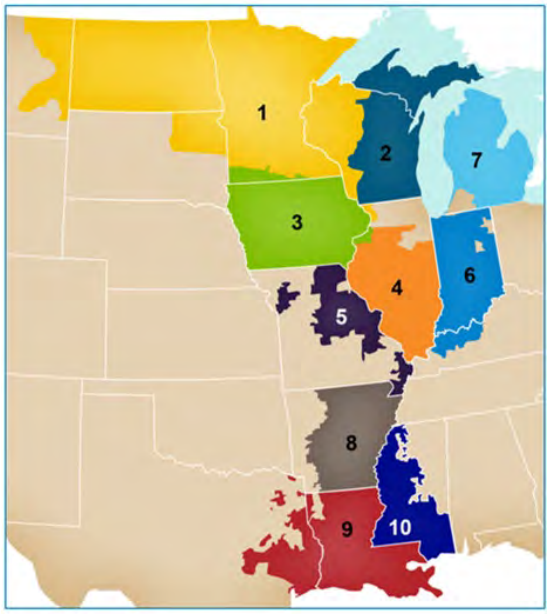
The seasonal Planning Reserve Margin (PRM) values determined through the Planning Year 2025-2026 LOLE study are provided in the table below.

Planning Year 2025-2026 Seasons	Summer 2025	Fall 2025	Winter 2025-2026	Spring 2026
MISO PRM UCAP	7.9%	14.9%	18.4%	25.3%

Table ES-1: Planning Reserve Margin Summary and Comparison

This study also determines zonal Local Reliability Requirements (LRRs). Additionally, initial values for zonal Capacity Import Limits (CIL) and Capacity Export Limits (CEL) for each season are also determined. These quantities are described in greater detail in Section 4.3.

MISO is divided into 10 Local Resource Zones (LRZs) as shown in the figure and table below.



Local Resource Zone	Local Balancing Authorities
1	DPC, GRE, MDU, MP, NSP OTP, SMP
2	ALTE, MGE, MIUP, UPPC, WEC, WPS
3	ALTW, MEC, MPW
4	AMIL, CWLP, GLH, SIPC
5	AMMO, CWLD
6	BREC, CIN, HE, HMPL, IPL, NIPS, SIGE
7	CONS, DECO
8	EAI
9	CLEC, EES, LAFA, LAGN, LEPA
10	EMBA, SME

Figure ES-2: Map of MISO Local Resource Zones
Table ES-2: Local Balancing Authority to Local Resource Zone Designations

Tables ES-3 through ES-6 below show results for each season.

PRA and LOLE Metrics	LRZ 1	LRZ 2	LRZ 3	LRZ 4	LRZ 5	LRZ 6	LRZ 7	LRZ 8	LRZ 9	LRZ 10
LRR UCAP per-unit of LRZ Peak Demand	1.195	1.135	1.318	1.280	1.301	1.262	1.138	1.350	1.136	1.447
Capacity Import Limit (CIL) (MW)	6,025	4,370	5,518	8,649	4,117	8,650	3,579	2,522	4,872	4,474
Capacity Export Limit (CEL) (MW)	3,991	4,614	4,655	4,460	3,939	6,881	5,716	6,345	3,775	2,097

Table ES-3: Initial Planning Resource Auction Deliverables — Summer 2025

PRA and LOLE Metrics	LRZ 1	LRZ 2	LRZ 3	LRZ 4	LRZ 5	LRZ 6	LRZ 7	LRZ 8	LRZ 9	LRZ 10
LRR UCAP per-unit of LRZ Peak Demand	1.288	1.222	1.537	1.320	1.365	1.312	1.255	1.469	1.198	1.557
Capacity Import Limit (CIL) (MW)	5,690	6,537	7,766	7,908	4,679	8,970	5,125	5,870	5,242	4,508
Capacity Export Limit (CEL) (MW)	6,165	4,259	5,862	4,174	5,816	5,173	5,158	4,024	3,672	3,164

Table ES-4: Initial Planning Resource Auction Deliverables — Fall 2025

PRA and LOLE Metrics	LRZ 1	LRZ 2	LRZ 3	LRZ 4	LRZ 5	LRZ 6	LRZ 7	LRZ 8	LRZ 9	LRZ 10
LRR UCAP per-unit of LRZ Peak Demand	1.267	1.353	1.632	1.186	1.254	1.247	1.447	1.566	1.297	1.628
Capacity Import Limit (CIL) (MW)	5,575	6,435	5,853	7,353	4,922	7,936	4,762	3,534	4,995	3,458
Capacity Export Limit (CEL) (MW)	3,591	4,793	7,412	4,635	4,814	1,665	5,712	3,681	3,041	2,028

Table ES-5: Initial Planning Resource Auction Deliverables — Winter 2025-2026

PRA and LOLE Metrics	LRZ 1	LRZ 2	LRZ 3	LRZ 4	LRZ 5	LRZ 6	LRZ 7	LRZ 8	LRZ 9	LRZ 10
LRR UCAP per-unit of LRZ Peak Demand	1.283	1.331	1.588	1.495	1.459	1.388	1.319	1.587	1.292	1.788
Capacity Import Limit (CIL) (MW)	6,398	6,439	7,784	8,272	4,453	9,491	5,166	6,250	5,370	4,365
Capacity Export Limit (CEL) (MW)	5,283	6,119	5,981	4,981	5,797	6,391	5,499	3,559	3,631	3,072

Table ES-6: Initial Planning Resource Auction Deliverables — Spring 2026

1 MISO System Planning Reserve Margin

1.1 LOLE Study Process Overview

In compliance with Module E-1 of the Tariff, MISO performed its annual LOLE study to determine, for each season of Planning Year 2025-2026, the system Planning Reserve Margin Unforced Capacity (PRM UCAP) and the Local Reliability Requirement (LRR) for each Local Resource Zone.

In addition to the LOLE analysis, MISO performed seasonal transfer analyses to determine seasonal Zonal Import Ability (ZIA), Zonal Export Ability (ZEA), Capacity Import Limits (CIL), and Capacity Export Limits (CEL). ZIA and controllable exports are used in conjunction with the Local Reliability Requirement (LRR) values to establish the seasonal Local Clearing Requirement (LCR) values in the Planning Resource Auction (PRA). Seasonal CIL and CEL values determine the maximum amount of capacity that can be imported or exported respectively to or from a zone. These variables are covered in Section 4 of this report.

The PY 2025-2026 per-unit seasonal LRR UCAP multiplied by the updated LRZ seasonal Peak Demand forecasts submitted for the 2025-2026 PRA determines each LRZ's seasonal LRR. Once the seasonal LRR is determined, the ZIA values and controllable exports are subtracted from the seasonal LRR to determine each LRZ's seasonal Local Clearing Requirement (LCR) consistent with Section 68A.6 of Module E-1[1]. An example LCR calculation pursuant to Section 68A.6 of the current effective Module E-1 shows how these values are reached (Table 1-1).

Local Resource Zone (LRZ) EXAMPLE	Example LRZ	Formula Key
Installed Capacity (ICAP)	17,442	[A]
Unforced Capacity (UCAP)	16,326	[B]
Adjustment to UCAP (1d in 10yr)	50	[C]
Local Reliability Requirement (LRR) (UCAP)	16,376	[D]=[B]+[C]
LRZ Peak Demand	14,270	[E]
LRR UCAP per-unit of LRZ Peak Demand	114.8%	[F]=[D]/[E]
Zonal Import Ability (ZIA)	3,469	[G]
Zonal Export Ability (ZEA)	2,317	[H]
Local Clearing Requirement (LCR) EXAMPLE	**Example LRZ**	**Formula Key**
Controllable Exports (UCAP)	150	[J]
Local Reliability Requirement (LRR) (UCAP)	16,376	[K]=[F]*[E]
Local Clearing Requirement (LCR)	12,757	[L]=[K]-[G]-[J]

Table 1-1: Example Local Clearing Requirement Calculation

The actual effective Planning Reserve Margin Requirement (PRMR) for each season of the 2025-2026 Planning Resource Auction will be determined after the updated LRZ Seasonal Peak Demand forecasts are submitted by November 1, 2024. The ZIA, ZEA, CIL, and CEL values are subject to updates in March 2025 based on changes to

[1] https://www.misoenergy.org/legal/tariff
Effective Date: September 1, 2022

exports of MISO resources to non-MISO load, changes to pseudo-tied commitments, and updates to facility ratings following the completion of the LOLE study.

Finally, the Simultaneous Feasibility Test (SFT) is performed as part of the PRA where the deliverability of cleared generation is validated through transfer analysis modeling to ensure transmission reliability. If constraints arise, they are mitigated by adjusting CIL and CEL values as needed.

1.1.1 Study Improvements

The Planning Year 2025-2026 LOLE study incorporated the following improvements:

- **SERVM Improvements:** Enhancements made to SERVM resulted in reliability improvements driven primarily by a more realistic dispatch of demand response resources. In version 9 of SERVM, used for the Planning Year 2025-2026 LOLE analysis, demand response dispatch logic was improved to randomly cycle through demand response resources. This change had a positive impact on reliability because in version 7, used for the Planning Year 2024-2025 LOLE analysis, the dispatch order was fixed and would often happen to have more of the larger demand response units being called first. This in turn caused these larger units to achieve their seasonal run limits more frequently. This new random cycling logic for demand response resources modified the dispatch order for each iteration which allowed smaller demand response units to get called first more often. The overall impact is a modest improvement in reliability because the larger demand response units are not exhausted as often in the simulations as they were in prior models.
- **Improved Load Development Process:** This enhanced process aimed to better account for the correlation between load, weather, and the time of day, and to resolve unrealistic high-risk hours in the early mornings of the Winter season that were identified through concerns expressed by the IMM last year. The PY 2025-2026 load development process also better captured the relationship between higher load and temperature values that establishes a stronger representation of load behavior at more extreme temperatures than the prior load development process. Additional information on this load development process may be found in Section 3.4 of this study report.
- **Expanded consideration of outages driven by extreme cold temperatures**: The accounting of additional forced outages during extreme cold temperatures in the Fall, Winter, and Spring seasons was updated in the PRM and LRR calculations. For context, the LOLE model has historically utilized resource-specific five-year average EFORd values based on historical GADS data, which were updated from annualized EFORd to seasonalized EFORd in the PY 2023-2024 LOLE study. The cold weather outage adder was included in the LOLE model, starting with the PY 2024-2025 LOLE study, to better capture the historic seasonal availability of thermal resources during extreme cold temperatures. This was expanded upon in the PY 2025-2026 LOLE study to include the Fall and Spring seasons.

  Additional thermal forced outages are added to the model during times of extreme cold temperatures to better capture the magnitude of observed correlated outages. The magnitude of additional forced outages increases as temperatures decrease based on the relationship between forced outages and temperature determined from historical GADS and weather data. The modeling of additional forced outages in the Fall, Winter, and Spring seasons due to the adder induces a higher volume of forced outages in the model beyond just the average Fall, Winter, and Spring EFORd. Each LRZ has a unique outage/temperature profile based on actual historical forced outages. The incremental cold weather outages are not assigned to a particular resource but instead represent the aggregate impact on the system for coal, gas, and combined cycle resources.

  The accounting of reduced Unforced Capacity resulting from additional extreme cold weather outages was addressed in the most recent PRM and LRR calculations for the Fall and Spring seasons. A comparative

probabilistic analysis (with and without the cold weather outage adder) quantified the impact of modeling the cold weather outage adder profiles on the system-wide requirements for each season. This impact was distributed pro-rata to the zonal level based on the average magnitude of the zonal cold weather outage adder profiles used in the LRR calculations. The comparative probabilistic analysis resulted in the largest effects for the Winter season (7,265 MW) and minimal effects for the Fall (45 MW) and Spring (1,100 MW) seasons. Summer was not affected by these outages.

1.2 Planning Year 2025-2026 MISO Planning Reserve Margin Results

For Planning Year 2025-2026, the ratio of MISO capacity to forecasted MISO system peak demand yielded a Planning Reserve Margin UCAP of 7.9 percent for the Summer season. Numerous values and calculations went into determining the MISO system PRM ICAP and PRM UCAP (Table 1-2).

MISO Planning Reserve Margin (PRM)	PY 2025-2026 Summer	PY 2025-2026 Fall	PY 2025-2026 Winter	PY 2025-2026 Spring	Formula Key
MISO System Peak Demand (MW)	123,576	108,109	103,910	98,680	[A]
Installed Capacity (ICAP) (MW)	141,908	142,746	147,430	144,513	[B]
Unforced Capacity (UCAP) (MW)	132,389	131,554	126,573	131,289	[C]
Firm External Support ICAP (MW)	1,986	2,315	2,738	2,423	[D]
Firm External Support UCAP (MW)	1,935	2,215	2,594	2,309	[E]
Adjustment to ICAP (MW)	(960)	(9,590)	(6,110)	(10,000)	[F]
Adjustment to UCAP (MW)	(960)	(9,590)	(6,110)	(10,000)	[G]
ICAP PRM Requirement (PRMR) (MW)	142,934	135,472	144,058	136,937	[H] = [B]+[D]+[F]
UCAP PRM Requirement (PRMR) (MW)	133,363	124,179	123,058	123,598	[I] = [C]+[E]+[G]
MISO PRM ICAP	**15.7%**	**25.3%**	**38.6%**	**38.8%**	[J]=[H]-[A]/[A]
MISO PRM UCAP	**7.9%**	**14.9%**	**18.4%**	**25.3%**	[K]=[I]-[A]/[A]

Table 1-2: Planning Year 2025-2026 MISO System Planning Reserve Margins

1.2.1 Additional Risk Metric Statistics

In addition to the LOLE results, SERVM has the ability to calculate several other probabilistic metrics, shown below in Table 1-3. The values for Loss of Load Hours (LOLH) and Expected Unserved Energy (EUE) are calculated at the point where the annual LOLE is at 1 day in 10 years, or 0.1 LOLE for the Summer season, and for the off seasons, values of LOLH and EUE are calculated at the point where the seasonal LOLE is at 1 day in 100 years, or 0.01 LOLE. Loss of Load Hours is the number of hours during a given time period where demand exceeds generation. Like LOLE, LOLH is only measured on the daily peak hour. Expected Unserved Energy is the magnitude of the shortfall when demand exceeds generation and is measured on all hours of simulation.

MISO LOLE Statistics	PY 2025-2026 Summer	PY 2025-2026 Fall	PY 2025-2026 Winter	PY 2025-2026 Spring
Loss of Load Expectation (LOLE) [days/year]	0.100	0.010	0.010	0.010
Loss of Load Hours (LOLH) [hours/year]	0.252	0.015	0.021	0.013
Expected Unserved Energy (EUE) [megawatt-hours/year]	626.161	18.936	24.378	12.807

Table 1-3: PY 2025-2026 Additional Risk Metric Statistics

1.3 Comparison of PRM Targets Across 10 Years

Figure 1-1 compares the PRM UCAP values over the last 10 Planning Years. The last three data points show the Summer PRM UCAP values following FERC's acceptance of MISO's seasonal capacity construct, while the prior data points are indicative of the PRM UCAP under the annual capacity construct.

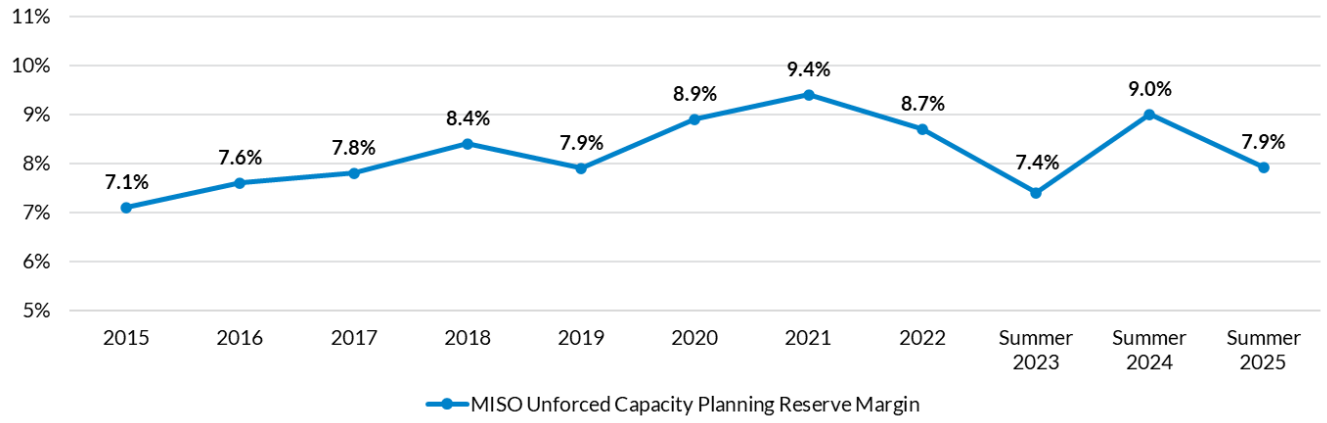


Figure 1-1: Comparison of UCAP PRM Targets Across 10 Years

1.4 Comparison of Planning Year 2024-2025 to Planning Year 2025-2026

Multiple sensitivity analyses were performed to independently quantify the year-over-year changes to the seasonal Planning Reserve Margin (PRM) values driven by various model improvements or model data replacement. The incremental impact to the seasonal PRM values from Planning Year 2024-2025 to Planning Year 2025-2026 due to specific changes to the LOLE model are shown in the waterfall charts below (Figure 1-2, Figure 1-3, Figure 1-4, and Figure 1-5). The following subsections provide more details around each of the sensitivities.

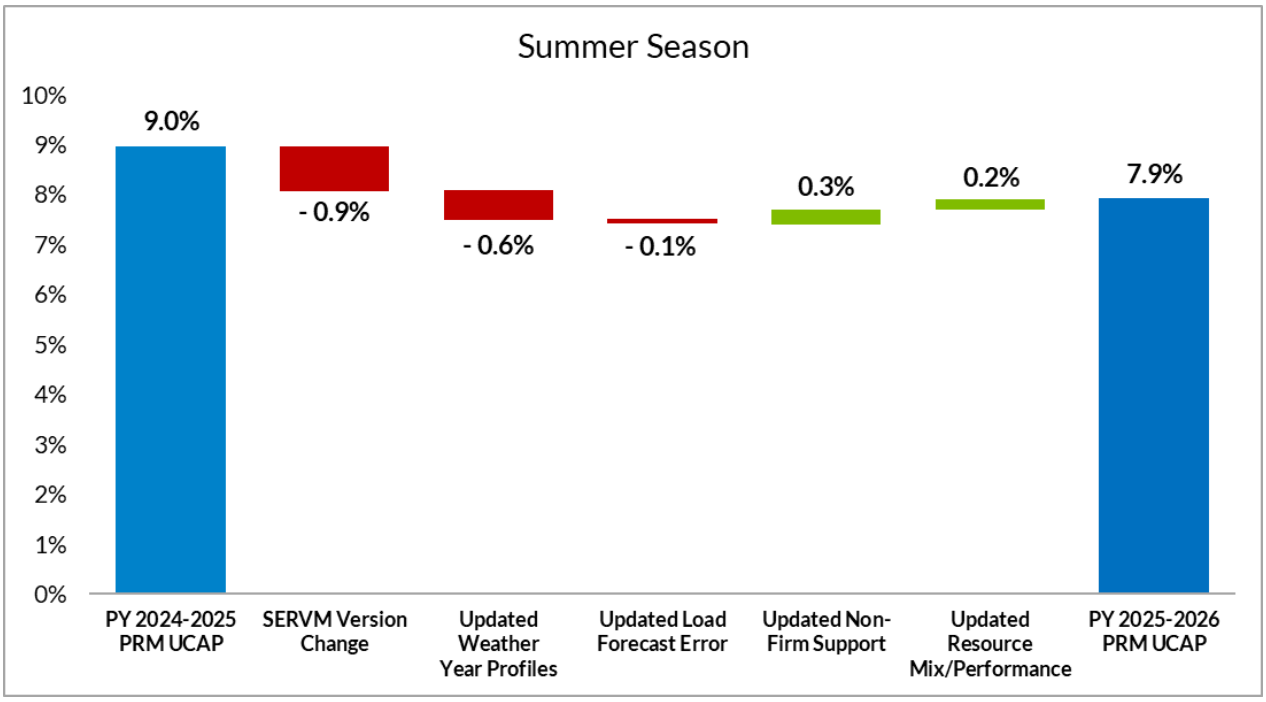


Figure 1-2: Waterfall Chart of Summer PRM UCAP from PY 2024-2025 to PY 2025-2026

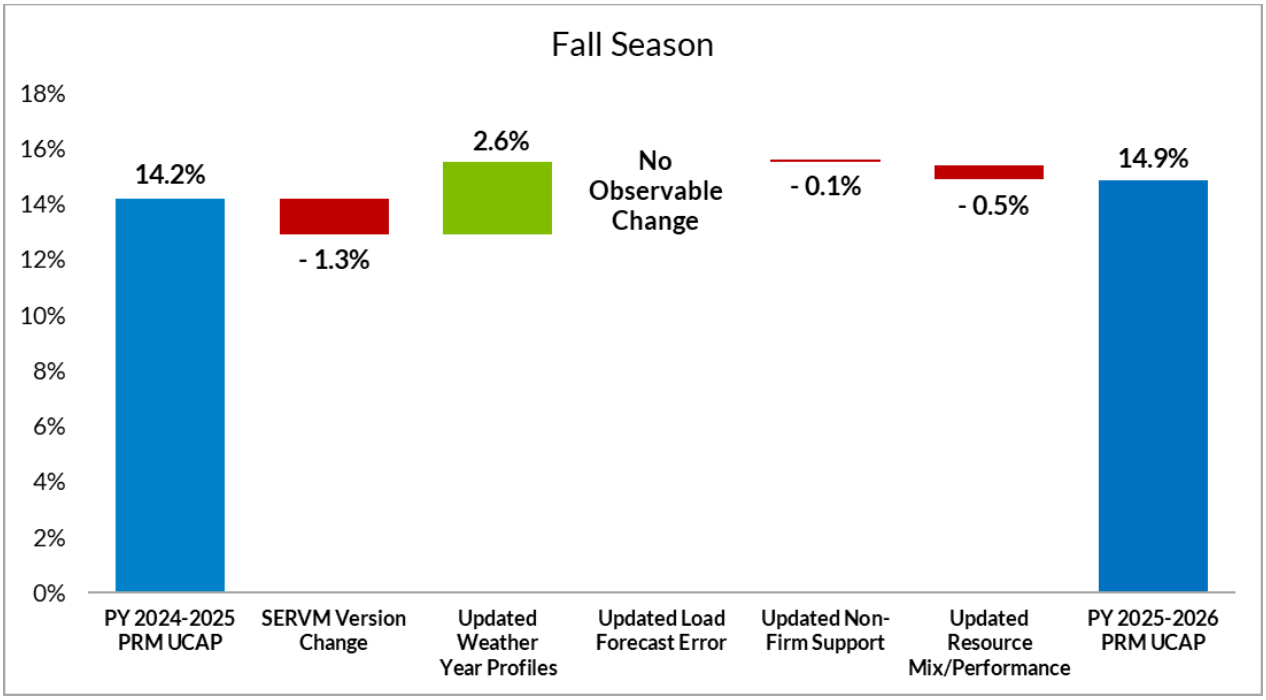


Figure 1-3: Waterfall Chart of Fall PRM UCAP from PY 2024-2025 to PY 2025-2026

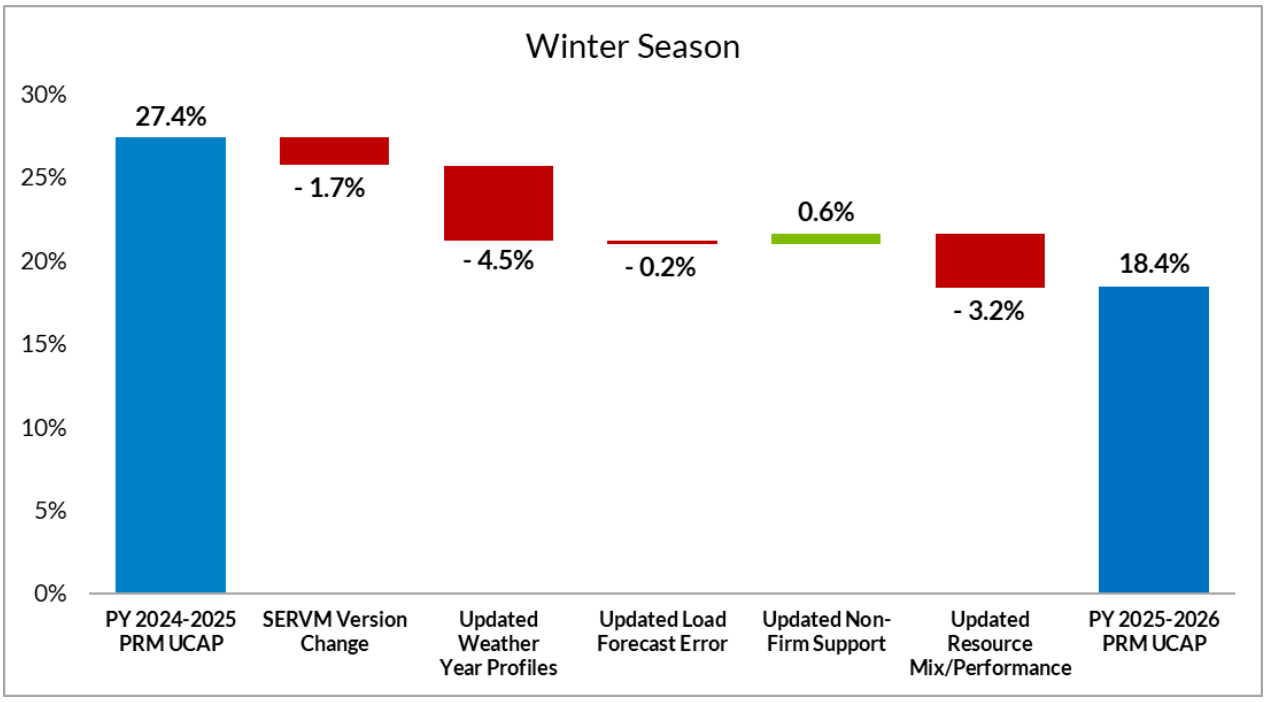


Figure 1-4: Waterfall Chart of Winter PRM UCAP from PY 2024-2025 to PY 2025-2026

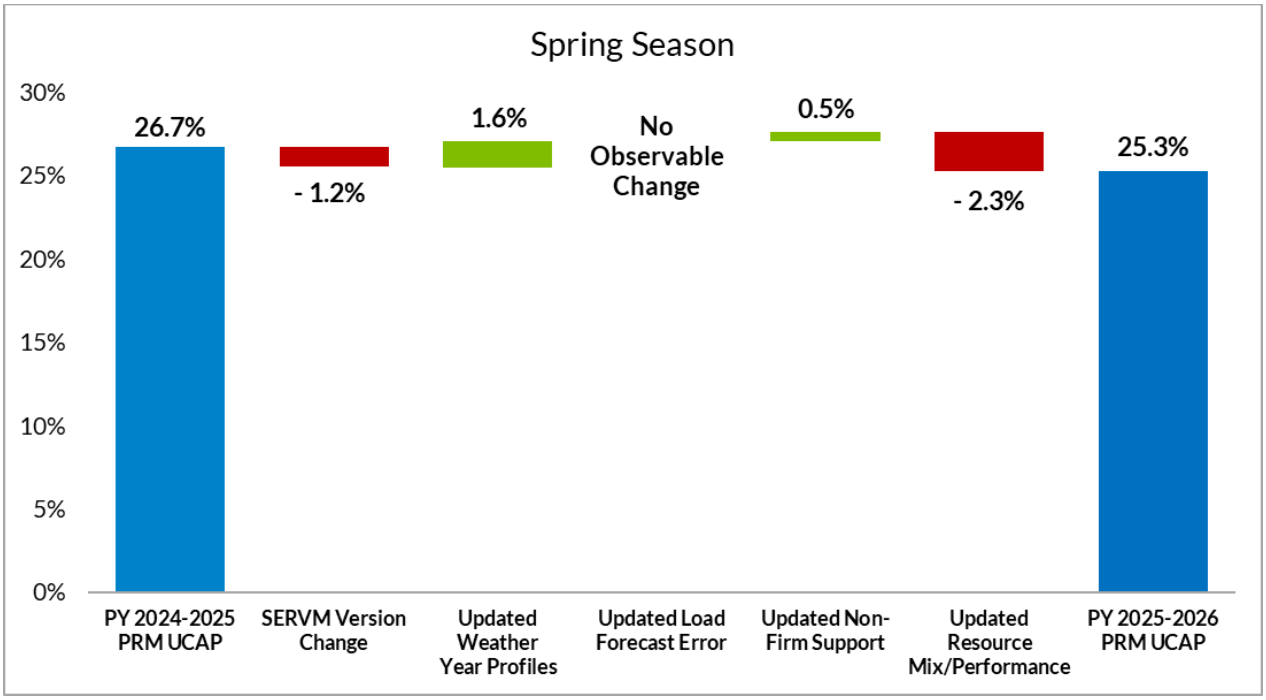


Figure 1-5: Waterfall Chart of Spring PRM UCAP from PY 2024-2025 to PY 2025-2026

1.4.1 Waterfall Chart Details

1.4.1.1 SERVM Improvements

Enhancements made to SERVM for the Planning Year 2025-2026 LOLE study resulted in reliability improvements driven primarily by a more realistic dispatch of demand response and storage resources. Version 9 of SERVM was used in this year's LOLE study.

1.4.1.2 Updated Weather Year Profiles

Every year during the annual refresh of the LOLE model, the oldest weather year is removed and a new weather year is added. In this sensitivity category, MISO analyzes the impacts of all updated hourly profiles that are tied to specific weather years, including profiles for load, wind generation, solar generation, and cold weather outage adders. Since all these variables are tied to specific weather years in the model, it is not possible to isolate the individual impacts of these variables.

1.4.1.3 Updated Non-Firm Support

The probabilistic distribution of seasonal non-firm support is independent of specific weather years and is the next input dataset that is replaced in the year-over-year LOLE model refresh. More information on the modeling of non-firm support can be found in Section 3.5.

1.4.1.4 Updated Resource Mix / Performance

Changes in resource capabilities from Planning Year 2024-2025 are driven by updated seasonal forced outage rates, updated annualized planned maintenance outage rates, new units, retirements, suspensions, replacements, and general changes in the MISO resource fleet.

2 Local Resource Zone Analysis – LRR Results

2.1 Planning Year 2025-2026 Local Resource Zone Analysis

MISO calculated the per-unit LRR of LRZ seasonal peak demand for Planning Year 2025-2026 on a seasonal basis (Table 2-1, Table 2-2, Table 2-3, and Table 2-4). The Unforced Capacity (UCAP) values in the seasonal LRR tables reflect the assumed seasonal UCAP within each LRZ, including Coordinating Owner External Resources and Border External Resources. The adjustments to UCAP values are the megawatt adjustments needed in each LRZ so that the seasonal LOLE criteria are met. LRR is the summation of the zone's total capacity and adjustment to capacity needed to achieve the seasonal LOLE criteria. The LRR is then divided by each LRZ's forecasted seasonal peak demand to determine the per-unit LRR UCAP. The Planning Year 2025-2026 per-unit LRR UCAP values will be multiplied by the updated seasonal peak demand forecasts submitted for the 2025-2026 PRA to determine each LRZ's LRR. The MISO system-wide and zonal peak demand timestamps for all 30 years modeled in the LOLE study are shown in Table 2-5. The peak demand timestamps are subject to the load development process and are not necessarily the actual historical peak days and times.

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
PY 2025-2026 Local Reliability Requirements - Summer 2025											
Installed Capacity (ICAP) (MW)	20,621	14,053	11,537	9,290	6,452	17,290	22,708	11,194	22,675	6,086	[A]
Unforced Capacity (UCAP) (MW)	19,636	13,339	11,047	8,726	5,925	15,581	21,136	10,453	21,046	5,501	[B]
Adjustment to UCAP (MW)	1,733	1,067	2,527	2,520	4,318	6,570	2,708	956	3,570	1,975	[C]
Local Reliability Requirement (LRR) UCAP (MW)	21,369	14,406	13,574	11,246	10,243	22,151	23,844	11,408	24,616	7,476	[D]=[B]+[C]
Peak Demand (MW)	17,889	12,694	10,295	8,786	7,873	17,555	20,953	8,448	21,676	5,166	[E]
LRR UCAP per-unit of LRZ Peak Demand	**119.5%**	**113.5%**	**131.8%**	**128.0%**	**130.1%**	**126.2%**	**113.8%**	**135.0%**	**113.6%**	**144.7%**	[F]=[D]/[E]

Table 2-1: Planning Year 2025-2026 LRZ Local Reliability Requirements for Summer 2025

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
PY 2025-2026 Local Reliability Requirements - Fall 2025											
Installed Capacity (ICAP) (MW)	20,658	14,203	12,874	9,171	6,442	17,232	22,539	10,910	22,618	6,099	[A]
Unforced Capacity (UCAP) (MW)	19,554	13,196	12,295	8,486	5,883	15,652	20,755	10,184	20,175	5,374	[B]
Adjustment to UCAP (MW)	165	50	1,590	1,565	3,785	5,154	1,937	888	3,449	1,908	[C]
Local Reliability Requirement (LRR) UCAP (MW)	19,719	13,246	13,885	10,051	9,668	20,806	22,692	11,072	23,624	7,282	[D]=[B]+[C]
Peak Demand (MW)	15,313	10,839	9,034	7,616	7,084	15,859	18,085	7,537	19,721	4,676	[E]
LRR UCAP per-unit of LRZ Peak Demand	**128.8%**	**122.2%**	**153.7%**	**132.0%**	**136.5%**	**131.2%**	**125.5%**	**146.9%**	**119.8%**	**155.7%**	[F]=[D]/[E]

Table 2-2: Planning Year 2025-2026 LRZ Local Reliability Requirements for Fall 2025

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
PY 2025-2026 Local Reliability Requirements - Winter 2025-2026											
Installed Capacity (ICAP) (MW)	20,600	13,959	12,919	9,288	6,879	17,115	23,377	12,008	24,649	6,635	[A]
Unforced Capacity (UCAP) (MW)	18,563	12,282	11,640	6,065	4,655	13,672	21,359	10,503	22,163	5,671	[B]
Adjustment to UCAP (MW)	995	950	1,950	3,023	4,152	5,950	-840	1,278	3,279	1,617	[C]
Local Reliability Requirement (LRR) UCAP (MW)	19,558	13,232	13,591	9,088	8,806	19,622	20,519	11,781	25,442	7,288	[D]=[B]+[C]
Peak Demand (MW)	15,442	9,781	8,328	7,664	7,023	15,729	14,177	7,524	19,613	4,477	[E]
LRR UCAP per-unit of LRZ Peak Demand	**126.7%**	**135.3%**	**163.2%**	**118.6%**	**125.4%**	**124.7%**	**144.7%**	**156.6%**	**129.7%**	**162.8%**	[F]=[D]/[E]

Table 2-3: Planning Year 2025-2026 LRZ Local Reliability Requirements for Winter 2025-2026

Local Resource Zone (LRZ)	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS	Formula Key
PY 2025-2026 Local Reliability Requirements - Spring 2026											
Installed Capacity (ICAP) (MW)	19,862	14,049	12,380	9,293	7,423	17,188	22,881	11,694	23,337	6,406	[A]
Unforced Capacity (UCAP) (MW)	18,613	13,073	11,555	7,865	5,961	15,273	20,822	10,613	21,646	5,869	[B]
Adjustment to UCAP (MW)	990	600	1,540	1,910	3,470	4,948	668	199	3,333	1,963	[C]
Local Reliability Requirement (LRR) UCAP (MW)	19,604	13,673	13,094	9,775	9,431	20,221	21,490	10,811	24,979	7,832	[D]=[B]+[C]
Peak Demand (MW)	15,285	10,270	8,246	6,537	6,465	14,570	16,293	6,813	19,333	4,381	[E]
LRR UCAP per-unit of LRZ Peak Demand	**128.3%**	**133.1%**	**158.8%**	**149.5%**	**145.9%**	**138.8%**	**131.9%**	**158.7%**	**129.2%**	**178.8%**	[F]=[D]/[E]

Table 2-4: Planning Year 2025-2026 LRZ Local Reliability Requirements for Spring 2026

Weather Year Time of Peak Demand (EST HE)	MISO	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS
1994	7/6/94 16:00	8/25/94 17:00	8/25/94 16:00	7/19/94 18:00	7/6/94 17:00	1/18/94 15:00	1/19/94 8:00	7/6/94 15:00	1/18/94 21:00	7/3/94 18:00	1/18/94 20:00
1995	7/12/95 17:00	7/13/95 19:00	7/13/95 16:00	7/12/95 16:00	7/12/95 17:00	8/18/95 19:00	7/14/95 19:00	7/14/95 14:00	7/28/95 17:00	7/11/95 18:00	7/28/95 16:00
1996	8/6/96 16:00	7/18/96 16:00	8/14/96 16:00	7/18/96 17:00	7/18/96 18:00	7/18/96 19:00	2/2/96 19:00	8/7/96 16:00	6/30/96 21:00	2/5/96 6:00	7/3/96 16:00
1997	7/14/97 17:00	7/16/97 19:00	7/16/97 17:00	7/25/97 17:00	7/18/97 17:00	7/18/97 19:00	7/14/97 16:00	7/14/97 17:00	7/24/97 17:00	1/17/97 8:00	7/24/97 17:00
1998	7/20/98 16:00	7/14/98 18:00	7/14/98 18:00	7/20/98 19:00	7/21/98 18:00	7/21/98 16:00	7/21/98 17:00	7/21/98 15:00	7/7/98 15:00	8/28/98 18:00	8/27/98 18:00
1999	7/29/99 17:00	7/29/99 17:00	7/30/99 13:00	7/29/99 18:00	7/18/99 18:00	7/29/99 16:00	7/30/99 16:00	7/30/99 16:00	7/29/99 18:00	8/5/99 17:00	8/19/99 17:00
2000	8/31/00 17:00	7/8/00 17:00	7/14/00 16:00	9/2/00 17:00	7/10/00 18:00	8/17/00 18:00	8/9/00 18:00	6/10/00 16:00	7/20/00 14:00	8/26/00 17:00	8/30/00 16:00
2001	7/31/01 17:00	7/31/01 17:00	7/31/01 17:00	7/31/01 16:00	7/23/01 16:00	7/23/01 17:00	8/8/01 17:00	8/8/01 17:00	7/11/01 17:00	8/20/01 16:00	7/11/01 16:00
2002	7/8/02 16:00	7/1/02 19:00	7/18/02 15:00	7/8/02 18:00	7/9/02 17:00	7/23/02 17:00	8/23/02 16:00	7/1/02 16:00	8/6/02 17:00	7/18/02 16:00	7/9/02 17:00
2003	8/26/03 16:00	8/18/03 19:00	8/21/03 16:00	8/25/03 17:00	8/26/03 16:00	8/21/03 16:00	8/27/03 17:00	8/21/03 18:00	8/18/03 15:00	1/24/03 10:00	8/18/03 18:00
2004	7/22/04 16:00	7/21/04 19:00	6/8/04 14:00	7/13/04 18:00	7/22/04 16:00	7/22/04 17:00	12/24/04 10:00	6/9/04 12:00	7/14/04 17:00	8/1/04 16:00	7/31/04 16:00
2005	7/25/05 16:00	7/22/05 18:00	8/10/05 14:00	7/25/05 17:00	7/25/05 18:00	7/25/05 18:00	7/25/05 17:00	6/28/05 16:00	7/22/05 18:00	7/25/05 16:00	7/25/05 18:00
2006	7/31/06 17:00	7/31/06 17:00	7/31/06 18:00	7/19/06 19:00	7/31/06 17:00	8/2/06 18:00	7/31/06 17:00	7/31/06 17:00	7/21/06 15:00	12/8/06 8:00	7/18/06 17:00
2007	8/1/07 17:00	7/26/07 15:00	7/10/07 15:00	7/17/07 18:00	8/28/07 17:00	8/15/07 16:00	8/29/07 17:00	7/31/07 18:00	8/9/07 17:00	8/11/07 18:00	8/14/07 17:00
2008	7/16/08 17:00	7/29/08 18:00	7/17/08 15:00	7/17/08 17:00	7/18/08 17:00	7/18/08 17:00	8/23/08 16:00	8/24/08 12:00	8/2/08 18:00	7/26/08 16:00	7/28/08 17:00
2009	6/24/09 17:00	5/19/09 19:00	6/24/09 17:00	6/22/09 18:00	6/22/09 17:00	6/22/09 17:00	1/16/09 8:00	6/24/09 16:00	6/22/09 16:00	7/2/09 16:00	6/22/09 18:00

Weather Year Time of Peak Demand (EST HE)	MISO	LRZ-1 MN/ND	LRZ-2 WI	LRZ-3 IA	LRZ-4 IL	LRZ-5 MO	LRZ-6 IN	LRZ-7 MI	LRZ-8 AR	LRZ-9 LA/TX	LRZ-10 MS
2010	8/10/10 17:00	8/9/10 18:00	7/9/10 17:00	7/14/10 17:00	7/5/10 17:00	8/3/10 16:00	8/10/10 18:00	7/6/10 16:00	8/3/10 17:00	8/2/10 15:00	8/2/10 16:00
2011	7/20/11 17:00	7/18/11 18:00	7/20/11 15:00	8/2/11 17:00	8/24/11 14:00	9/1/11 16:00	9/2/11 18:00	7/21/11 15:00	8/3/11 18:00	8/18/11 16:00	7/13/11 16:00
2012	7/6/12 16:00	7/6/12 18:00	7/4/12 13:00	7/25/12 18:00	7/6/12 16:00	6/28/12 18:00	7/7/12 18:00	7/6/12 14:00	7/28/12 16:00	6/25/12 18:00	7/4/12 16:00
2013	7/19/13 16:00	8/27/13 18:00	7/19/13 14:00	8/30/13 17:00	8/30/13 17:00	8/30/13 16:00	8/30/13 16:00	7/19/13 14:00	8/30/13 17:00	8/5/13 17:00	7/30/13 17:00
2014	7/22/14 17:00	7/21/14 18:00	7/22/14 16:00	7/22/14 17:00	8/22/14 17:00	8/26/14 16:00	8/26/14 16:00	6/17/14 17:00	1/7/14 9:00	1/7/14 9:00	1/28/14 20:00
2015	7/28/15 17:00	7/14/15 18:00	8/3/15 17:00	7/13/15 15:00	7/28/15 18:00	7/28/15 17:00	9/8/15 16:00	7/29/15 16:00	7/29/15 16:00	1/8/15 7:00	7/30/15 15:00
2016	7/20/16 16:00	7/21/16 18:00	8/10/16 14:00	7/20/16 17:00	8/10/16 15:00	7/23/16 16:00	8/10/16 17:00	8/4/16 15:00	7/21/16 15:00	8/31/16 16:00	7/7/16 15:00
2017	7/20/17 16:00	7/6/17 17:00	7/20/17 14:00	7/20/17 16:00	7/20/17 16:00	7/22/17 18:00	9/22/17 15:00	6/12/17 15:00	7/20/17 15:00	7/19/17 16:00	7/20/17 16:00
2018	7/5/18 14:00	6/29/18 15:00	8/15/18 15:00	8/3/18 16:00	8/16/18 16:00	8/6/18 16:00	1/16/18 19:00	7/5/18 14:00	1/2/18 8:00	8/14/18 16:00	1/17/18 9:00
2019	7/19/19 15:00	7/19/19 17:00	7/16/19 16:00	7/19/19 16:00	7/1/19 17:00	9/17/19 16:00	7/2/19 16:00	7/19/19 13:00	8/13/19 14:00	7/7/19 15:00	7/10/19 14:00
2020	7/18/20 16:00	7/8/20 18:00	7/8/20 16:00	8/26/20 15:00	8/26/20 15:00	7/11/20 16:00	8/25/20 15:00	7/3/20 16:00	7/18/20 15:00	7/10/20 16:00	7/18/20 14:00
2021	7/28/21 15:00	7/5/21 17:00	8/20/21 15:00	6/17/21 16:00	7/7/21 15:00	2/14/21 10:00	8/24/21 16:00	7/7/21 13:00	2/16/21 7:00	8/23/21 16:00	8/11/21 15:00
2022	6/21/22 16:00	6/20/22 16:00	6/21/22 16:00	8/2/22 16:00	7/20/22 16:00	7/22/22 16:00	7/5/22 16:00	6/21/22 16:00	7/26/22 15:00	6/23/22 17:00	6/21/22 16:00
2023	8/23/23 17:00	8/23/23 17:00	8/23/23 15:00	8/23/23 16:00	7/5/23 14:00	8/25/23 16:00	8/24/23 17:00	8/23/23 17:00	7/28/23 16:00	8/27/23 15:00	8/24/23 15:00

Table 2-5: Modeled Peak Demand Days/Hours by Local Resource Zone

3 Loss of Load Expectation Analysis

3.1 LOLE Modeling Input Data and Assumptions

MISO uses a program developed and maintained by Astrapé Consulting called Strategic Energy & Risk Valuation Model (SERVM) to calculate LOLE for the applicable Planning Year. SERVM uses a sequential Monte Carlo simulation to model a generation system and to assess the system's reliability, based on any number of interconnected areas. SERVM calculates LOLE for the MISO system and for each LRZ by stepping through the year chronologically and taking into account generation, load, load modifying resources, generator forced outages, generator planned maintenance outages, weather and economic uncertainty, and external support from neighboring regions.

Building the SERVM model is the most time-consuming task of the LOLE study. Several sensitivities are built to determine how specific inputs and variables impact the results. The base case models determine the seasonal MISO Planning Reserve Margin Unforced Capacity (PRM UCAP) and Local Reliability Requirement (LRR) values for each LRZ for future Planning Years one, four, and six.

3.1.1 Resource Inclusion

Planning Year 2025-2026

The Planning Year 2025-2026 LOLE study used converted capacity from the 2024-2025 PRA as a starting point for which resources to include in the study. This ensured that only resources eligible as Planning Resources were included in the LOLE study. For the PY 2025-2026 LOLE study, internal MISO CPNode resources that were excluded from the auction clearing process but were used to satisfy Resource Adequacy Requirements through a Fixed Resource Adequacy Plan (FRAP) or that offered and subsequently cleared the 2024-2025 PRA in any season were included in the LOLE model for all seasons. Resources that were on an approved Attachment Y suspension or retirement, or had an approved IMM exemption, were excluded from the LOLE model in their respective seasons. External resources were included for only the corresponding seasons in which they were included in a FRAP or offered in the 2024-2025 PRA.

Upcoming changes for Planning Year 2026-2027

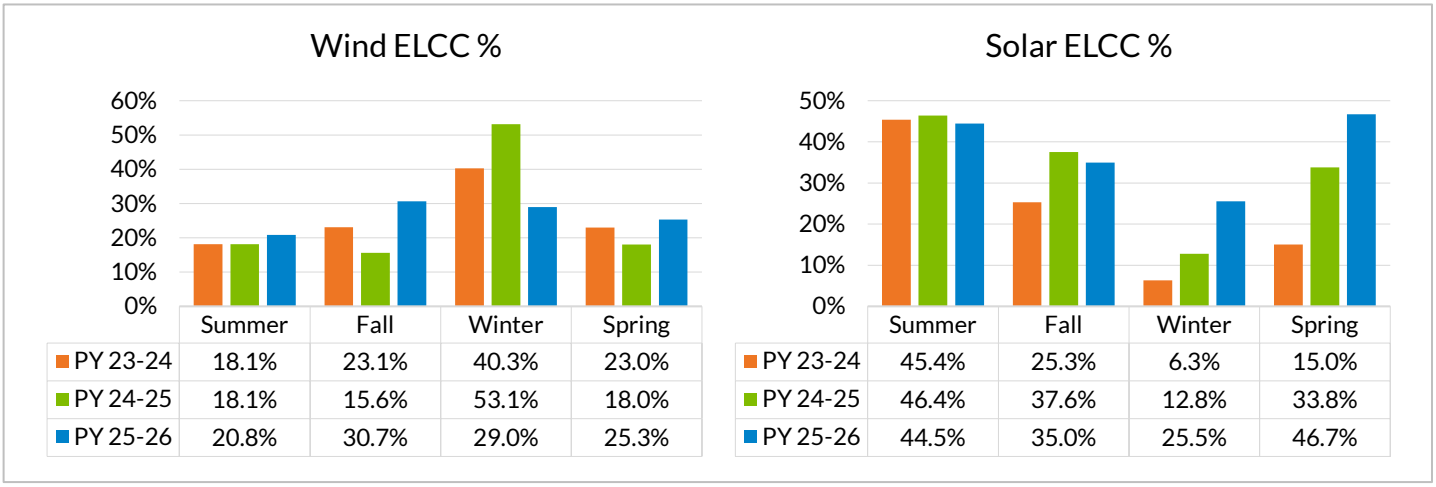
In July 2024, MISO opened a formal feedback request with stakeholders to better define a set of criteria for resource inclusion within the LOLE model that would be implemented for the PY 2026-2027 LOLE study and beyond. From the feedback, it was determined that MISO will include resources for each season a resource is included in a FRAP or offered into the most recent PRA, with an exception for external resources. External resources will be included in the LOLE model for each season that an external resource is included in a FRAP or cleared in the most recent PRA. The rationale is that external resource offer behavior can differ from one year to the next, as they are not subject to economic withholding in MISO and do not have any obligation to serve MISO load if they do not make a commitment to do so through the PRA.

3.1.2 Effective Load Carrying Capability (ELCC)

Each year, MISO performs seasonal Effective Load Carrying Capability (ELCC) analyses for wind and solar resources to quantify their average capacity contribution to determine season-wide capacity values for use in the seasonal Planning Reserve Margin (PRM) and Local Reliability Requirement (LRR) calculations. Wind and solar generation is represented in the model with 30-year hourly capacity factor profiles.

Seasonal wind ELCC determines the allocable Seasonal Accredited Capacity (SAC) for in-service CPNode wind resources for the prompt year PRA. Solar ELCC is not used for accreditation and is only used for calculating solar UCAP in the PRM and LRR equations. More details regarding wind and solar accreditation will be provided in the Planning Year 2025-2026 Wind and Solar Capacity Credit Report.

The Figure 3-1 below details the resulting LOLE study ELCC percentages over the last three Planning Years.



	Summer	Fall	Winter	Spring
PY 23-24	18.1%	23.1%	40.3%	23.0%
PY 24-25	18.1%	15.6%	53.1%	18.0%
PY 25-26	20.8%	30.7%	29.0%	25.3%

	Summer	Fall	Winter	Spring
PY 23-24	45.4%	25.3%	6.3%	15.0%
PY 24-25	46.4%	37.6%	12.8%	33.8%
PY 25-26	44.5%	35.0%	25.5%	46.7%

Figure 3-1: Planning Year 2025-2026 Wind and Solar ELCC Trends

Over the past several years, variability in the non-Summer season results have been observed for both wind and for solar. This is largely driven by the evolving resource mix within the MISO system and the resulting hours of risk for each year's model. Additionally, due to the Summer season having a higher LOLE criterion of 0.1 LOLE (or 1 day of loss of load in 10 years) at the system-wide level, there is a greater volume of impacted Loss of Load Hours (LOLH) in the Summer compared to the other seasons. This results in a larger sampling of wind and solar generation used in the ELCC analyses for Summer than in the other seasons.

Seasonal Drivers of Change from Planning Year 2024-2025 to Planning Year 2025-2026 are detailed below:

- **Summer**: The majority of the risk in the Planning Year 2024-2025 Summer season was observed in July. However, in Planning Year 2025-2026, there was an increase in prolonged risk observed in August. This resulted in wind generation impacting more hours during the Summer season and solar impacting slightly less as LOLH extended further into evening hours.
- **Fall**: In Planning Year 2024-2025, September was the only month that exhibited risk for the MISO system in the Fall season. In Planning Year 2025-2026, September risk increased and November demonstrated some morning and evening risk hours. Due to the shift in Fall risk hours, the number of hours where wind generation was able to be impactful increased, while the number of hours where solar could be impactful decreased.
- **Winter**: Changes in ELCC values for the Winter season were primarily driven by Planning Year 2025-2026 load development process enhancements. These enhancements shifted risk hours to later in the day where wind performed worse and solar was able to perform better during the full set of risk hours.
- **Spring**: During this season, MISO saw an increase in both wind and solar ELCC values. In Planning Year 2025-2026, Spring risk materialized during several evening hours in March, and the overall magnitude of risk increased in comparison with Planning Year 2024-2025. This allowed both wind and solar generation to become more impactful during hours of greater renewable output.

3.2 MISO Generation

3.2.1 Thermal Units

All MISO internal thermal Planning Resources were modeled in the LRZ in which they are physically located, except for pseudo-tied resources. Additionally, Coordinating Owner External Resources and Border External Resources were modeled as being internal to the LRZ in which they are committed to serving load.

Seasonal forced outage rates and annualized planned maintenance outage rates were calculated over a five-year period (January 2019 to December 2023) for each resource. Some resources did not have five years of historical data in MISO's Generator Availability Data System (PowerGADS). However, if they had at least three consecutive months of outage data, resource-specific information was used to calculate their seasonal forced and planned maintenance outage rates. Resources with fewer than three consecutive months of resource-specific outage data were assigned the corresponding MISO seasonal class average forced outage rate and annualized planned maintenance outage rate based on their resource type. The overall MISO ICAP-weighted seasonal class average forced outage rates and annualized planned maintenance outage rate were applied in lieu of class averages for classes with fewer than 30 resources reporting 12 or more months of data.

The historical class average outage rates as well as the MISO system-wide weighted average forced outage rate are provided in Table 3-1 to show the year-over-year trends, as well as in Table 3-2 on a seasonal basis for the prompt Planning Year.

Pooled EFORd GADS Years	**2019-2023 (%)**	**2018-2022 (%)**	**2017-2021 (%)**	**2016-2020 (%)**	**2015-2019 (%)**	**2014-2018 (%)**
LOLE Study Planning Year	**PY 2025-2026** Summer	**PY 2024-2025** Summer	**PY 2023-2024** Summer	**PY 2022-2023** Annualized	**PY 2021-2022** Annualized	**PY 2020-2021** Annualized
Combined Cycle	5.26	5.92	5.54	5.85	5.52	5.70
Combustion Turbine (0-50 MW)	10.80	7.65	7.37	15.25	15.83	17.88
Combustion Turbine (50+ MW)	4.72	4.88	4.07	4.36	4.76	4.65
Diesel Engines	17.52	17.14	12.79	7.25	10.05	23.53
Fluidized Bed Combustion	*	*	*	*	*	*
Hydro (0-30 MW)	*	*	*	*	*	*
Hydro (30+ MW)	*	*	*	*	*	*
Nuclear	*	*	*	*	*	*
Pumped Storage	*	*	*	*	*	*
Steam – Coal (0-400 MW)	11.76	8.22	7.03	9.91	8.78	8.15
Steam - Coal (400-1,000 MW)	8.84	8.62	8.06	9.00	9.02	8.87
Steam - Gas	11.32	14.04	12.48	11.84	12.91	12.54
Steam - Oil	*	*	*	*	*	*
Steam - Waste Heat	*	*	*	*	*	*
Steam - Wood	*	*	*	*	*	*
MISO Weighted System-wide	7.76	8.24	8.23	9.04	9.36	9.24

Table 3-1: Historical Class Average Forced Outage Rates

Pooled EFORd GADS Years	2019-2023 (%)	2019-2023 (%)	2019-2023 (%)	2019-2023 (%)
LOLE Study Planning Year 2025-2026	**Summer 2025**	**Fall 2025**	**Winter 2025-2026**	**Spring 2026**
Combined Cycle	5.26	6.95	5.16	5.93
Combustion Turbine (0-50 MW)	10.80	13.42	33.67	15.79
Combustion Turbine (50+ MW)	4.72	7.96	12.50	5.31
Diesel Engines	17.52	31.84	24.53	23.91
Fluidized Bed Combustion	*	*	*	*
Hydro (0-30 MW)	*	*	*	*
Hydro (30+ MW)	*	*	*	*
Nuclear	*	*	*	*
Pumped Storage	*	*	*	*
Steam – Coal (0-400 MW)	11.76	15.27	12.68	11.17
Steam - Coal (400-1,000 MW)	8.84	9.20	9.83	9.94
Steam - Gas	11.32	12.91	9.83	9.32
Steam - Oil	*	*	*	*
Steam - Waste Heat	*	*	*	*
Steam - Wood	*	*	*	*
MISO Weighted System-wide	7.76	8.93	10.48	9.70

Table 3-2: Planning Year 2025-2026 Seasonal Class Average Forced Outage Rates

3.2.2 Behind-the-Meter Generation

Behind-the-Meter Generation data came from the Module E Capacity Tracking (MECT) tool. Behind-the-Meter Generation backed by thermal resources were explicitly modeled as any other thermal generator with a monthly capability and forced outage rate. Behind-the-Meter Generation backed by intermittent resources were modeled at their expected seasonal availability.

3.2.3 Attachment Y

MISO obtained information on generating resources with approved suspensions or retirements (as of June 1, 2024) through MISO's Attachment Y process. Any resource with an approved retirement or suspension in Planning Year 2025-2026 was excluded from the year-one analysis during the months in which the resource had been approved to be out of service. This same methodology is used for the four- and six-year analyses.

3.2.4 Future Generation

The LOLE model included resources with a signed and executed Generator Interconnection Agreement (as of June 1, 2024). These future resources were assigned seasonal class average forced outage rates and planned maintenance outage rates based on their resource class. Future thermal generation and upgrades were added to the LOLE model based on resource information in the MISO Generator Interconnection Queue. Resources with a planned upgrade during the study period reflect the megawatt increase for each month, beginning the month the upgrade is expected to be completed. The LOLE analysis includes future wind and solar generation, tied to the same hourly wind and solar profiles used for existing wind and solar resources in the model. In the LOLE model, resources with a signed and

executed GIA receive a postponement to their anticipated in-service dates relative to the average delays per resource type observed by the Generation Interconnection team at MISO.

3.2.5 Intermittent Resources

Intermittent resources include solar, wind, biomass, battery storage, and run-of-river hydro. Most intermittent resources submit historical output data during seasonal peak hours, defined as hours ending 15, 16, and 17 EST for Summer, Fall, and Spring, and hours ending 8, 9, 19, and 20 for Winter. Non-CPNode wind and battery storage resources are exceptions to this and only submit historical output data for the top eight seasonal coincident peaks for the last three Planning Years for which data is available. This data is averaged at the seasonal level and modeled in the LOLE analysis as seasonal effective capacity for all months within a given season. Each individual resource is modeled in the LRZ corresponding to its load obligation.

Using historical wind operational data from 279 front-of-meter wind resources from 2013 to 2023, normalized hourly capacity profiles were developed and aggregated at the LRZ level to represent hourly wind capability in the model. As a result of the LOLE analysis that is based on 30 weather years (1994 – 2023), synthetic shapes were developed by Astrapé for the 1994 – 2013 period based on historical wind performance and temperatures. Once the weather and wind performance matching has been performed, the data is analyzed as a function of load to ensure the variability around the load profiles is reasonable.

Solar profiles were also developed by Astrapé using historical solar irradiance data from the NREL National Solar Radiation Database (NSRDB) from 1998 – 2023.

3.2.6 Demand Response

Demand response programs and their capabilities came from their corresponding registrations in the MECT tool. These resources were explicitly modeled as dispatch-limited resources and are the last set of resources dispatched by the model in an effort to avoid LOLE. Each demand response program was modeled individually with a monthly capability, limited by duration and the number of times each program can be called upon for each season.

3.3 MISO Capacity

The following charts and tables below list the total Installed Capacity (ICAP) values by resource type and LRZ in the PY 2025-2026 LOLE model. Every July, MISO presents the preliminary capacity in the prompt year LOLE model at the LOLEWG and, starting with PY 2025-2026, MISO published the final ICAP values per zone and per season in its LOLE study report.

PY 2025-2026 ICAP MW, Summer											
Resource Type	**LRZ1**	**LRZ2**	**LRZ3**	**LRZ4**	**LRZ5**	**LRZ6**	**LRZ7**	**LRZ8**	**LRZ9**	**LRZ10**	**MISO**
Thermal	15,467	11,882	7,659	7,532	5,946	14,049	19,291	9,831	21,917	5,743	119,315
Demand Response	1,879	693	504	435	184	1,695	1,294	790	335	45	7,852
BTMG	1,460	339	603	310	97	351	1,073	17	20	104	4,373
Battery Storage	0	0	0	0	0	101	0	0	0	0	101
Wind	7,285	893	12,782	1,897	406	1,281	3,606	0	0	185	28,335
Solar	212	1,891	224	1,390	0	1,393	639	1,108	392	351	7,599
Run-of-River/Biomass	205	113	10	0	142	208	15	64	229	0	986
Total	**26,507**	**15,810**	**21,782**	**11,564**	**6,774**	**19,078**	**25,917**	**11,810**	**22,892**	**6,427**	**168,561**

Table 3-3: Summer Total Installed Capacity by Resource Type and Local Resource Zone

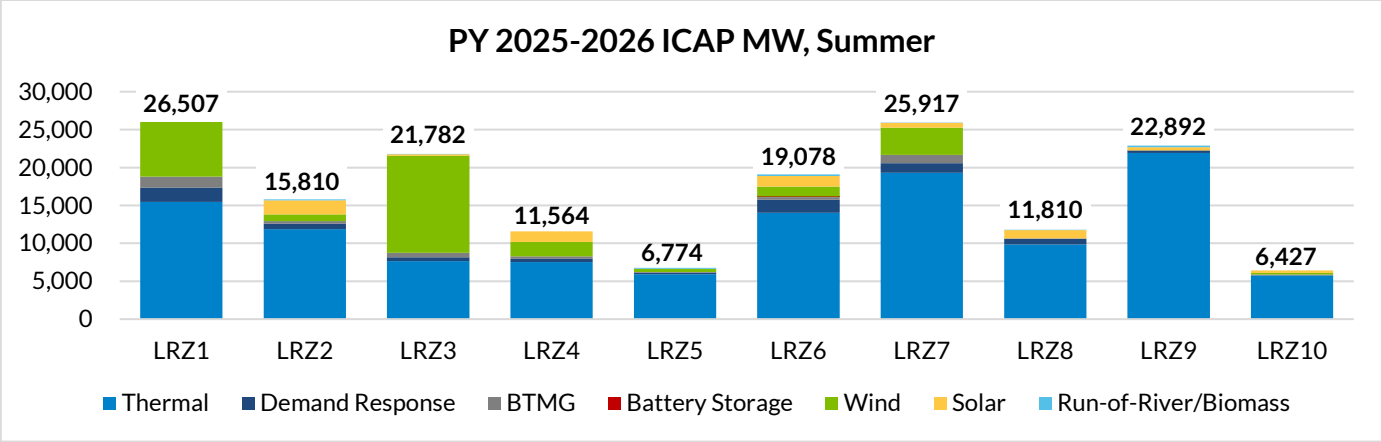


Figure 3-2: Summer Total Installed Capacity by Resource Type and Local Resource Zone

PY 2025-2026 ICAP MW, Fall											
Resource Type	**LRZ1**	**LRZ2**	**LRZ3**	**LRZ4**	**LRZ5**	**LRZ6**	**LRZ7**	**LRZ8**	**LRZ9**	**LRZ10**	**MISO**
Thermal	15,477	12,095	7,765	7,357	6,043	14,203	19,506	9,884	22,001	5,812	120,142
Demand Response	1,435	719	512	440	47	1,515	627	586	334	5	6,220
BTMG	1,235	337	591	305	96	344	1,061	13	19	103	4,103
Battery Storage	0	0	0	0	0	101	0	0	0	0	101
Wind	7,285	893	12,782	1,897	406	1,281	3,606	0	0	185	28,335
Solar	212	1,891	224	1,390	0	1,393	639	1,108	392	351	7,599
Run-of-River/Biomass	201	117	5	0	133	189	16	39	127	0	828
Total	**25,846**	**16,052**	**21,879**	**11,389**	**6,723**	**19,025**	**25,454**	**11,630**	**22,873**	**6,456**	**167,328**

Table 3-4: Fall Total Installed Capacity by Resource Type and Local Resource Zone

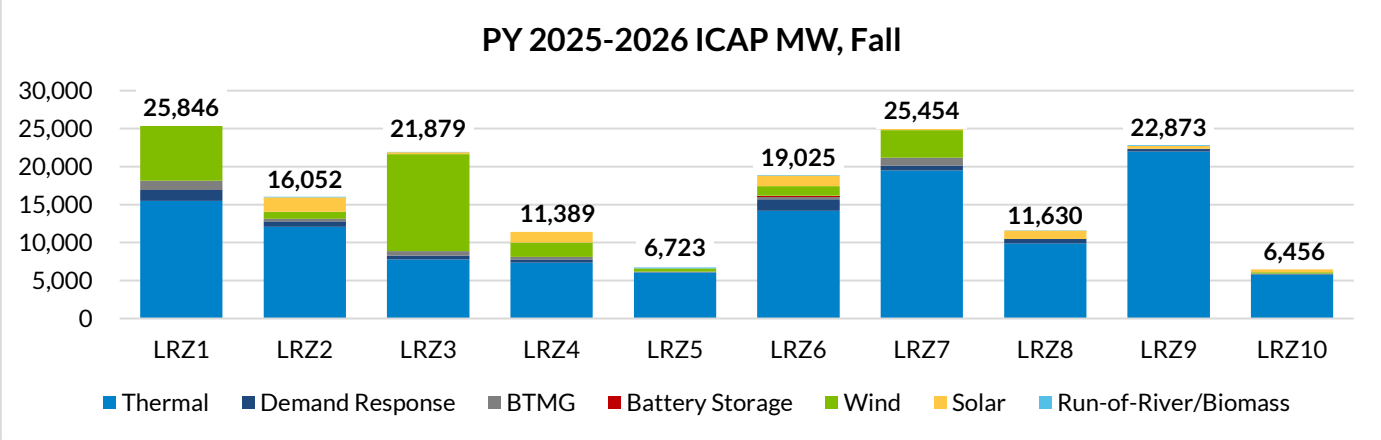


Figure 3-3: Fall Total Installed Capacity by Resource Type and Local Resource Zone

PY 2025-2026 ICAP MW, Winter											
Resource Type	**LRZ1**	**LRZ2**	**LRZ3**	**LRZ4**	**LRZ5**	**LRZ6**	**LRZ7**	**LRZ8**	**LRZ9**	**LRZ10**	**MISO**
Thermal	15,955	12,056	8,142	7,739	6,504	14,392	20,471	10,561	23,999	6,384	126,202
Demand Response	1,560	701	391	325	33	1,407	660	1,088	334	5	6,504
BTMG	756	343	616	318	92	334	1,020	17	10	103	3,609
Battery Storage	0	0	0	0	0	101	0	0	0	0	101
Wind	7,285	893	12,782	1,897	406	1,281	3,606	0	0	185	28,335
Solar	212	1,891	224	1,390	0	1,393	639	1,108	392	351	7,599
Run-of-River/Biomass	162	118	5	0	133	154	18	59	206	0	853
Total	**25,930**	**16,001**	**22,160**	**11,669**	**7,168**	**19,062**	**26,413**	**12,833**	**24,941**	**7,028**	**173,204**

Table 3-5: Winter Total Installed Capacity by Resource Type and Local Resource Zone

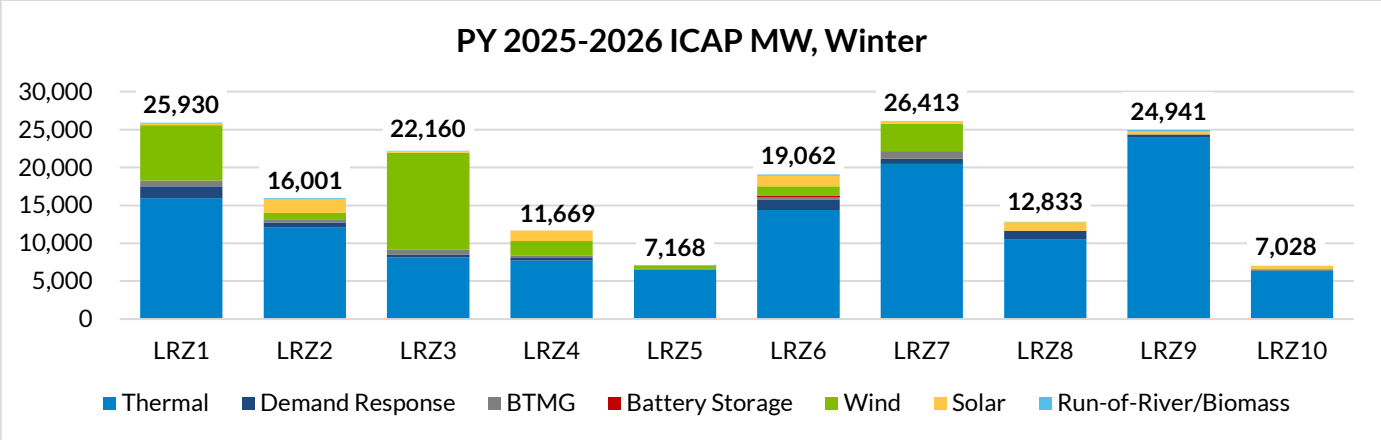


Figure 3-4: Winter Total Installed Capacity by Resource Type and Local Resource Zone

PY 2025-2026 ICAP MW, Spring											
Resource Type	**LRZ1**	**LRZ2**	**LRZ3**	**LRZ4**	**LRZ5**	**LRZ6**	**LRZ7**	**LRZ8**	**LRZ9**	**LRZ10**	**MISO**
Thermal	14,895	11,695	7,928	7,470	6,960	13,910	19,783	10,072	22,307	5,959	120,980
Demand Response	1,404	719	387	386	57	1,522	670	887	334	5	6,370
BTMG	1,390	388	619	309	95	352	1,127	27	23	104	4,433
Battery Storage	0	0	50	0	0	301	0	0	25	0	376
Wind	7,285	893	12,982	1,897	406	1,281	3,606	0	0	185	28,535
Solar	212	1,891	224	1,390	180	1,393	788	1,383	867	626	8,953
Run-of-River/Biomass	229	138	4	0	124	129	20	62	243	0	949
Total	**25,415**	**15,724**	**22,195**	**11,451**	**7,822**	**18,888**	**25,994**	**12,432**	**23,799**	**6,878**	**170,596**

Table 3-6: Spring Total Installed Capacity by Resource Type and Local Resource Zone

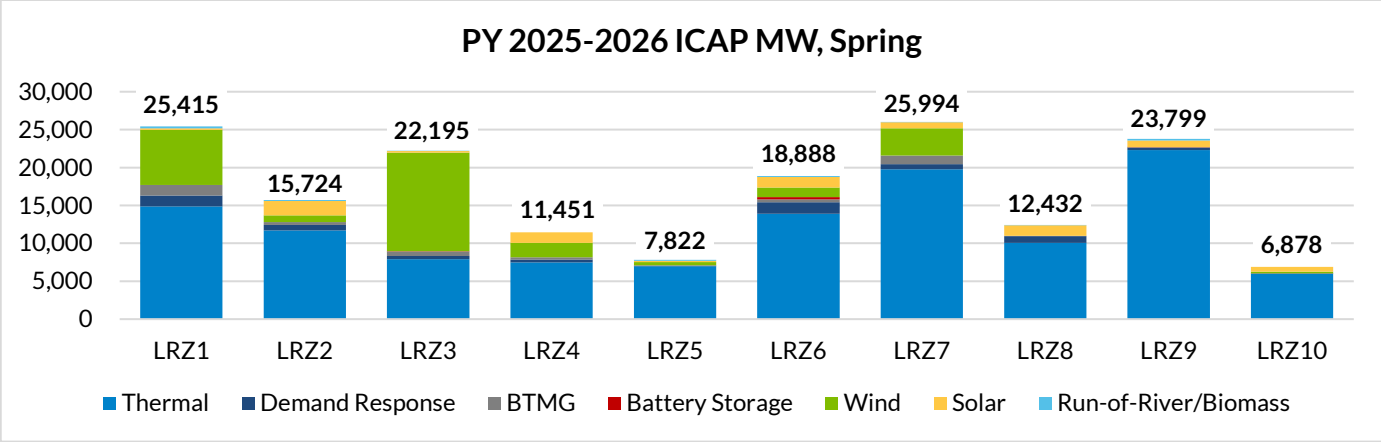


Figure 3-5: Spring Total Installed Capacity by Resource Type and Local Resource Zone

3.4 MISO Load Data

Every year, the Load Serving Entities submit new load forecasts to MISO by November 1 and, every year, MISO utilizes these load forecasts in the load development process for the LOLE study to align the load in the model with the anticipated load growth forecasted within each Local Resource Zone. At the request of stakeholders, MISO expanded its load data section to provide additional information about the LOLE study load development process.

The load development process for the Planning Year 2025-2026 LOLE analysis was enhanced through a peak correcting step regression. The regression was broadened to better account for correlations between the time of day, temperature, and load. While in the prior Planning Year 2024-2025, peak regressions factored in correlations between temperature and load without much consideration to the time of day. The Planning Year 2025-2026 LOLE analysis used a load training process pared with neural net software to establish a correlated relationship between the most recent five years of historical weather and load data. This relationship was then applied to 30 years of hourly historical load data to create 30 years of load shapes for each LRZ to capture both load diversity and seasonal variability. Zonal Coincident Peak Forecasts provided by the Load Serving Entities were used to develop zonal- and monthly-specific load forecast scaling factors which scale the average of the 30-year load shapes based on provided forecasts. The results of this process are shown as the MISO System Peak Demand (Table 1-2) and zonal Peak Demand (Table 2-1, Table 2-2, Table 2-3, and Table 2-4).

Direct Control Load Management and Interruptible Demand types of demand response were included in the LOLE model as resources. Demand response is dispatched in the LOLE model to avoid load shed during simulation when all other available generation has been exhausted.

The load development process is composed of several steps outlined in this section and will continue to be refined as needed in order to better capture weather uncertainty associated with the most recent load forecasts submitted by the Load Serving Entities.

The first step of the load development process includes data collection of the most recent year of historical hourly load data and the most recent historical temperature data from a zonal-specific weather station. This data is then consolidated with prior load and temperature data for a total historical dataset comprised of 30 years of hourly weather data and five years of hourly load data. For the PY 2025-2026 LOLE study, five years of historical data (2019 - 2023) was used in the neural net training/prediction portion of the load development process.

Data Sources:

- Historical load data is collected from MISO Resource Assessment in compliance with NERC standard MOD-032-2 requirements.
- Weather data is collected through the National Oceanic and Atmospheric Administration (NOAA) and collected from the following weather stations for each zone.

LRZ	Station	Name	State	Latitude	Longitude	Elevation
1	72658014922	MINNEAPOLIS ST. PAUL INTERNATIONAL AIRPORT, MN US	Minnesota	44.89	-93.23	254.5
2	72640014839	MILWAUKEE MITCHELL AIRPORT, WI US	Wisconsin	42.95	-87.90	203.3
3	72546014933	DES MOINES INTERNATIONAL AIRPORT, IA US	Iowa	41.53	-93.65	286.3
4	72439093822	SPRINGFIELD ABRAHAM LINCOLN CAPITAL AIRPORT, IL US	Illinois	39.85	-89.68	176.7
5	72434013994	ST LOUIS LAMBERT INTERNATIONAL AIRPORT, MO US	Missouri	38.75	-90.37	162
6	72438093819	INDIANAPOLIS INTERNATIONAL AIRPORT, IN US	Indiana	39.73	-86.28	241.3
7	72539014836	LANSING CAPITAL CITY AIRPORT, MI US	Michigan	42.78	-84.60	261.2
8	72340313963	LITTLE ROCK AIRPORT ADAMS FIELD, AR US	Arkansas	34.73	-92.24	76.4
9	72231012916	NEW ORLEANS AIRPORT, LA US	Louisiana	30.00	-90.28	-1
10	72235003940	JACKSON INTERNATIONAL AIRPORT, MS US	Mississippi	32.32	-90.08	90.2

Table 3-7: Local Resource Zone Weather Stations

The second step of the process is to normalize the five years of load data to consistent economics. Each zone is analyzed and isolated to remove economic impacts on load to ensure that load levels at different temperatures provide an appropriate range across the most recent five years of historical data. This process involves zonal load growth adjustments by comparing the most recent five years of historical load at extreme temperatures and shifting the shapes up or down if they do not reasonably overlay on top of each other. A regression analysis is then performed at the zonal level, focusing on Summer, Winter, and off-peak periods in order to compensate for the fact that the neural net training software can occasionally over- or under-predict results for extremely high or extremely low temperatures.

The third step of the process utilizes neural net software to establish functional relationships between the most recent five years of historical weather and load data. The NeuroShell Predictor software performs neural net training and predicting using a genetic algorithm. Since temperature data is not a direct input into the SERVM model, the relationships and effects it has on the MISO system are included in the 30-year hourly load shapes.

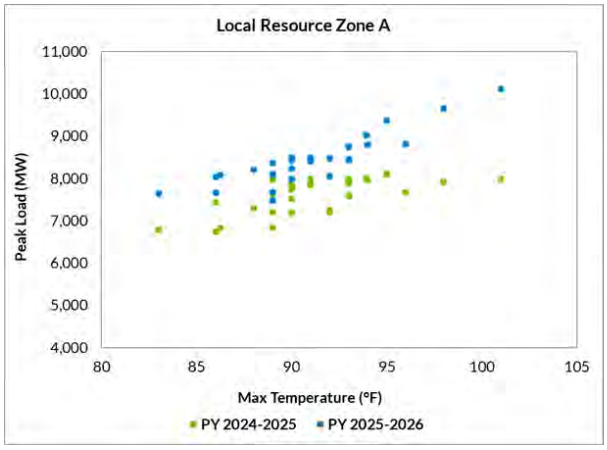
During the temperature and load training portion of this process, MISO evaluated each of the 10 LRZs by the following seasonal groupings: Summer, Winter, and off-season. Starting in the PY 2025-2026 LOLE study, the off-season grouping included both the Fall and Spring seasons. This was done to ensure there were enough extreme temperature data points and account for a larger sampling of temperature and load variability when the neural net predicts future load uncertainty. This process change resulted in an improved correlation between historical temperature and load data for the Fall and Spring seasons. The peak load and intra-hour load predictions drove some general load increases in these seasons during periods of extreme temperatures.

The graphs in Figure 3-6 below show how load responds to higher observed temperatures for months within the Fall and Spring seasons.

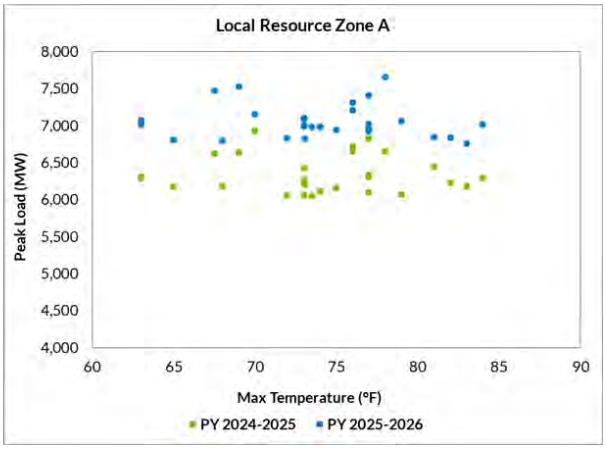
Comparable to off-season periods, the neural net software established functional relationships between historical temperature and load for the Summer and Winter seasons. However, unlike the off-season periods, the correlations between temperature and load for Summer and Winter seasons remained stable in the PY 2025-2026 LOLE study. When comparing the current Planning Year to the prior, no major outliers or concerns were identified in these correlations, and both years showed a general trend of increases in load at extreme temperatures.

The graphs in Figure 3-7 below show how load responds to higher observed temperatures for months within the Summer and Winter seasons.

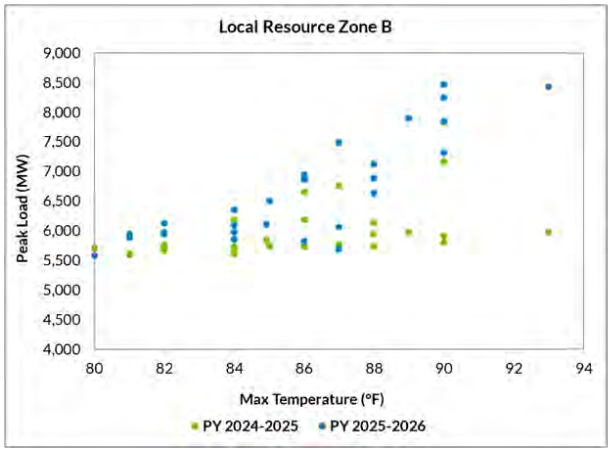
Fall Season
Temperature and Load Correlation
September



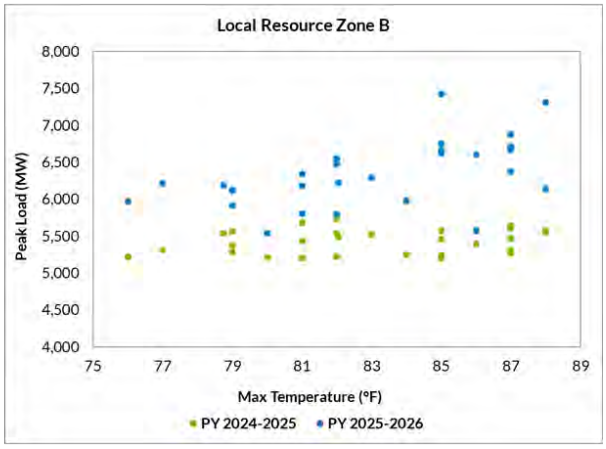
Spring Season
Temperature and Load Correlation
March



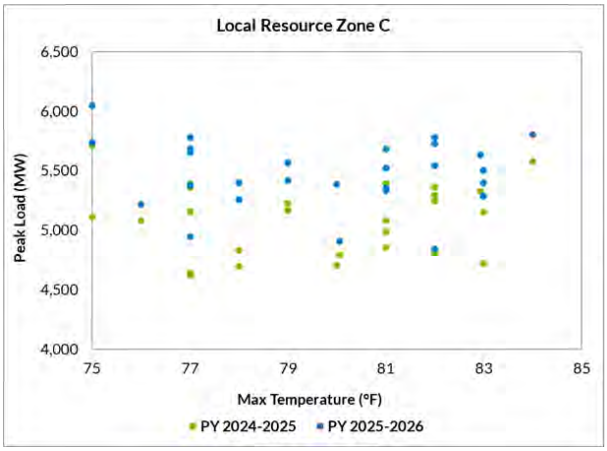
October



April



November



May

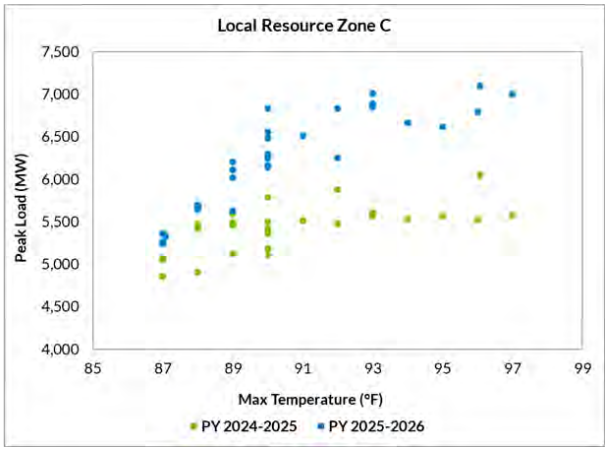
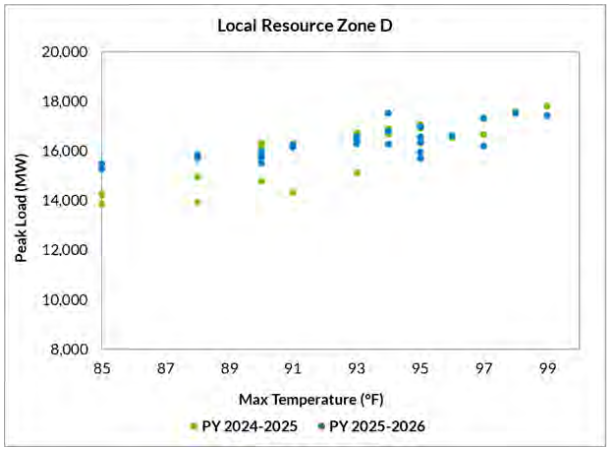
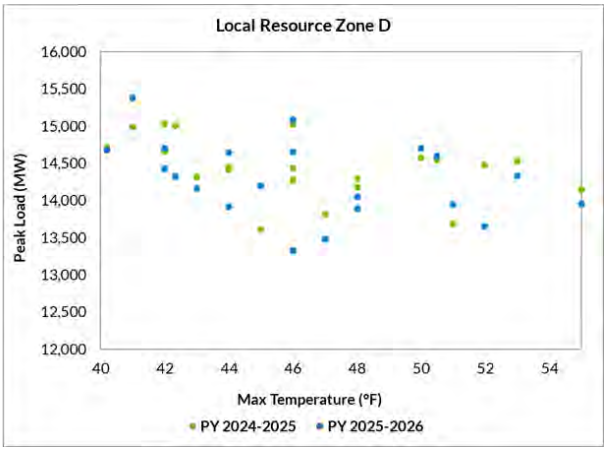


Figure 3-6: Temperature and Load Correlation for Fall and Spring Months

Summer Season
Temperature and Load Correlation
June



Winter Season
Temperature and Load Correlation
December



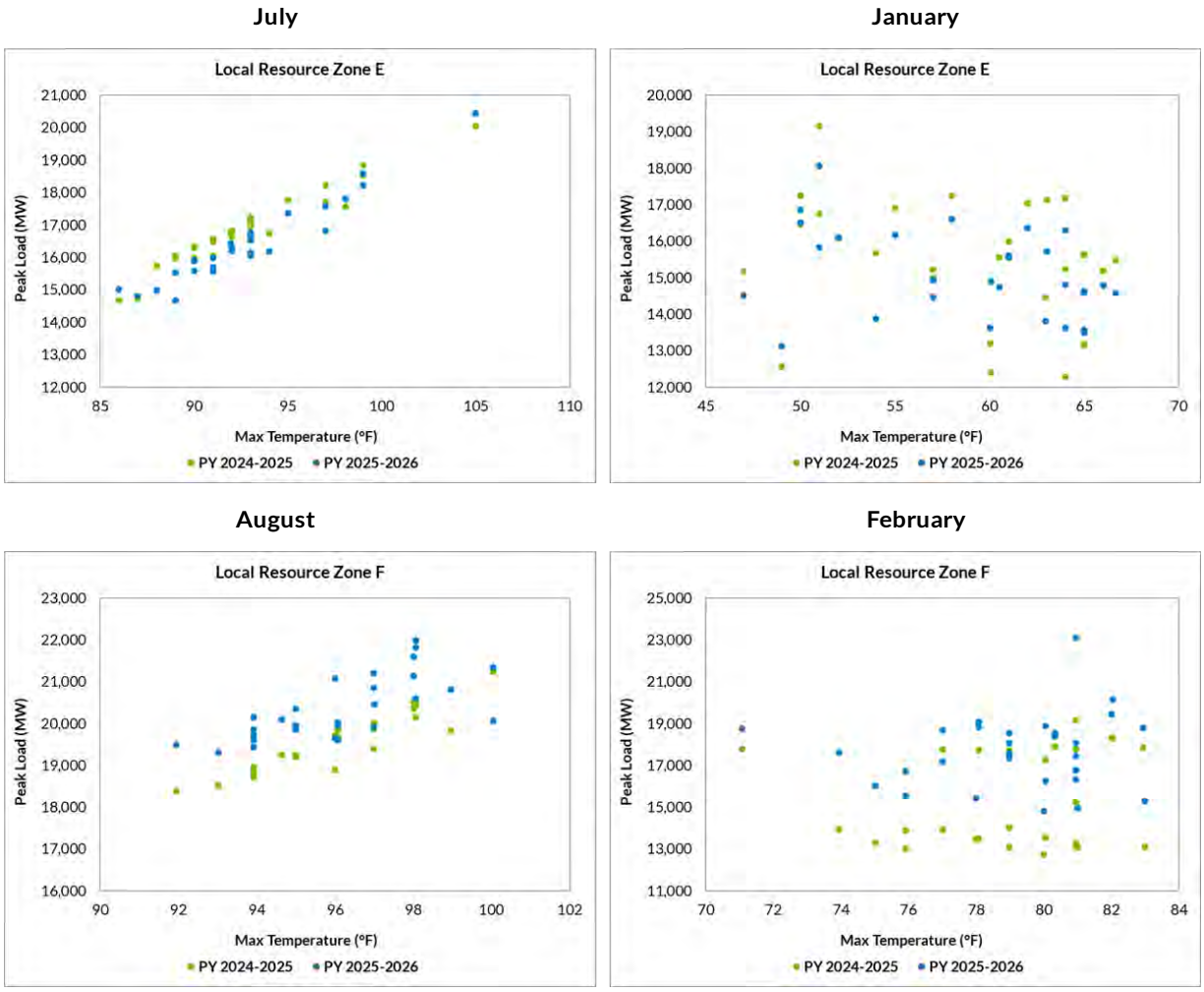


Figure 3-7: Temperature and Load Correlation for Summer and Winter Months

In the fourth step of the process and after the neural net has finished, MISO will validate the results of the neural net at extreme temperatures to smooth out any over- or under-predicted loads by comparing it against the entire 30 years of historical correlated load and weather data. During this step of the process, MISO will create a regression for the most extreme high and low temperatures in each zone to forecast out to temperatures in the 30-year range that the neural net may not have seen in the trained five-year historical load and temperature dataset.

In the fifth step of the load training process, MISO conducts a comparison of the synthetic 30-year hourly load shapes developed through the prior steps and the historical five years of hourly load data collected in the beginning of this process. During this comparative effort, MISO expects to see that the synthetic shapes are relatively in line with the historical shapes, but they should be slightly higher to account for any load reductions that were included in the historical net load shapes. If the resulting shapes are not in line with expectations, MISO will revisit step four and make any necessary changes in the regression during extreme temperatures. This may include reducing or increasing the number of data points to represent a more discrete trend.

The sixth and final step of the load training process is to average the monthly peak loads of the 30 years of predicted load shapes and adjust the load dataset to match each LRZ's total monthly zonal Coincident Peak Demand forecast

provided by the Load Serving Entities for each of the study years. To calculate the total monthly zonal Coincident Peak Demand forecasts for each year of study, the ratio of the monthly zonal Coincident Peak Demand forecast to the prompt seasonal Non-Coincident Peak Demand forecast is applied to the prompt and outyear seasonal Non-Coincident Peak Demand forecasts.

By adopting this methodology for capturing weather uncertainty, MISO can model multiple load shapes based on a functional relationship with weather. This modeling approach provides diversity in the load shapes, as well as in the peak loads observed within each zonal load shape. This approach also provides the ability to capture the frequency and duration of historical severe weather patterns.

3.4.1 Economic Load Uncertainty

To account for economic load uncertainty in the LOLE model, MISO utilized a normal distribution of electric utility forecast error accounting for projected and actual Gross Domestic Product (GDP), as well as electricity usage. The historic projections for GDP growth were taken from the Congressional Budget Office (CBO), the actual GDP growth was taken from the Bureau of Economic Analysis (BEA), and the electricity usage was taken from the U.S. Energy Information Administration (EIA). Due to a lack of state-wide projected GDP data, MISO relied on aggregated United States data when calculating economic uncertainty.

To calculate the electric utility forecast error, MISO first calculated a comparison factor representing the forecast error of actual GDP growth and historic projections. The resulting GDP forecast error was then translated into an electric utility load growth forecast error by multiplying by the rate at which electric load grew over the course of the analysis period in comparison to projected and realized GDP. Finally, a standard deviation is calculated from the electric utility load growth forecast error and used to create a normal distribution representing the probabilities of the load forecast errors (LFE) as shown in Table 3-8.

	LFE Levels				
	-2.0%	-1.0%	0.0%	1.0%	2.0%
Standard Deviation in LFE	Probability assigned to each LFE				
0.63%	0.9%	20.5%	57.3%	20.5%	0.9%

Table 3-8: Economic Uncertainty

3.5 External System

Firm imports from external areas to MISO are modeled at the individual resource level. Each firm external resource was modeled with its Installed Capacity amount and its corresponding seasonal forced outage rates, or at the contracted capacity from its corresponding Power Purchase Agreement (PPA). These resources are only modeled within the system-wide MISO PRM analyses and are not modeled when calculating the zonal LRRs, as the determination of the Local Reliability Requirements is an island-type analysis. Border External Resources and Coordinating Owner External Resources are modeled as internal MISO units and are included in the PRM and LRR analyses. External resources included as firm imports in the LOLE study were based on the amount of capacity that was either part of a Fixed Resource Adequacy Plan (FRAP), or that offered and subsequently cleared in the Planning Year 2024-2025 Planning Resource Auction (PRA).

The LOLE analyses incorporate firm exports from MISO internal units to neighboring regions, where information was available. For units with capacity sold off-system, their monthly capacities were reduced by the megawatt amount exported. These values came from PJM's Reliability Pricing Model (RPM) as well as information on exports to other external areas taken from the Independent Market Monitor (IMM) exclusion list.

Firm exports from MISO to external areas were modeled the same as in previous years. Capacity ineligible as MISO capacity due to transactions with external areas was removed from the model. Table 3-9 shows the number of firm import and export MW values in this year's study. Based on data from the Planning Year 2024-2025 PRA, MISO remained a net firm exporter.

Contracts	Summer ICAP (MW)	Summer UCAP (MW)	Fall ICAP (MW)	Fall UCAP (MW)	Winter ICAP (MW)	Winter UCAP (MW)	Spring ICAP (MW)	Spring UCAP (MW)
Imports (MW)	1,986	1,935	2,315	2,215	2,738	2,594	2,423	2,309
Exports (MW)	1,239	1,183	1,179	1,125	1,190	1,109	1,201	1,183
Net	**748**	**752**	**1,136**	**1,091**	**1,548**	**1,486**	**1,223**	**1,126**

Table 3-9: Planning Year 2025-2026 Firm Imports and Exports

Non-firm imports in the Planning Year 2025-2026 LOLE study were modeled as a seasonal probabilistic distribution representing three-year average energy imports, net of firm imports (already accounted for at the resource level), and off-system exports from MISO's internal generation. This modeling parameter is referred to as non-firm support. The distributions were developed using historic seasonal Net Scheduled Interchange (NSI) data which accounted for imports into MISO during emergency pricing hours. Firm imports cleared in the PRA for each season were subtracted from the NSI data to isolate the non-firm import values. An additional region was included in SERVM, which contained 12,000 MW of perfect generation connected to the MISO system. A distribution of the region's export capability was modeled to the upper and lower bounds. As SERVM steps through the hourly simulation, random draws on the export limits of the external region were used to represent the amount of capacity MISO could import to meet peak demand. The probability distribution of non-firm external imports used in the LOLE model is provided in Table 3-10.

	Summer	Fall	Winter	Spring
p5	1,033	-71	-377	565
p10	1,371	561	-24	829
p25	2,413	1,485	642	1,736
p50	4,351	3,346	1,817	3,720
p75	6,073	5,111	4,242	5,383
p90	7,287	6,105	5,786	6,408
p95	7,657	6,436	6,380	6,710

Table 3-10: Non-Firm External Import Distribution During Emergency Pricing Hours (MW)

3.6 Loss of Load Expectation Analysis and Metric Calculations

Upon completion of the annual LOLE study model refresh, MISO performed probabilistic analyses to determine the seasonal Planning Reserve Margin (PRM) values for Planning Year 2025-2026, as well as the seasonal Local Reliability Requirement (LRR) values for each of the 10 Local Resource Zones. The risk metrics were derived through

probabilistic modeling of the system, first solving to the industry standard annual LOLE risk target of 1 day in 10 years, or 0.1 day per year, and then solving to the minimum seasonal LOLE criteria of 0.01 LOLE for seasons demonstrating minimal risk.

3.6.1 Seasonal LOLE Distribution

To determine the seasonal LOLE distribution that is used to calculate the PRM and LRRs, MISO followed the process described in Section 68A.2.1 of Module E-1 of the MISO Tariff. This process involves first solving the LOLE model to an annual value of 0.1, then checking the seasonal distribution of the annual LOLE of 0.1. If a season had a LOLE value of at least 0.01, then it met the minimum seasonal LOLE criteria and would be set to that LOLE. If a season had less than 0.01 LOLE, additional simulations were performed until the minimum seasonal LOLE criteria of 0.01 was met.

Example: Assume the model is solved to an annual LOLE of 0.1 with 0.05 occurring in both Summer and Winter, while Fall and Spring had LOLE values of 0.00 from this simulation. In this case, the Summer and Winter seasons would not need additional analysis since both had at least 0.01 LOLE naturally when the model was solved to an annual value of 0.1. Since Fall and Spring had 0.00 LOLE, they would be assigned the minimum seasonal LOLE criteria of 0.01, and additional LOLE simulations would be performed until the minimum seasonal LOLE criteria was met through further negative adjustments to capacity in these seasons.

The annual distribution of LOLE across the four seasons at the industry standard of 1 day in 10 years, or 0.1 day per year, determined through the Planning Year 2025-2026 LOLE study, is shown in Table 3-11. The MISO-wide seasonal LOLE distribution results from the PRM analyses, and the zonal distributions result from the LRR analyses.

Region	Summer	Fall	Winter	Spring
MISO-wide	0.10	0.01	0.01	0.01
LRZ 1	0.099	0.01	0.01	0.01
LRZ 2	0.091	0.01	0.01	0.01
LRZ 3	0.098	0.01	0.01	0.01
LRZ 4	0.01	0.01	0.10	0.01
LRZ 5	0.01	0.01	0.094	0.01
LRZ 6	0.091	0.01	0.01	0.01
LRZ 7	0.099	0.01	0.01	0.01
LRZ 8	0.01	0.01	0.093	0.01
LRZ 9	0.026	0.047	0.02	0.01
LRZ 10	0.069	0.015	0.01	0.012

Table 3-11: Planning Year 2025-2026 Seasonal LOLE Distribution

3.6.2 MISO-Wide LOLE Analysis and PRM Calculation

MISO determines the appropriate PRM for each season of the applicable Planning Year based upon probabilistic analysis of reliably serving expected demand. The probabilistic analysis will utilize a Loss of Load Expectation (LOLE) study which assumes that there are no internal transmission limitations.

To determine the PRM, the LOLE model will initially be run with no adjustments to the capacity. If the LOLE is less than the minimum seasonal LOLE criteria, a negative output unit with no outage rates will be added until the LOLE

reaches the minimum seasonal LOLE criteria. This is comparable to adding load to the model. If the LOLE is greater than the minimum seasonal LOLE criteria, proxy units based on a typical combustion turbine unit of 160 MW with class average seasonal forced outage rates will be added to the model until the LOLE reaches the minimum seasonal LOLE criteria.

MISO's annual LOLE study will calculate the seasonal PRM values based on the LOLE criteria identified in the previous section. The minimum seasonal PRM requirement will be determined using the LOLE analysis by either adding a perfectly available negative output unit or by adding proxy units until a minimum LOLE of 0.01 day per season is reached.

The formulas for the PRM values for the MISO system are:

PRM ICAP % = (Installed Capacity + Firm External Support ICAP + ICAP Adjustment to meet LOLE target – MISO Coincident Peak Demand) / MISO Coincident Peak Demand

PRM UCAP % = (Unforced Capacity + Firm External Support UCAP + UCAP Adjustment to meet LOLE target – MISO Coincident Peak Demand) / MISO Coincident Peak Demand

Where Unforced Capacity (UCAP) = Installed Capacity (ICAP) x (1 – EFORd)

3.6.3 LRZ LOLE Analysis and Local Reliability Requirement Calculation

For the Local Resource Zone analyses, each zone included only the generating units within the LRZ (including Coordinating Owner External Resources and Border External Resources) and was modeled without consideration of the benefit of the LRZ's import capability. Similar to the MISO PRM analysis, Unforced Capacity is either added or removed in each LRZ such that a LOLE of 0.1 day per year is achieved when solving for the annual target and a minimum LOLE at least 0.01 day per season when solving for the minimum seasonal LOLE criteria. The minimum amount of Unforced Capacity above each LRZ's seasonal peak demand that was required to meet the reliability criteria was used to establish each LRZ's LRR.

The Planning Year 2025-2026 seasonal LRRs were determined using the LOLE analysis by first either adding or removing capacity until the annual LOLE reaches 0.1 day per year for the LRZ. If the LOLE is less than 0.1 day per year, a perfectly available negative output unit with no outage rates was added until the LOLE reaches 0.1 day per year. If the LOLE is greater than 0.1 day per year, proxy units based on a typical combustion turbine unit of 160 MW with class average seasonal forced outage rates was added to the model until the LOLE reaches 0.1 day per year.

After solving each LRZ for to the annual LOLE target of 0.1 day per year, MISO will calculate each seasonal LRR such that the summation of seasonal LOLE across the year in each zone is 1 day in 10 years, or 0.1 day per year. A minimum seasonal LOLE criterion of 0.01 will be used to calculate the LRR in seasons with less than 0.01 LOLE risk under the annual case. The seasonal Local Reliability Requirement will be determined using the LOLE analysis by either adding a perfectly available negative output unit or by adding proxy combustion turbine units until a minimum LOLE of 0.01 day per season is reached. When needed, a fraction of the marginal proxy unit was added to achieve the exact minimum seasonal LOLE criteria for the LRZ.

LRR UCAP % = (Unforced Capacity + UCAP Adjustment to meet LOLE target – Zonal Coincident Peak Demand) / Zonal Coincident Peak Demand

4 Transfer Analysis

4.1 Calculation Methodology and Process Description

Transfer analyses determined Capacity Import Limit (CIL) and Capacity Export Limit (CEL) values for LRZs in each season for Planning Year 2025-2026. Annual adjustments are made for Border External Resources and Coordinating Owner resources to determine the ZIA and ZEA in each season. Further adjustments are made for controllable exports, which are defined as exports from MISO resources that have firm capacity commitments to non-MISO load and that may be committed and dispatched by the Transmission Provider during a declared Energy Emergency. Controllable exports are subtracted from seasonal ZIA to determine seasonal CIL values. The objective of the transfer analyses is to determine constraints caused by the transfer of capacity between zones and the associated transfer capability. Multiple factors impacted the analysis when compared to previous studies, including:

- Generation
    - Loss of baseload resources being replaced by renewable resources, which impacted generation dispatch, base flows, and transmission line loadings
    - +7 GW in net installed nameplate capacity
- Transmission
    - 700+ Transmission projects at $5B
    - Approximately 150 Transmission projects above 200 kV
- Demand
    - Approximately a 4% increase in all seasons

4.1.1 Generation Pools

To determine an LRZ's import or export limit, a transfer is modeled by ramping generation up in a source subsystem and ramping generation down in a sink subsystem. The source and sink definitions depend on the limit being tested. The LRZ studied for import limits is the sink subsystem, and the adjacent MISO LBAs are the source subsystem. The LRZ studied for export limits is the source subsystem, and the rest of MISO is the sink subsystem. These are the same in all seasons for the upcoming Planning Year.

Transfers can cause potential issues, which are addressed through study assumptions. First, an abundantly large source pool spreads the impact of the transfer widely, which can cause differences in studied zones' transfer capabilities and the identified constraints. Second, ramping up generation from remote areas could cause electrically distant constraints for any given LRZ, which should not determine a zone's limit. For example, export constraints due to dispatch of LRZ 1 generation in the northwest portion of the footprint should not limit the import capability of LRZ 10, which covers the MISO portion of Mississippi.

To address these potential issues, the transfer studies limit the source pool for the import studies to the Tier 1 and Tier 2 adjacent LBAs to the study zone. Since the generation that is ramped up in export studies are contained in the study LRZ, these issues only apply to import studies. Generation within the zone studied for an export limit is ramped up and constraints are expected to be near or in the study zone.

4.1.2 Redispatch

Limited redispatch is applied after performing transfer analyses to mitigate constraints. Redispatch ensures constraints are not caused by the base dispatch and aligns with potential actions that can be implemented for the constraint by MISO control room operators. Redispatch scenarios can be designed to address multiple constraints, as

required, and may be used for constraints that are electrically close to each other or to further optimize transfer limits for several constraints requiring only minor redispatch. The redispatch assumptions include:

- The use of no more than 10 conventional fuel plants or intermittent resources
- Redispatch limit at 2,000 MW total (1,000 MW up and 1,000 MW down)
- No adjustments to nuclear units
- No adjustments to the portions of pseudo-tied units committed to non-MISO load

4.1.3 Sensitivity

Transmission Owners in a specific zone can request that a sensitivity be included in the generation-to-generation transfer to allow for the True Transfer Limit to be identified. The sensitivity would allow excluded units to be included in the generation-to-generation transfer for a zone's CIL. Excluded units mainly include nuclear units and units not to be used in zonal transfers from the latest MTEP model. This sensitivity can only be requested for a CIL study. A sensitivity would only be accepted for a particular zone if they are in a situation like that seen in Figure 4-1 below.

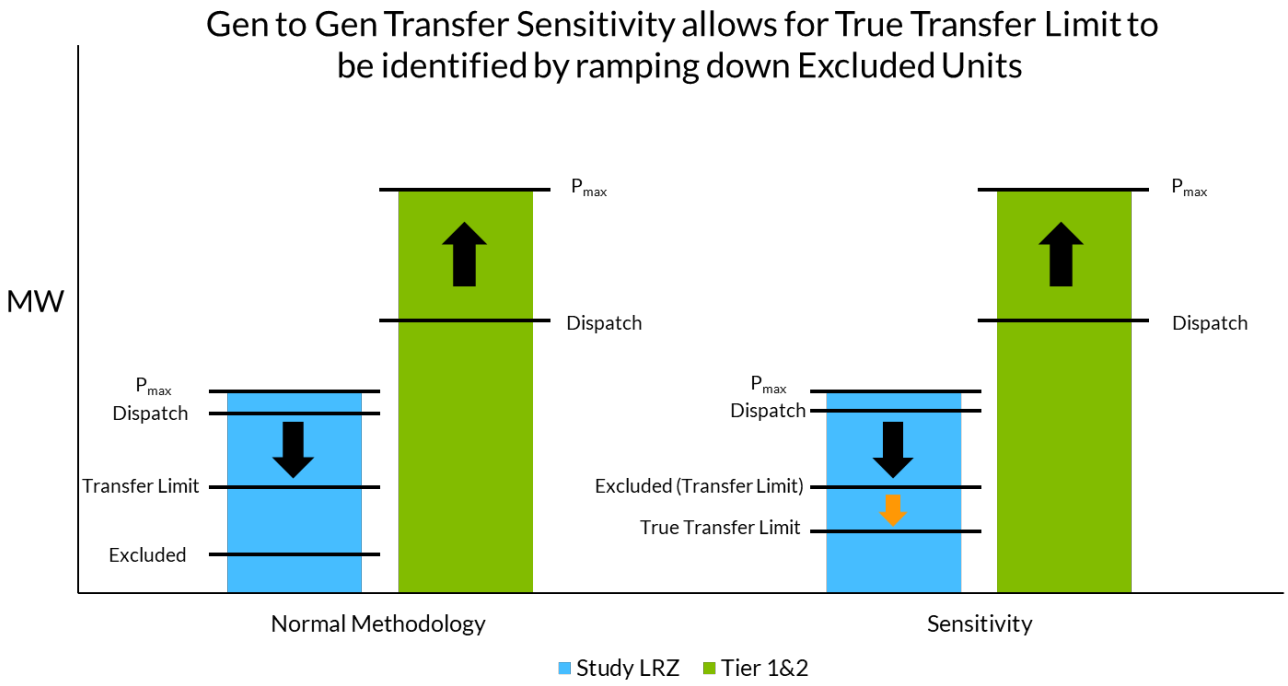


Figure 4-1: Generation-to-Generation Transfer Sensitivity

The two bars shown for the Normal Methodology category would not allow for a sensitivity to be requested by a Transmission Owner. In this situation, since the transfer limit is already identified before hitting the excluded units, a request for a generation-to-generation transfer sensitivity would not be accepted. The two bars shown for the Sensitivity category identify a situation where a request for a generation-to-generation transfer sensitivity would be accepted. When ramping down generation, the excluded units are hit before the True Transfer Limit, but since the rest of the units are excluded, the transfer limit would be identified as the point where the generation-to-generation

stops at the excluded units. With a sensitivity in place, the generation-to-generation transfer would continue into the excluded units, and the True Transfer Limit would be identified.

LRZ 10 was the only Local Resource Zone to utilize a generation-to-generation transfer sensitivity and have these results included in their Capacity Import Limit for Planning Year 2025-2026.

4.1.4 Generation Limited Transfer for CIL/CEL and ZIA/ZEA

When conducting a transfer analysis to determine import or export limits, the source subsystem might run out of generation to dispatch before identifying a valid constraint caused by a transmission limit. MISO developed a Generation Limited Transfer (GLT) process to identify transmission constraints in these situations, when possible, for both imports and exports.

After running the First Contingency Incremental Transfer Capability (FCITC) analysis to determine limits for each LRZ, MISO will determine whether a zone is experiencing a GLT (e.g., whether the first constraint would occur only after all the generation is dispatched at its maximum amount). If the LRZ experiences a GLT, MISO will adjust the base model depending on whether it is an import or export analysis and re-run the transfer analysis.

For an export study, when a transmission constraint has not been identified after all generation has been dispatched within the exporting system (LRZ under study), MISO will decrease load and generation dispatch in the study zone. The adjustment creates additional capacity to export from the zone. After the adjustments are complete, MISO will re-run the transfer analysis. If a GLT reappears, MISO will make further adjustments to the load and generation of the study zone.

For an import study, when a transmission constraint has not been identified after all generation has been dispatched within the source subsystem, MISO will decrease load and generation in the source subsystem. This increases the export capacity of the adjacent LBAs for the study zone. After the adjustments are complete, MISO will run the transfer analysis again. If a GLT reappears, MISO will make further adjustments to the model's load and generation in the source subsystem.

FCITC could indicate the transmission system can support larger thermal transfers than would be available based on installed generation for some zones—however, large variations in load and generation for any zone may lead to unreliable limits and constraints. Therefore, MISO limits load scaling for both import and export studies to 50 percent of the zone's load. In a GLT, redispatch, or GLT plus redispatch scenario, the FCITC of the most limiting constraint might exceed Zonal Export/Import Capability. If the GLT does not produce a limit for a zone, either due to a valid constraint not being identified or due to other considerations as listed in the prior paragraph, MISO shall report that LRZ as having no limit and ensure that the limit will not bind in the first iteration of the Simultaneous Feasibility Test (SFT).

4.1.5 Voltage Limited Transfer for CIL/CEL and ZIA/ZEA

Zonal imports may be limited by voltage constraints due to a decrease in the generation in the study zone. Voltage constraints might occur at lower transfer levels than thermal limits determined by linear FCITC. As such, LOLE studies may evaluate power-voltage curves for LRZs with known voltage-based transfer limitations identified through existing MISO or Transmission Owner studies. Such evaluation may also occur if an LRZ's import reaches a level where the majority of the zone's load would be served using imports from resources outside of the zone. MISO will coordinate with stakeholders as it encounters these scenarios. For Planning Year 2025-2026, only Local Resource Zones 1, 4, and 7 import analyses included voltage screening and study. No studies identified a voltage limit with lower transfer capability than the thermal limit for Planning Year 2025-2026.

4.2 Powerflow Models and Assumptions

4.2.1 Tools Used

MISO used the Siemens PTI Power System Simulator for Engineering (PSS/E) and PowerGEM Transmission Adequacy and Reliability Assessment (TARA) tools.

4.2.2 Inputs Required

Thermal transfer analysis requires Powerflow models and related input files. MISO used contingency files from MTEP[2] reliability assessment studies. Single-element contingencies in MISO and seam areas were also evaluated.

MISO developed a subsystem file to monitor its footprint and seam areas which were used for all seasons. LRZ definitions were developed as sources and sinks in the study. See Appendix A for tables containing adjacent area definitions (Tiers 1 and 2) used for this study. The monitored file includes all facilities under MISO functional control and single elements in the seam areas of 100 kV and above.

4.2.3 Powerflow Modeling

The MTEP23 models were built using MISO's Model on Demand (MOD) model data repository, with the following base assumptions (Table 4-1).

Scenario	Effective Date	Projects Applied	External Modeling	Load and Generation Profile	Wind %	Solar %
Summer 2025	July 15th	MTEP Appendix A and Target A	ERAG MMWG 2023 Series 2025 Summer Peak Load Model	Summer Peak	18%	50%
Fall 2025	October 15th	MTEP Appendix A and Target A	ERAG MMWG 2023 Series 2025 Spring Light Load Model	Fall Peak	28.5%	31%
Winter 2025-2026	January 15th	MTEP Appendix A and Target A	ERAG MMWG 2023 Series 2025 Winter Peak Load Model	Winter Peak	67%	0%
Spring 2026	April 15th	MTEP Appendix A and Target A	ERAG MMWG 2023 Series 2025 Spring Light Load Model	Spring Peak	28.5%	31%

Table 4-1: Model Assumptions

MISO excluded several types of units from the transfer analysis dispatch; these units' base dispatch remained fixed.

- Nuclear dispatch does not change for any transfer without a sensitivity
- Wind and solar resources can be ramped down, but not up
- Pseudo-tied resources were modeled at their expected commitments to non-MISO load, although portions of these units committed to MISO could participate in transfer analyses

System conditions such as load, dispatch, topology, and interchange have an impact on transfer capability. The model was reviewed as part of the base model built for MTEP24 analyses, with study files made available on MISO ShareFile. MISO worked closely with Transmission Owners and stakeholders to model the transmission system accurately, as

[2] Refer to the Transmission Planning BPM (BPM-20) for more information regarding MTEP input files. https://www.misoenergy.org/legal/business-practice-manuals/

well as to validate constraints and redispatch. Like other planning studies, transmission outage schedules were not included in the analyses. This is driven partly by limited availability of outage information as well as current transmission planning standards. Although no outage schedules were evaluated, single-element contingencies were evaluated. This includes Bulk Electric System lines, transformers, and generators.

Contingency coverage covers most of category P1 and some of category P2 outlined in Table 1 of NERC Reliability Standard TPL-001.

4.2.4 General Assumptions

MISO uses TARA to process the Powerflow model and associated input files to determine the seasonal import and export limits of each LRZ by determining the transfer capability. Transfer capability measures the ability of interconnected power systems to reliably transfer power from one area to another under specified system conditions. The incremental amount of power that can be transferred is determined through FCITC analysis. FCITC analysis and base power transfers provide the information required to calculate the First Contingency Total Transfer Capability (FCTTC), which indicates the total amount of transferable power before a constraint is identified. FCTTC is the base power transfer plus the incremental transfer capability (Equation 4-1). All published limits are based on the zone's FCTTC and may be adjusted for capacity exports.

$$First\ Contingency\ Total\ Transfer\ Capability\ (FCTTC) = Base\ Power\ Transfer + FCITC$$

Equation 4-1: Total Transfer Capability

FCITC constraints are identified under base case situations in each season or under P1 contingencies provided through the MTEP process. Linear FCITC analysis identifies the limiting constraints using a minimum transfer Distribution Factor (DF) cutoff of three percent, meaning the transfer must increase the loading on the overloaded element, under system intact or contingency conditions, by three percent or more.

A pro-rata dispatch is used, which ensures all available generators will reach their maximum dispatch level at the same time. The pro-rata dispatch is based on the MW reserve available for each unit and the cumulative MW reserve available in the subsystem. The MW reserve is found by subtracting a unit's base model generation dispatch from its maximum dispatch, which reflects the available capacity of the unit.

Table 4-2 and Equation 4-2 show an example of how one unit's dispatch is set, given all machine data for the source subsystem.

Machine	Base Model Unit Dispatch (MW)	Minimum Unit Dispatch (MW)	Maximum Unit Dispatch (MW)	Reserve MW (Unit Dispatch Max – Unit Dispatch Min)
1	20	20	100	80
2	50	10	150	100
3	20	20	100	80
4	450	0	500	50
5	500	100	500	0
			Total Reserve	**310**

Table 4-2: Example Subsystem

$$\boldsymbol{Machine\ 1\ Incremental\ Post\ Transfer\ Dispatch} = \frac{\boldsymbol{Machine\ 1\ Reserve\ MW}}{\boldsymbol{Source\ Subsystem\ Reserve\ MW}} \times \boldsymbol{Transfer\ Level\ MW}$$

$$Machine\ 1\ Incremental\ Post\ Transfer\ Dispatch = \frac{80}{310} \times 100 = 25.8$$

$$Machine\ 1\ Incremental\ Post\ Transfer\ Dispatch = 25.8$$

Equation 4-2: Machine 1 Dispatch Calculation for 100 MW Transfer

4.3 Results for CIL/CEL and ZIA/ZEA

Study constraints and associated ZIA, ZEA, CIL, and CEL for each LRZ for each season were presented and reviewed through the LOLEWG with final results for Planning Year 2025-2026 presented at the October 24th, 2024 meeting. Table 4-3 below shows the Planning Year 2025-2026 CIL and ZIA with corresponding constraint, GLT, and redispatch (RDS) information.

All zones had an identified ZIA this year. If there is no valid constraint identified, the following equation will be used where the FCITC will be replaced by the Tier 1 and Tier 2 capacity.

$$\boldsymbol{ZIA} = \boldsymbol{FCITC} + \boldsymbol{Area\ Interchange} - \boldsymbol{Border\ External\ Resources\ and\ Coordinating\ Owners}$$

Equation 4-3: Zonal Import Ability (ZIA) Calculation

LRZ1	Monitored Element	Contingency	GLT	RDS	ZIA	CIL
Summer 2025	North Appleton - Werner West 345 kV	North Appleton - Morgan 345 kV	10%	460MWx2	6023	6025
Fall 2025	Stone Lake 345/161 kV Transformer	Arrowhead 345/230 kV Transformer	None	515MWx2	5688	5690
Winter 2025-26	Laurel - Jasper 161 kV	Story County - Fernald 161 kV	None	601MWx2	5573	5575
Spring 2026	Mound City - Bismark 230 kV	Ft Thompson 1 - Chapelle 345 kV	None	352MWx2	6396	6398
LRZ2	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2025	Two Harbors - Silver Bay 115 kV	Taconite Harbor - LTV Hoyt Lakes 115 kV	None	439MWx2	4370	4370
Fall 2025	Zion - Pleasant Prairie 345 kV	Zion EC - Pleasant Prairie 345 kV	None	666MWx2	6537	6537
Winter 2025-26	Nelson Dewey 161/138 kV Transformer	Hickory Creek - Hill Valley 345 kV	None	1000MWx2	6435	6435
Spring 2026	Zion EC - Pleasant Prairie 345 kV	Zion - Pleasant Prairie 345 kV	None	624MWx2	6439	6439
LRZ3	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2025	Sub 3458 (Nebraska City) - Sub 3456 345 kV	Sub 3455 - Sub 3740 345 kV	None	302MWx2	5460	5518
Fall 2025	Sub 1211 - Sub 701 161 kV	Sub 3456 - Council Bluffs 345 kV	None	177MWx2	7704	7766
Winter 2025-26	Split Rock 7 - Split Rock 4 115 kV	Split Rock 3 - Sioux City 345 kV	None	1000MWx2	5785	5853
Spring 2026	Sub 1211 - Sub 701 161 kV	Sub 3456 - Council Bluffs 345 kV	None	138MWx2	7726	7784
LRZ4	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2025	Kincaid - Austin 345 kV	Lincoln Land Generator	5%	247MWx2	7757	8649
Fall 2025	Palmyra - Marblehead North 161 kV	Herleman - Palmyra Tap 345 kV	25%	880MWx2	7013	7908
Winter 2025-26	Sandburg 161/138 kV Transformer	Galesburg - Oak Grove 345 kV	None	1000MWx2	6457	7353
Spring 2026	Palmyra - Marblehead North 161 kV	Herleman - Palmyra Tap 345 kV	25%	866MWx2	7373	8272
LRZ5	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2025	Rezzy - Moro 138 kV	Redhawk - Moro 345 kV	None	697MWx2	4117	4117
Fall 2025	Rezzy - Moro 138 kV	Redhawk - Moro 345 kV	25%	608MWx2	4679	4679
Winter 2025-26	Hannibal West - Spalding 161 kV	Palmyra - Spencer Creek 345 kV	None	1000MWx2	4922	4922
Spring 2026	Mississippi Tap - Sioux 138 kV	Sioux Generator	10%	217MWx2	4453	4453
LRZ6	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2025	Cayuga - Nucor 345 kV	Dresser - Sugar Creek 345 kV	10%	571MWx2	8366	8650
Fall 2025	Cayuga - Cayuga Sub 345 kV	Kansas West - Sugar Creek 345 kV	None	162MWx2	8672	8970
Winter 2025-26	Kokomo Highland Park - Tipton 230 kV	Cayuga - Nucor 345 kV	None	1000MWx2	7690	7936
Spring 2026	Eugene - Cayuga Sub 345 kV	Kansas West - Sugar Creek 345 kV	None	431MWx2	9176	9491
LRZ7	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2025	Amo - Qualitech Steel 345 kV	Gibson - Wheatland 345 kV	None	1000MWx2	3569	3579
Fall 2025	Benton Harbor - Segreto 345 kV	Cook - Segreto 345 kV	None	1000MWx2	5115	5125
Winter 2025-26	Benton Harbor - Segreto 345 kV	Cook - Segreto 345 kV	None	1000MWx2	4762	4762
Spring 2026	Benton Harbor - Segreto 345 kV	Cook - Segreto 345 kV	None	643MWx2	5166	5166
LRZ8	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2025	J620 - Dermott 115 kV	Lake Village Bagby - Reed SS 115 kV	None	697MWx2	2358	2522
Fall 2025	Mount Olive - Vienna 115 kV	Mount Olive - Eldorado 500 kV	None	1000MWx2	5675	5870
Winter 2025-26	Clarksdale - Lyon 115 kV	Moon Lake - Clarkesdale 230 kV	None	1000MWx2	3432	3534
Spring 2026	Mount Olive - Vienna 115 kV	Mount Olive - Eldorado 500 kV	None	1000MWx2	6085	6250
LRZ9	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2025	Sterlington - Downsville 115 kV	Mount Olive - Eldorado 500 kV	None	1000MWx2	4361	4872
Fall 2025	Danville - Dodson 115 kV	Mount Olive - Layfield 500 kV	None	1000MWx2	4741	5242
Winter 2025-26	Arklahoma - Hot Springs East 115 kV	Arklahoma - Hot Springs West 115 kV	None	1000MWx2	4418	4995
Spring 2026	Daniel - Daniel Intermediate 1 230 kV	Daniel - Daniel Intermediate 2 230 kV	None	1000MWx2	4855	5370
LRZ 10	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZIA**	**CIL**
Summer 2025	Ritchie - Moon Lake 230 kV	Perryville - Baxter Wilson 500 kV	None	1000MWx2	4474	4474
Fall 2025	Ritchie - Moon Lake 230 kV	Perryville - Baxter Wilson 500 kV	None	602MWx2	4508	4508
Winter 2025-26	Little Gypsy - Fairview 230 kV	Michoud - Front Street 230 kV	None	1000MWx2	3458	3458
Spring 2026	Perryville - Baxter Wilson 500 kV	Grand Gulf Generator	None	1000MWx2	4365	4365

Table 4-3: Planning Year 2025–2026 Import Limits

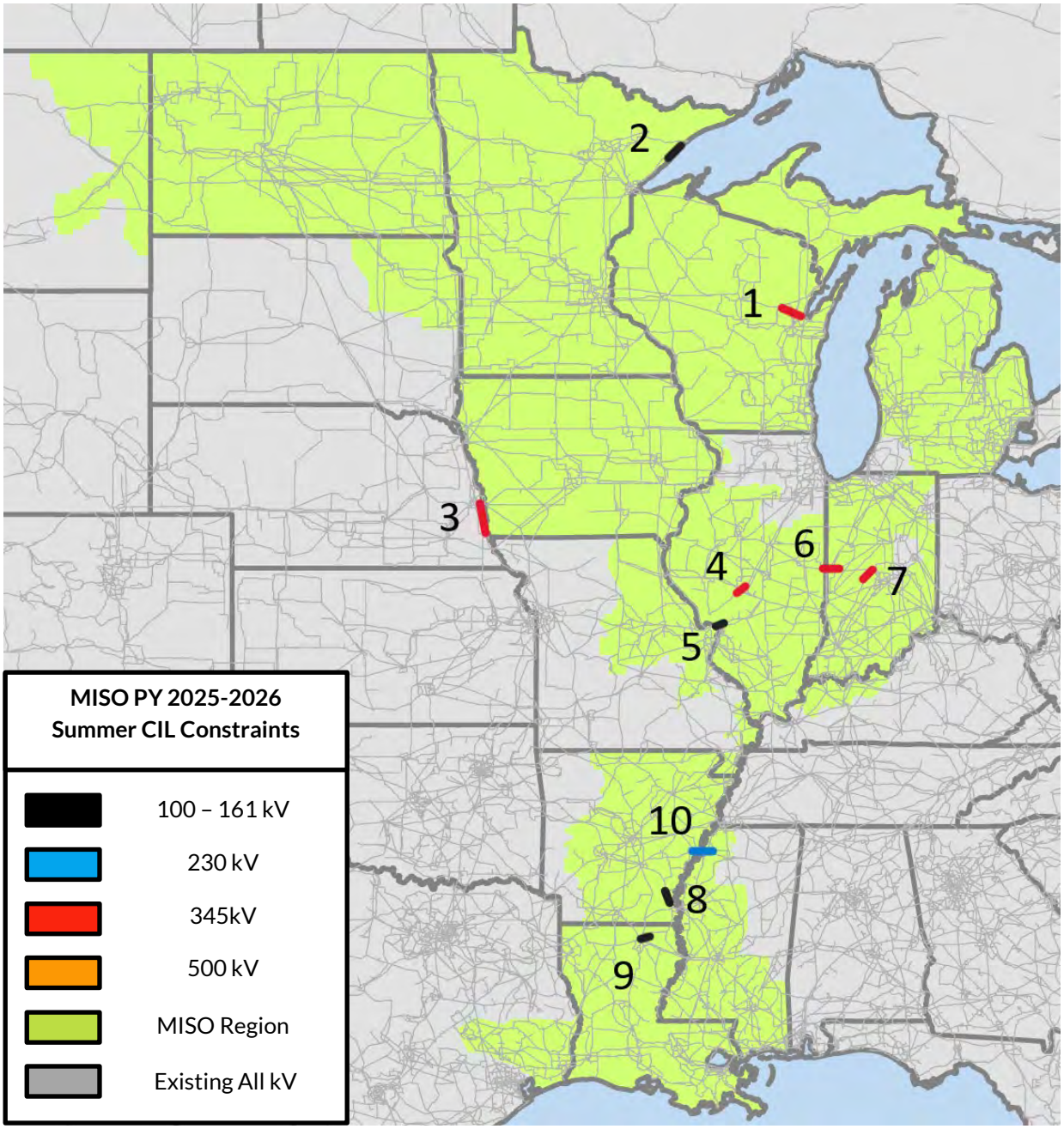


Figure 4-2: Planning Year 2025-2026 Summer Capacity Import Constraints Map

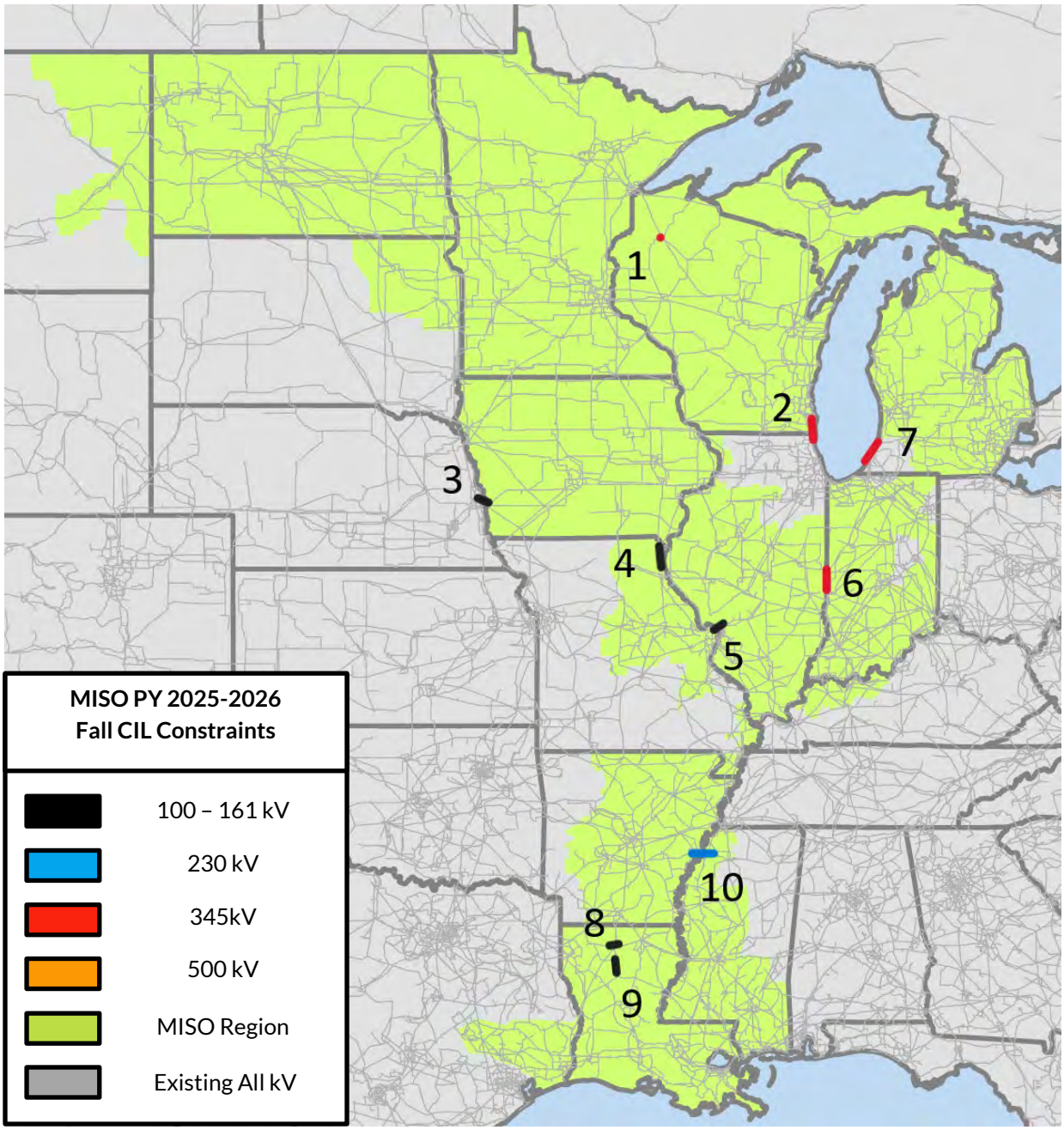


Figure 4-3: Planning Year 2025-2026 Fall Capacity Import Constraints Map

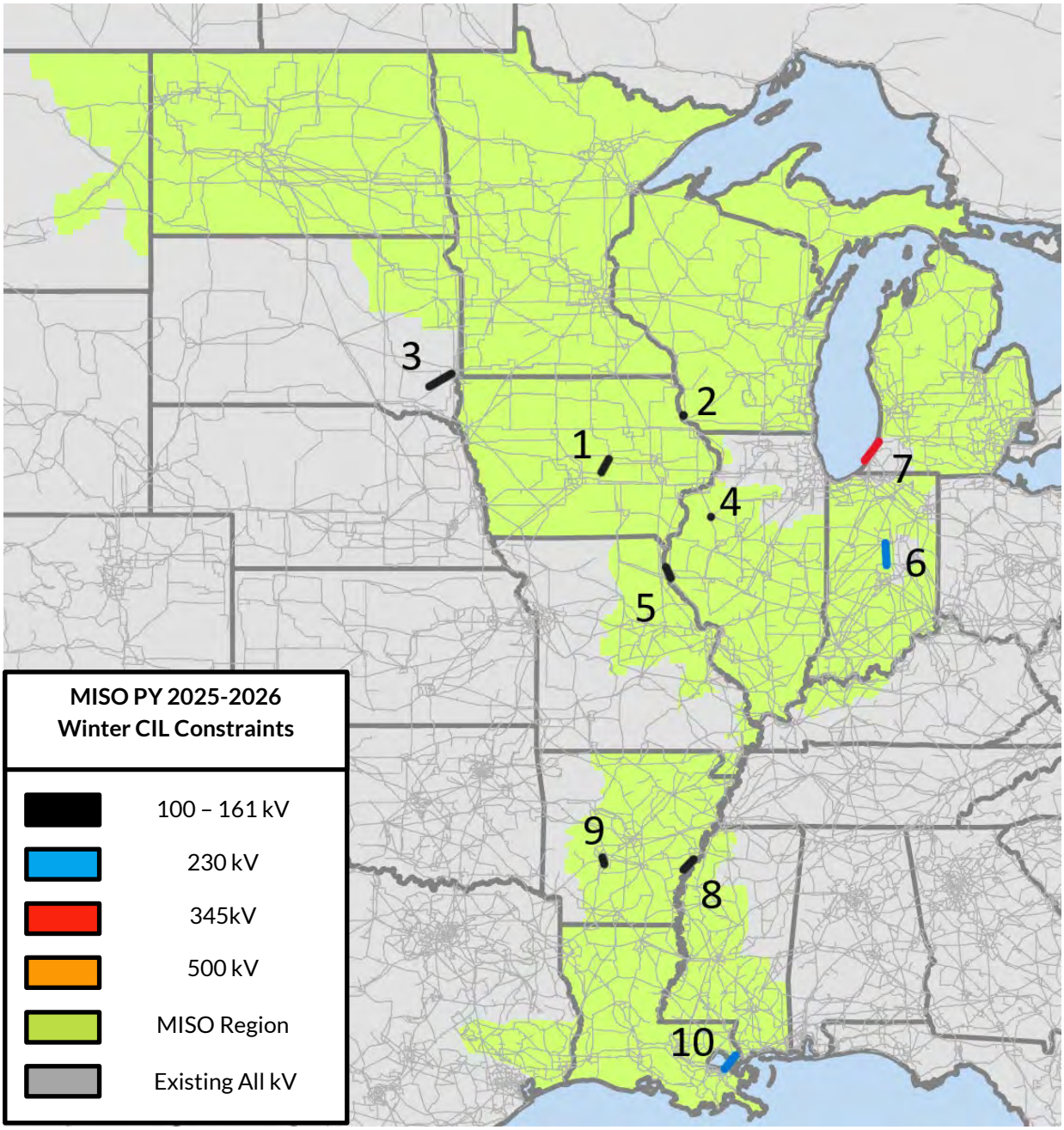


Figure 4-4: Planning Year 2025-2026 Winter Capacity Import Constraints Map

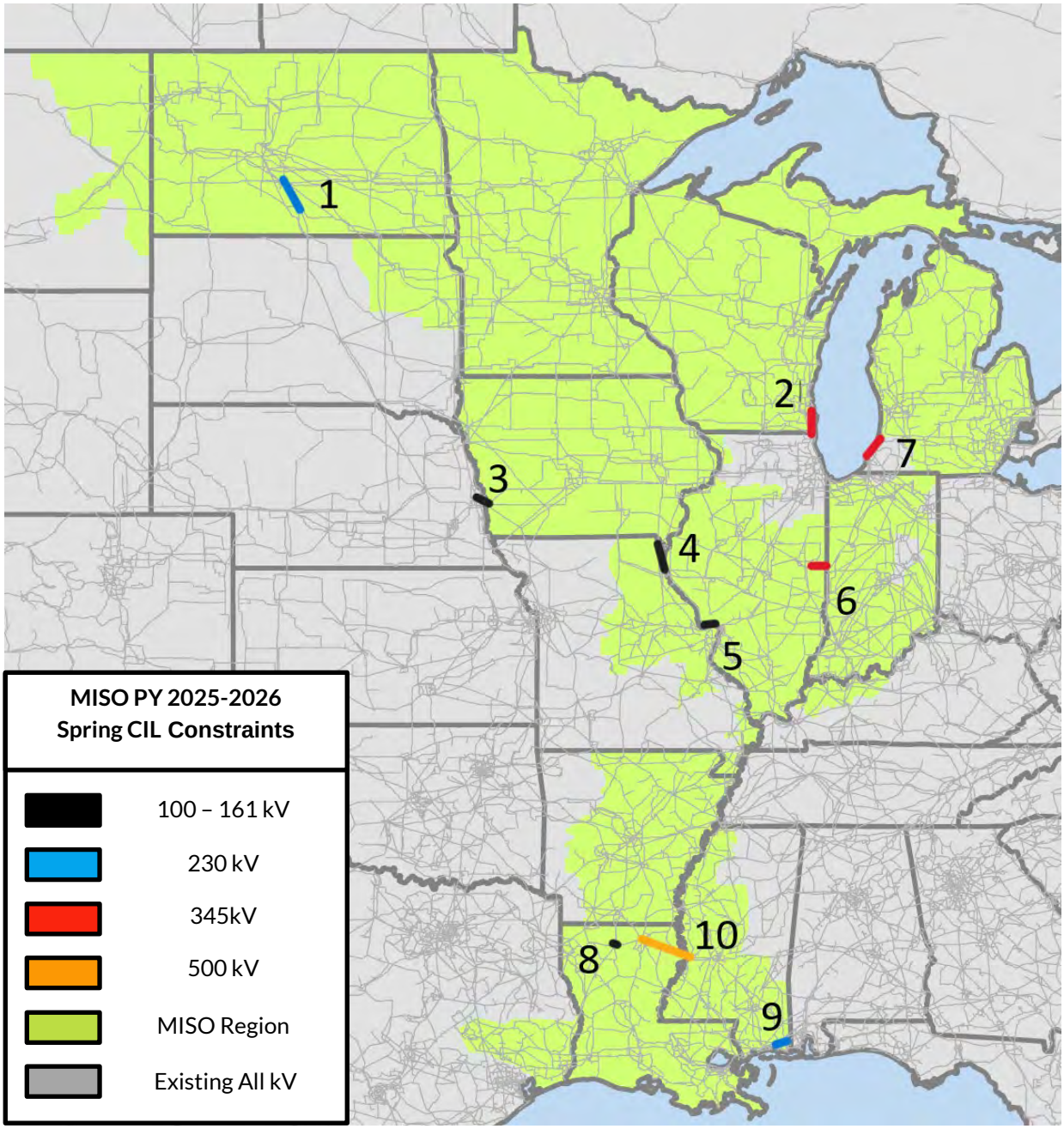


Figure 4-5: Planning Year 2025-2026 Spring Capacity Import Constraints Map

Capacity Exports Limits are found by increasing generation in the study zone and decreasing generation in the rest of the MISO footprint to create a transfer. Table 4-4 below shows the Planning Year 2025-2026 CEL and ZEA with corresponding constraint, GLT, and redispatch information.

LRZ1	Monitored Element	Contingency	GLT	RDS	ZEA	CEL
Summer 2025	Split Rock 4 - Sioux Falls 230 kV	Split Rock 3 - Sioux City 345 kV	None	293MWx2	3993	3991
Fall 2025	Adams - Mitchell County 345 kV	Disconnect Blackhawk Reactor	None	270MWx2	6167	6165
Winter 2025-26	Split Rock 7 - Split Rock 4 115 kV	Split Rock - Sioux City 345 kV	None	721MWx2	3593	3591
Spring 2026	Adams - Mitchell County 345 kV	Disconnect Blackhawk Reactor	None	279MWx2	5285	5283
LRZ2	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2025	Neevin - Butte Des Morts 138 kV	Neevin-Woodenshoe 138 kV	25%	633MWx2	4614	4614
Fall 2025	Sherman Street - Sunnyvale 115 kV	Arpin - Rocky Run 345 kV	10%	909MWx2	4259	4259
Winter 2025-26	Granville - Butler 138 kV	Arcadian-Granville 345 kV	20%	561MWx2	4793	4793
Spring 2026	Berryville - Paris 138 kV	Paris 345/138 kV Transformer	30%	674MWx2	6119	6119
LRZ3	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2025	No Limiting Element	None	50%	None	4713	4655
Fall 2025	No Limiting Element	None	50%	None	5924	5862
Winter 2025-26	Council Bluffs - Sub 3456 345 kV	Arbor Hill - Raccoon Trail 345 kV	None	561MWx2	7480	7412
Spring 2026	No Limiting Element	None	50%	None	6039	5981
LRZ4	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2025	Alsey - Winchester 138 kV	Alsey - Ballard 138 kV	40%	577MWx2	5352	4460
Fall 2025	Marion - Marion South 161 kV	Silver Mine Substation	None	1000MWx2	5069	4174
Winter 2025-26	No Limiting Element	None	50%	None	5531	4635
Spring 2026	Marion - Marion South 161 kV	Silver Mine Substation	None	212MWx2	5880	4981
LRZ5	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2025	No Limiting Element	None	45%	None	3939	3939
Fall 2025	No Limiting Element	None	50%	None	5816	5816
Winter 2025-26	No Limiting Element	None	50%	None	4814	4814
Spring 2026	No Limiting Element	None	50%	None	5797	5797
LRZ6	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2025	Gibson - Douglas 345 kV	AB Brown - Posey East 345 kV	40%	70MWx2	7165	6881
Fall 2025	AEP Rockport - Grandview 138 kV	AB Brown - Reid 345 kV	None	539MWx2	5471	5173
Winter 2025-26	AB Brown - AB Brown Reactor 138 kV	AB Brown - Reid 345 kV	None	518MWx2	1911	1665
Spring 2026	Holland - Dubois 138 kV	Duff - Francisco 345 kV	None	487MWx2	6706	6391
LRZ7	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2025	Monroe - Lallendorf 345 kV	Morocco - Allen Junction 345 kV	15%	1000MWx2	5726	5716
Fall 2025	Monroe - Lallendorf 345 kV	Morocco - Allen Junction 345 kV	None	1000MWx2	5168	5158
Winter 2025-26	Morocco - Allen Junction 345 kV	Monroe - Lallendorf 345 kV	None	1000MWx2	5712	5712
Spring 2026	Monroe - Lallendorf 345 kV	Morocco - Allen Junction 345 kV	None	1000MWx2	5499	5499
LRZ8	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2025	No Limiting Element	None	50%	641MWx2	6509	6345
Fall 2025	Cash - Jonesboro 161 kV	Independence - Power Line Road 500 kV	None	1000MWx2	4219	4024
Winter 2025-26	Freeport - Cordova 500 kV	Sans Souci - Driver 500 kV	20%	422MWx2	3783	3681
Spring 2026	Freeport - Cordova 500 kV	Sans Souci - Driver 500 kV	None	382MWx2	3724	3559
LRZ9	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2025	Montgomery - Clarence 230 kV	Montgomery - Winfield 230 kV	None	1000MWx2	4286	3775
Fall 2025	Ray Braswell - Northside Drive 230 kV	Ray Braswell - Lakeover 500 kV	None	1000MWx2	4173	3672
Winter 2025-26	Little Gypsey - Fairview 230 kV	Michoud - Front Street 230 kV	None	1000MWx2	3618	3041
Spring 2026	Ray Braswell - Northside Drive 230 kV	Ray Braswell - Lakeover 500 kV	None	1000MWx2	4146	3631
LRZ10	**Monitored Element**	**Contingency**	**GLT**	**RDS**	**ZEA**	**CEL**
Summer 2025	Batesville - Tallahatchie 161 kV	Batesville - East Batesville 161 kV	None	710MWx2	2097	2097
Fall 2025	Lake Village Bagby - Macon Lake 115 kV	Lake Village Bagby - Reed 115 kV	None	650MWx2	3164	3164
Winter 2025-26	Batesville - Tallahatchie 161 kV	Choctaw - Clay 500 kV	None	710MWx2	2028	2028
Spring 2026	Batesville - Tallahatchie 161 kV	Batesville - East Batesville 161 kV	None	526MWx2	3072	3072

Table 4-4: Planning Year 2025–2026 Export Limits

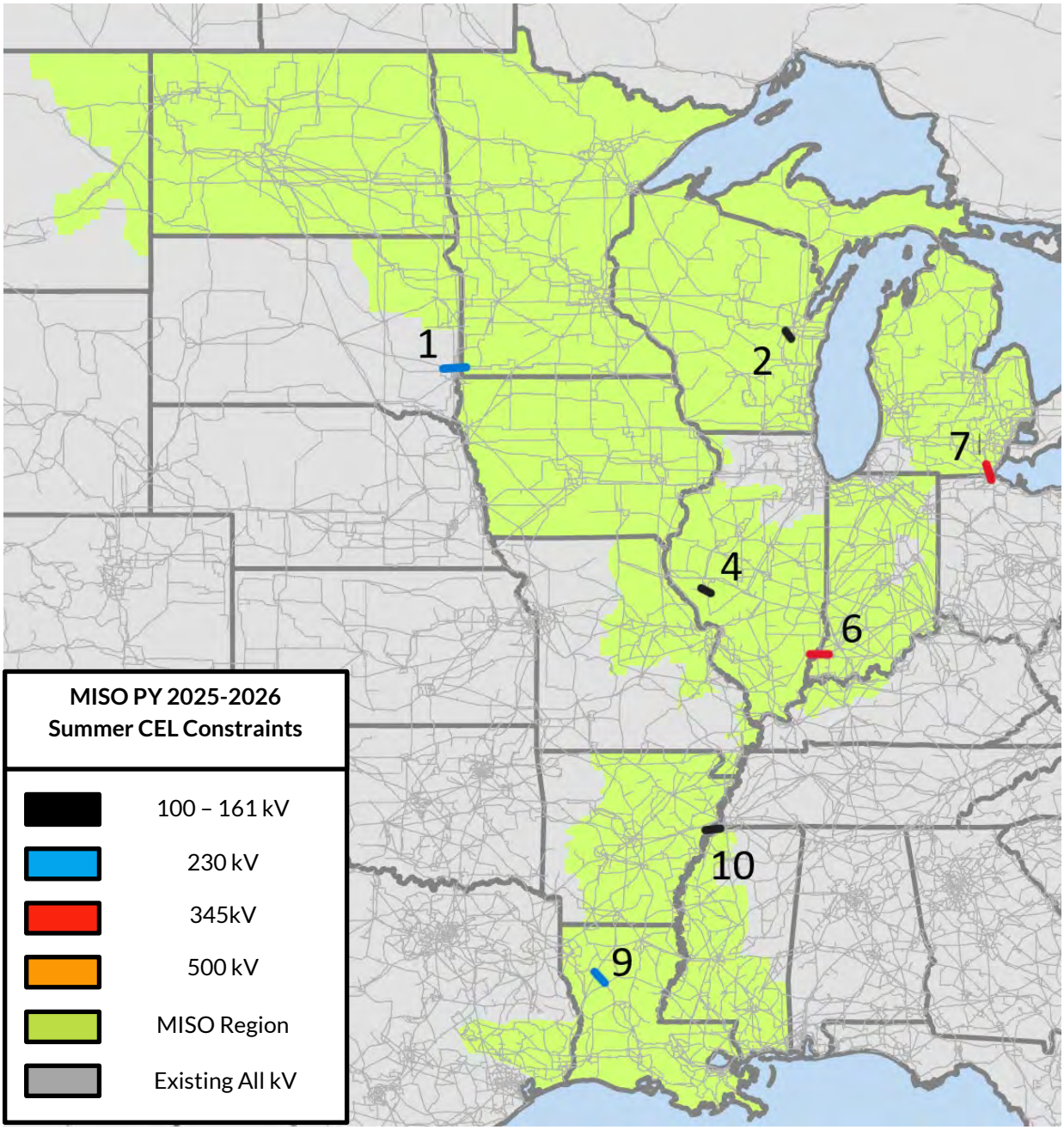


Figure 4-6: Planning Year 2025-2026 Summer Export Constraint Map

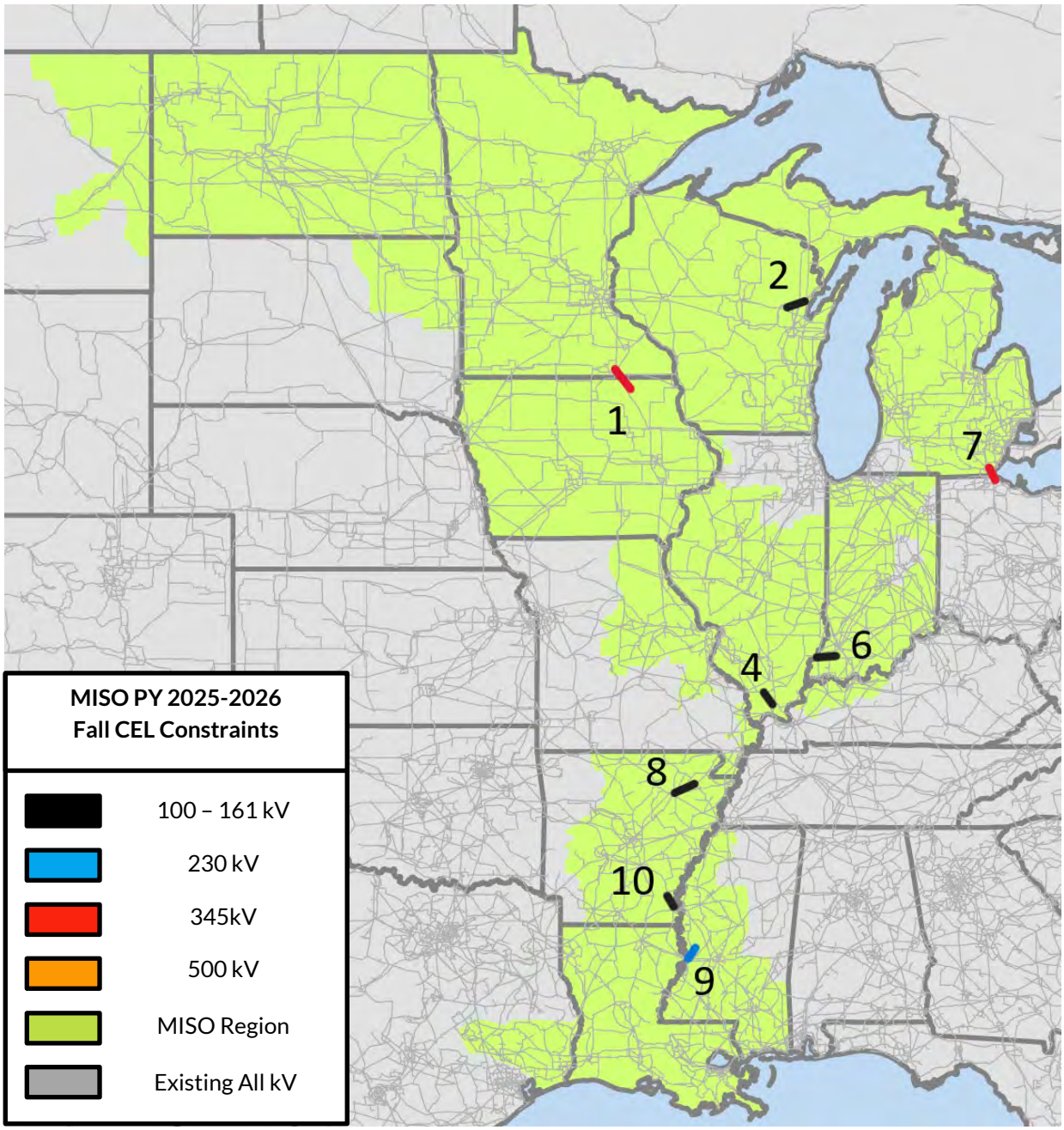


Figure 4-7: Planning Year 2025-2026 Fall Export Constraint Map

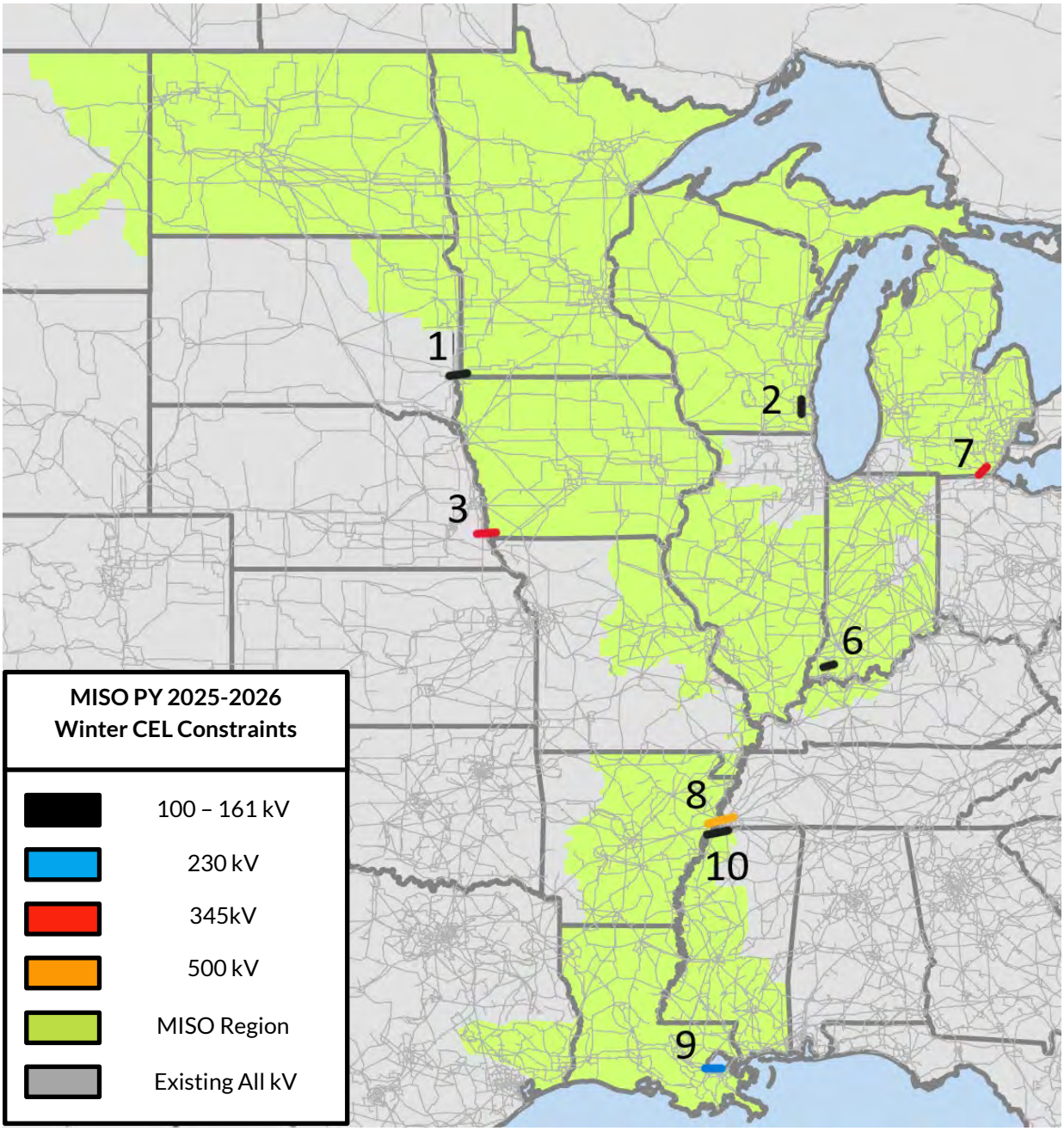


Figure 4-8: Planning Year 2025-2026 Winter Export Constraint Map

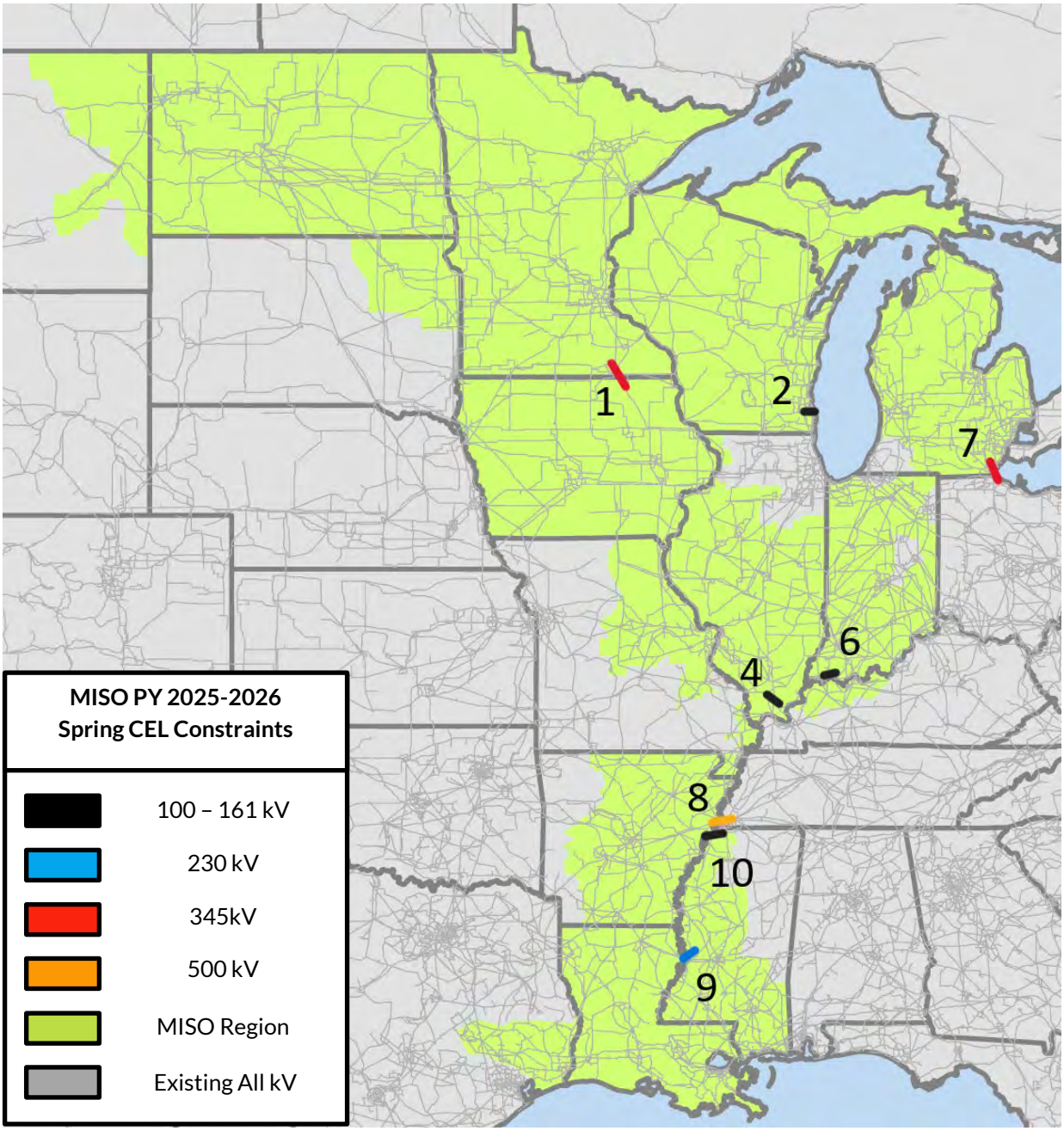


Figure 4-9: Planning Year 2025-2026 Spring Export Constraint Map

Appendix A: Capacity Import Limit Tier 1 & 2 Source Subsystem Definitions

MISO Local Resource Zone 1

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
XEL / 600	ALTW / 627	WEC / 295
MP / 608	ALTE / 694	MIUP / 296
SMMPA / 613	WPS / 696	AMMO / 356
GRE / 615	MGE / 697	AMIL / 357
OTP / 620		MPW / 633
MDU / 661		MEC / 635
BEPC-MISO / 663		
DPC / 680		

MISO Local Resource Zone 2

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #	
WEC / 295	METC / 218	NIPS / 217	OTP / 620
MIUP / 296	XEL / 600	ITCT / 219	MPW / 633
ALTE / 694	MP / 608	AMMO / 356	MEC / 635
WPS / 696	ALTW / 627	AMIL / 357	
MGE / 697	DPC / 680	SMMPA / 613	
UPPC / 698		GRE / 615	

MISO Local Resource Zone 3

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #	
ITCM / 627	AMMO / 356	HE / 207	GLHB / 362
MPW / 633	AMIL / 357	DEI / 208	MP / 608
MEC / 635	XEL / 600	NIPS / 217	GRE / 615
	SMMPA / 613	WEC / 295	OTP / 620
	DPC / 680	CWLP / 360	WPS / 696
	ALTE / 694	SIPC / 361	MGE / 697

MISO Local Resource Zone 4

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #	
AMIL / 357	HE / 207	SIGE / 210	DPC / 680
CWLP / 360	DEI / 208	IPL / 216	ALTE / 694
SIPC / 361	NIPS / 217	METC / 218	
GLHB / 362	BREC / 314	HMPL / 315	
GLH / 373	AMMO / 356	XEL / 600	
	ITCM / 627	SMMPA / 613	
	MEC / 635	MPW / 633	

MISO Local Resource Zone 5

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #	
CWLD / 333	AMIL / 357	HE / 207	SMMPA / 613
AMMO / 356	GLHB / 362	DEI / 208	MPW / 633
	ALTW / 627	NIPS / 217	DPC / 680
	MEC / 635	CWLP / 360	ALTE / 694
		SIPC / 361	
		XEL / 600	

MISO Local Resource Zone 6

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
HE / 207	METC / 218	ITCT / 219
DEI / 208	AMIL / 357	MIUP / 296
SIGE / 210	SIPC / 361	AMMO / 356
IPL / 216		CWLP / 360
NIPS / 217		GLHB / 362
BREC / 314		ALTW / 627
HMPL / 315		MEC / 635

MISO Local Resource Zone 7

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
METC / 218	NIPS / 217	DEI / 208
ITCT / 219	MIUP / 296	WEC / 295
		AMIL / 356
		WPS / 696
		UPPC / 698

MISO Local Resource Zone 8

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
EES-EAI / 327	EES-EMI / 326	LAGN / 332
	EES / 351	SMEPA / 349
		CLEC / 502
		LAFA / 503

MISO Local Resource Zone 9

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
LAGN / 332	EES-EMI / 326	SMEPA / 349
EES / 351	EES-EAI / 327	
CLEC / 502		
LAFA / 503		
LEPA / 504		

MISO Local Resource Zone 10

LRZ Area Name / Area #	Tier-1 Area Name / Area #	Tier-2 Area Name / Area #
EES-EMI / 326	EES-EAI / 327	LAGN / 332
SMEPA / 349	EES / 351	CLEC / 502
		LAFA / 503

Appendix B: Compliance Conformance Table

Requirements under: Standard BAL-502-RF-03	Response
R1 The Planning Coordinator shall perform and document a Resource Adequacy analysis annually. The Resource Adequacy analysis shall:	The Planning Year 2025-2026 LOLE Study Report is the annual Resource Adequacy Analysis for the peak season of June 2025 through May 2026 and beyond. Analysis of Planning Year 2025-2026 is in Sections 1.2 and 2.1. Analysis of Future Years 2025-2034 is included in Appendix D as an addendum to the study report.
R1.1 Calculate a planning reserve margin that will result in the sum of the probabilities for loss of Load for the integrated peak hour for all days of each planning year[1] analyzed (per R1.2) being equal to 0.1. (This is comparable to a "one day in 10 years" criterion).	Section 3.6 of this report outlines the utilization of LOLE in the reserve margin determination. "The risk metrics were derived through probabilistic modeling of the system, first solving to the industry standard annual LOLE risk target of 1 day in 10 years, or 0.1 day per year, and then solving to the minimum seasonal LOLE criteria of 0.01 LOLE for seasons demonstrating minimal risk.
R1.1.1 The utilization of Direct Control Load Management or curtailment of Interruptible Demand shall not contribute to the loss of Load probability.	Section 3.4 of this report. "Direct Control Load Management and Interruptible Demand types of demand response were included in the LOLE model as resources. Demand response is dispatched in the LOLE model to avoid load shed during simulation when all other available generation has been exhausted."
R1.1.2 The planning reserve margin developed from R1.1 shall be expressed as a percentage of the median forecast peak Net Internal Demand (planning reserve margin).	Section 1.2 of this report. "…the ratio of MISO capacity to forecasted MISO system peak demand yielded a Planning Reserve Margin UCAP…"
R1.2 Be performed or verified separately for each of the following planning years.	Covered in the segmented R1.2 responses below.
R1.2.1 Perform an analysis for Year One.	In Sections 1.2 and 2.1, a full analysis was performed for Planning Year 2025-2026.
R1.2.2 Perform an analysis or verification at a minimum for one year in the 2 through 5-year period and at a minimum one year in the 6 though 10-year period.	Analysis of Planning Years 2028-2029 and 2030-2031 are included in Appendix D as an addendum to the study report.

Requirements under: Standard BAL-502-RF-03	Response
R1.2.2.1 If the analysis is verified, the verification must be supported by current or past studies for the same planning year.	Analysis was performed.
R1.3 Include the following subject matter and documentation of its use:	Covered in the segmented R1.3 responses below.
R1.3.1 Load forecast characteristics: • Median (50:50) forecast peak load • Load Forecast Uncertainty (reflects variability in the Load forecast due to weather and regional economic forecasts) • Load Diversity • Seasonal Load Variations • Daily demand modeling assumptions (firm, interruptible) • Contractual arrangements concerning curtailable/Interruptible Demand	Median forecasted load – In Section 3.4 of this report: "The sixth and final step of the load training process is to average the monthly peak loads of the 30 years of predicted load shapes and adjust the load dataset to match each LRZ's total monthly zonal Coincident Peak Demand forecast provided by the Load Serving Entities for each of the study years." Load Forecast Uncertainty – A detailed explanation of the weather and economic uncertainties is given in Section 3.4. Load Diversity / Seasonal Load Variations — In Section 3.4 of this report: "Every year, the Load Serving Entities submit new load forecasts to MISO by November 1 and, every year, MISO utilizes these load forecasts in the load development process for the LOLE study to align the load in the model with the anticipated load growth forecasted within each Local Resource Zone. The Planning Year 2025-2026 LOLE analysis used a load training process pared with neural net software to establish a correlated relationship between the most recent 5 years of historical weather and load data. This relationship was then applied to 30 years of hourly historical load data to create 30 years of load shapes for each LRZ to capture both load diversity and seasonal variability." Demand Modeling Assumptions / Curtailable and Interruptible Demand — All Load Modifying Resources must first meet registration requirements through Module E of the MISO Tariff. As stated in Section 3.2.6: "Each demand response program was modeled individually with a monthly capability, limited by duration and the number of times each program can be called upon for each season."

Requirements under: Standard BAL-502-RF-03	Response
R1.3.2 Resource characteristics: • Historic resource performance and any projected changes • Seasonal resource ratings • Modeling assumptions of firm capacity purchases from and sales to entities outside the Planning Coordinator area • Resource planned outage schedules, deratings, and retirements • Modeling assumptions of intermittent and energy limited resource such as wind and cogeneration • Criteria for including planned resource additions in the analysis	Section 3.2 details how historic performance data and seasonal ratings are gathered and includes discussion of future units and the modeling assumptions for intermittent capacity resources. A more detailed explanation of firm capacity purchases and sales is in Section 3.5.
R1.3.3 Transmission limitations that prevent the delivery of generation reserves.	Annual MTEP deliverability analysis identifies transmission limitations preventing delivery of generation reserves. Additionally, Section 4 of this report details the transfer analysis to capture transmission constraints limiting capacity transfers.
R1.3.3.1 Criteria for including planned Transmission Facility additions in the analysis.	Inclusion of the planned transmission addition assumptions is detailed in Section 4.2.3.
R1.3.4 Assistance from other interconnected systems including multi-area assessment considering Transmission limitations into the study area.	Section 3.5 provides the analysis on the treatment of external support assistance and limitations.

Requirements under: Standard BAL-502-RF-03	Response
R1.4 Consider the following resource availability characteristics and document how and why they were included in the analysis or why they were not included: • Availability and deliverability of fuel • Common mode outages that affect resource availability • Environmental or regulatory restrictions of resource availability • Any other demand (Load) response programs not included in R1.3.1 • Sensitivity to resource outage rates • Impacts of extreme weather/drought conditions that affect unit availability • Modeling assumptions for emergency operation procedures used to make reserves available • Market resources not committed to serving Load (uncommitted resources) within the Planning Coordinator area	Fuel availability, environmental restrictions, common mode outage, and extreme weather conditions are all part of the historical availability performance data that goes into the unit's EFORd statistic. The use of the EFORd values is covered in Section 3.2.1. The use of demand response programs is mentioned in Section 3.2.6. The effects of resource outage characteristics on the reserve margin are outlined in Section 3.6.2 by examining the difference between PRM ICAP and PRM UCAP values.
R1.5 Consider Transmission maintenance outage schedules and document how and why they were included in the Resource Adequacy analysis or why they were not included.	Transmission maintenance schedules were not included in the analysis of the transmission system due to the limited availability of reliable long-term maintenance schedules and minimal impact to the results of the analysis. However, Section 4 treats worst-case theoretical outages by performing First Contingency Total Transfer Capability (FCTTC) analysis for each LRZ, by modeling NERC Category P0 (system intact) and Category P1 (N-1) contingencies.
R1.6 Document that capacity resources are appropriately accounted for in its Resource Adequacy analysis.	MISO internal resources are among the quantities documented in the tables provided in Sections 1 and 2.
R1.7 Document that all Load in the Planning Coordinator area is accounted for in its Resource Adequacy analysis.	MISO load is among the quantities documented in the tables provided in Sections 1 and 2.
R2 The Planning Coordinator shall annually document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis.	In Sections 1 and 2, the peak load and estimated amount of resources for Planning Year 2025-2026 are shown. This includes the detail for each transmission constrained sub-area.
R2.1 This documentation covers each of the years in year one through ten.	Appendix D details the future Planning Year analysis.

Requirements under: Standard BAL-502-RF-03	Response
R2.2 This documentation includes the Planning Reserve margin calculated per requirement R1.1 for each of the three years in the analysis.	The prompt Planning Year seasonal PRM values are covered in Section 1.2. The outyear Planning Years 4 (2028-2029) and 6 (2030-2031) are covered in Appendix D.
R2.3 The documentation as specified per requirement R2.1 and R2.2 shall be publicly posted no later than 30 calendar days prior to the beginning of Year One.	The final Planning Year 2025-2026 LOLE Study Report was posted publicly in November 2024, several months prior to the start of the applicable Planning Year.
R3 The Planning Coordinator shall identify any gaps between the needed amount of planning reserves defined in Requirement R1, Part 1.1 and the projected planning reserves documented in Requirement R2.	Sections 1 and 2 show the differences between the needed amount and the projected planning reserves for Planning Year 2025-2026. The amount of planning reserves needed for the outyear Planning Years 4 (2028-2029) and 6 (2030-2031) are covered in Appendix D.

Appendix C: Acronyms List Table

CEL	Capacity Export Limit
CIL	Capacity Import Limit
CPNode	Commercial Pricing Node
DF	Distribution Factor
EFORd	Equivalent Forced Outage Rate demand
ELCC	Effective Load Carrying Capability
ERZ	External Resource Zone
EUE	Expected Unserved Energy
FERC	Federal Energy Regulatory Commission
FCITC	First Contingency Incremental Transfer Capability
FCTTC	First Contingency Total Transfer Capability
GADS	Generator Availability Data System
GLT	Generation Limited Transfer
GVTC	Generation Verification Test Capacity
ICAP	Installed Capacity
LBA	Local Balancing Authority
LCR	Local Clearing Requirement
LFE	Load Forecast Error
LFU	Load Forecast Uncertainty
LOLE	Loss of Load Expectation
LOLEWG	Loss of Load Expectation Working Group
LRR	Local Reliability Requirement
LRZ	Local Resource Zones
LSE	Load Serving Entity
MARS	Multi-Area Reliability Simulation
MECT	Module E Capacity Tracking
MISO	Midcontinent Independent System Operator
MOD	Model on Demand
MTEP	MISO Transmission Expansion Plan
MW	Megawatt
MWh	Megawatt hours
NERC	North American Electric Reliability Corporation

PRA	Planning Resource Auction
PRM	Planning Reserve Margin
PRM ICAP	PRM Installed Capacity
PRM UCAP	PRM Unforced Capacity
PRMR	Planning Reserve Margin Requirement
PSS E	Power System Simulator for Engineering
RCF	Reciprocal Coordinating Flowgate
RDS	Redispatch
RPM	Reliability Pricing Model
SAC	Seasonal Accredited Capacity
SERVM	Strategic Energy & Risk Valuation Model
SPS	Special Protection Scheme
TARA	Transmission Adequacy and Reliability Assessment
UCAP	Unforced Capacity
XEFORd	Equivalent Forced Outage Rate demand with adjustment to exclude events outside management control
ZIA	Zonal Import Ability
ZEA	Zonal Export Ability

Appendix D: Outyear PRM Results

For Planning Year 2028-2029, the ratio of MISO capacity to forecasted MISO system peak demand yielded a Planning Reserve Margin UCAP of 8.5 percent for the Summer season. Numerous values and calculations went into determining the four-year-out MISO system seasonal PRM UCA, supporting values are seen in Table D-1. In addition to the LOLE results, SERVM has the ability to calculate several other probabilistic metrics, resulting values for Loss of Load Hours (LOLH) and Expected Unserved Energy (EUE) for each season of the 2028-2029 Planning Year are shown below in Table D-2.

D.1 Planning Year 2028-2029 MISO Planning Reserve Margin Results

MISO Planning Reserve Margin (PRM)	PY 2028-2029 Summer	PY 2028-2029 Fall	PY 2028-2029 Winter	PY 2028-2029 Spring	Formula Key
MISO System Peak Demand (MW)	129,963	114,031	109,039	104,253	[A]
Installed Capacity (ICAP) (MW)	153,551	150,473	157,792	158,083	[B]
Unforced Capacity (UCAP) (MW)	143,488	138,424	137,443	144,560	[C]
Firm External Support ICAP (MW)	1,986	2,315	2,738	2,423	[D]
Firm External Support UCAP (MW)	1,935	2,215	2,594	2,309	[E]
Adjustment to ICAP (MW)	(4,350)	(9,400)	(8,640)	(14,850)	[F]
Adjustment to UCAP (MW)	(4,350)	(9,400)	(8,640)	(14,850)	[G]
ICAP PRM Requirement (PRMR) (MW)	151,187	143,388	151,890	145,657	[H] = [B]+[D]+[F]
UCAP PRM Requirement (PRMR) (MW)	141,073	131,239	131,398	132,019	[I] = [C]+[E]+[G]
MISO PRM ICAP	**16.3%**	**25.7%**	**39.3%**	**39.7%**	[J]=[H]-[A]/[A]
MISO PRM UCAP	**8.5%**	**15.1%**	**20.5%**	**26.6%**	[K]=[I]-[A]/[A]

Table D-1: Planning Year 2028-2029 MISO System Planning Reserve Margins

D.1.1 Additional Risk Metric Statistics

MISO LOLE Statistics	PY 2028-2029 Summer	PY 2028-2029 Fall	PY 2028-2029 Winter	PY 2028-2029 Spring
Loss of Load Expectation (LOLE) [days/year]	0.100	0.010	0.010	0.010
Loss of Load Hours (LOLH) [hours/year]	0.143	0.011	0.013	0.013
Expected Unserved Energy (EUE) [megawatt-hours/year]	307.123	12.808	11.574	14.615

Table D-2: PY 2028-2029 Additional Risk Metric Statistics

D.2 Planning Year 2030-2031 MISO Planning Reserve Margin Results

For Planning Year 2030-2031, the ratio of MISO capacity to forecasted MISO system peak demand yielded a Planning Reserve Margin UCAP of 8.5 percent for the Summer season. Numerous values and calculations went into determining the six-year-out MISO system seasonal PRM UCA, supporting values are seen in Table D-3. In addition to the LOLE results, SERVM has the ability to calculate several other probabilistic metrics, resulting values for Loss of Load Hours (LOLH) and Expected Unserved Energy (EUE) for each season of the 2030-2031 Planning Year are shown below in Table D-4.

MISO Planning Reserve Margin (PRM)	**PY 2030-2031** Summer	**PY 2030-2031** Fall	**PY 2030-2031** Winter	**PY 2030-2031** Spring	**Formula Key**
MISO System Peak Demand (MW)	131,381	115,692	110,450	105,291	[A]
Installed Capacity (ICAP) (MW)	158,093	155,519	162,465	160,212	[B]
Unforced Capacity (UCAP) (MW)	147,627	143,109	141,998	146,462	[C]
Firm External Support ICAP (MW)	1,986	2,315	2,738	2,423	[D]
Firm External Support UCAP (MW)	1,935	2,215	2,594	2,309	[E]
Adjustment to ICAP (MW)	(7,075)	(11,500)	(10,687)	(14,600)	[F]
Adjustment to UCAP (MW)	(7,075)	(11,500)	(10,687)	(14,600)	[G]
ICAP PRM Requirement (PRMR) (MW)	153,004	146,335	154,516	148,036	[H] = [B]+[D]+[F]
UCAP PRM Requirement (PRMR) (MW)	142,487	133,825	133,906	134,171	[I] = [C]+[E]+[G]
MISO PRM ICAP	**16.5%**	**26.5%**	**39.9%**	**40.6%**	[J]=[H]-[A]/[A]
MISO PRM UCAP	**8.5%**	**15.7%**	**21.2%**	**27.4%**	[K]=[I]-[A]/[A]

Table D-3: Planning Year 2030-2031 MISO System Planning Reserve Margins

D.2.1 Additional Risk Metric Statistics

MISO LOLE Statistics	**PY 2030-2031** Summer	**PY 2030-2031** Fall	**PY 2030-2031** Winter	**PY 2030-2031** Spring
Loss of Load Expectation (LOLE) [days/year]	0.100	0.010	0.010	0.010
Loss of Load Hours (LOLH) [hours/year]	0.138	0.010	0.012	0.012
Expected Unserved Energy (EUE) [megawatt-hours/year]	309.609	15.855	10.990	11.952

Table D-4: PY 2030-2031 Additional Risk Metric Statistics

D.3 MISO Planning Reserve Margin Outyear Projections

Tables D-5, D-6, D-7, and D-8 show the outyear seasonal PRM projections. Years one, four, and six were probabilistically modeled. PRM projections in years two, three, and five are the result of interpolation of the years studied and years seven through ten are the resulting extrapolations of the outyear analyses.

Metric	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
PRM ICAP	15.7%	15.9%	16.1%	16.3%	16.4%	16.5%	16.6%	16.8%	16.9%	17.1%
PRM UCAP	7.9%	8.1%	8.3%	8.5%	8.5%	8.5%	8.6%	8.7%	8.8%	8.9%
Demand (GW)	123.6	125.7	127.8	130.0	130.7	131.4	132.9	134.5	136.1	137.6
ICAP (GW)	141.9	145.8	149.7	153.6	155.8	158.1	161.3	164.6	167.8	171.0

Table D-5: MISO Summer Planning Reserve Margin Outyear Projections

Metric	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
PRM ICAP	25.3%	25.5%	25.6%	25.7%	26.1%	26.5%	26.7%	27.0%	27.2%	27.4%
PRM UCAP	14.9%	14.9%	15.0%	15.1%	15.4%	15.7%	15.8%	16.0%	16.2%	16.3%
Demand (GW)	108.1	110.1	112.1	114.0	114.9	115.7	117.2	118.7	120.2	121.8
ICAP (GW)	142.7	145.3	147.9	150.5	153.0	155.5	158.1	160.6	163.2	165.7

Table D-6: MISO Fall Planning Reserve Margin Outyear Projections

Metric	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
PRM ICAP	38.6%	38.9%	39.1%	39.3%	39.6%	39.9%	40.1%	40.4%	40.7%	40.9%
PRM UCAP	18.4%	19.1%	19.8%	20.5%	20.9%	21.2%	21.8%	22.4%	22.9%	23.5%
Demand (GW)	103.9	105.6	107.3	109.0	109.7	110.4	111.8	113.1	114.4	115.7
ICAP (GW)	147.4	150.9	154.3	157.8	160.1	162.5	165.5	168.5	171.5	174.5

Table D-7: MISO Winter Planning Reserve Margin Outyear Projections

Metric	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034
PRM ICAP	38.8%	39.1%	39.4%	39.7%	40.2%	40.6%	41.0%	41.3%	41.7%	42.1%
PRM UCAP	25.3%	25.7%	26.2%	26.6%	27.0%	27.4%	27.9%	28.3%	28.7%	29.2%
Demand (GW)	98.7	100.5	102.4	104.3	104.8	105.3	106.6	107.9	109.3	110.6
ICAP (GW)	144.5	149.0	153.6	158.1	159.1	160.2	163.4	166.5	169.6	172.8

Table D-8: MISO Spring Planning Reserve Margin Outyear Projections

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

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

Exhibit 84
MISO 2024-25 Auction Results

CORRECTIONS

Reposted 4/26/24

Slides Updated : 28, 40

Planning Resource Auction

Results for Planning Year 2024-25

April 25, 2024

MISO is projected to meet most Planning Year 2024-25 resource adequacy requirements; however, pressure persists with reduced capacity surplus across the region and a shortfall in Zone 5

- The Planning Resource Auction (PRA) clearing prices are flat across the region, except for fall and spring in Zone 5 (Missouri)
  - Zone 5 cleared at seasonal Cost of New Entry (CONE) in fall and spring due to inadequate capacity to meet its Local Clearing Requirement, driven by resource retirements and seasonal outages

All Zones (except Zone 5)	Zone 5:
• **Summer:** $30/MW-day	• **Summer:** $30/MW-day
• **Fall:** $15/MW-day	• **Fall:** $719.81/MW-day
• **Winter:** $0.75/MW-day	• **Winter:** $0.75/MW-day
• **Spring:** $34.10/MW-day	• **Spring:** $719.81/MW-day

- Capacity surplus across MISO eroded 30% in summer, primarily in the North/Central region
  - Retirements, reduced imports and higher requirements are insufficiently offset by new capacity
  - Trends are similar across other seasons except for winter which has a higher surplus
- Receding surplus, coupled with emerging risks due to fleet transition and new load additions, continue to pressure resource adequacy
- MISO's efforts under the Reliability Imperative — Reliability-Based Demand Curve, accreditation and attributes — are timely and responsive to the evolving resource adequacy risk

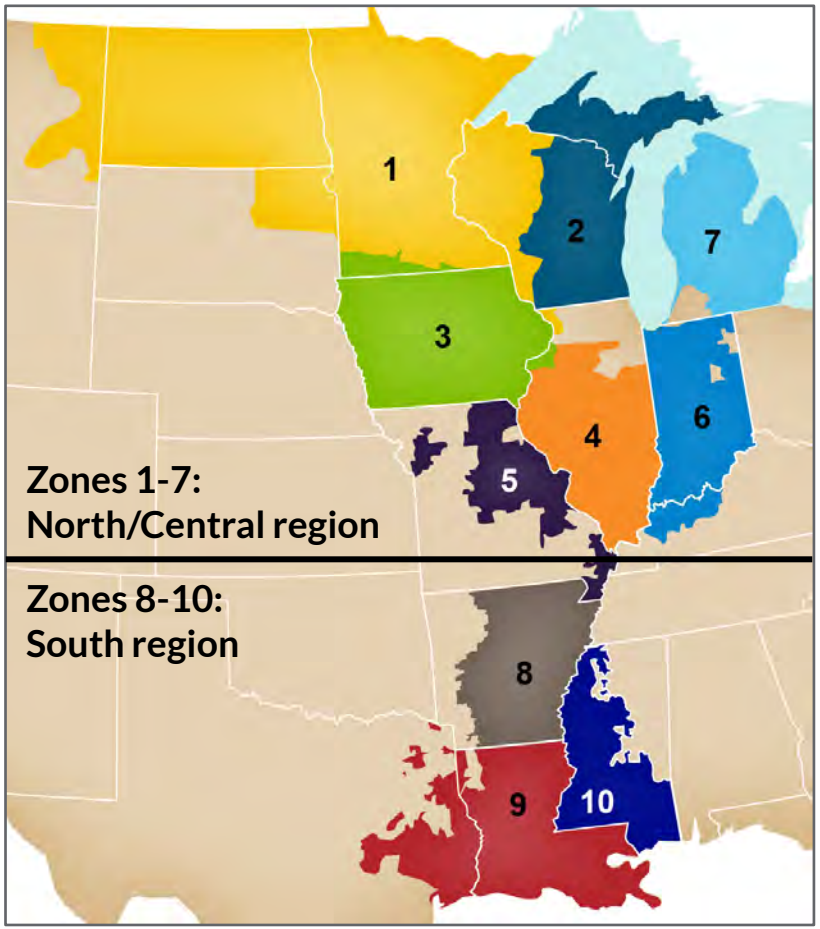
The 2024 PRA demonstrated sufficient capacity at the regional, sub-regional and zonal levels except for Zone 5

2024 PRA Results

Zone	Local Balancing Authorities	Summer	Fall	Winter	Spring
			(Price $/MW-Day)		
1	DPC, GRE, MDU, MP, NSP, OTP, SMP	30.00	15.00	0.75	34.10
2	ALTE, MGE, UPPC, WEC, WPS, MIUP	30.00	15.00	0.75	34.10
3	ALTW, MEC, MPW	30.00	15.00	0.75	34.10
4	AMIL, CWLP, SIPC, GLH	30.00	15.00	0.75	34.10
5	AMMO, CWLD	30.00	719.81	0.75	719.81
6	BREC, CIN, HE, IPL, NIPS, SIGE	30.00	15.00	0.75	34.10
7	CONS, DECO	30.00	15.00	0.75	34.10
8	EAI	30.00	15.00	0.75	34.10
9	CLEC, EES, LAFA, LAGN, LEPA	30.00	15.00	0.75	34.10
10	EMBA, SME	30.00	15.00	0.75	34.10
ERZ	KCPL, OPPD, WAUE (SPP), PJM, OVEC, LGEE, AECI, SPA, TVA	30.00	15.00	0.75	34.10

Highlighted values are CONE pricing

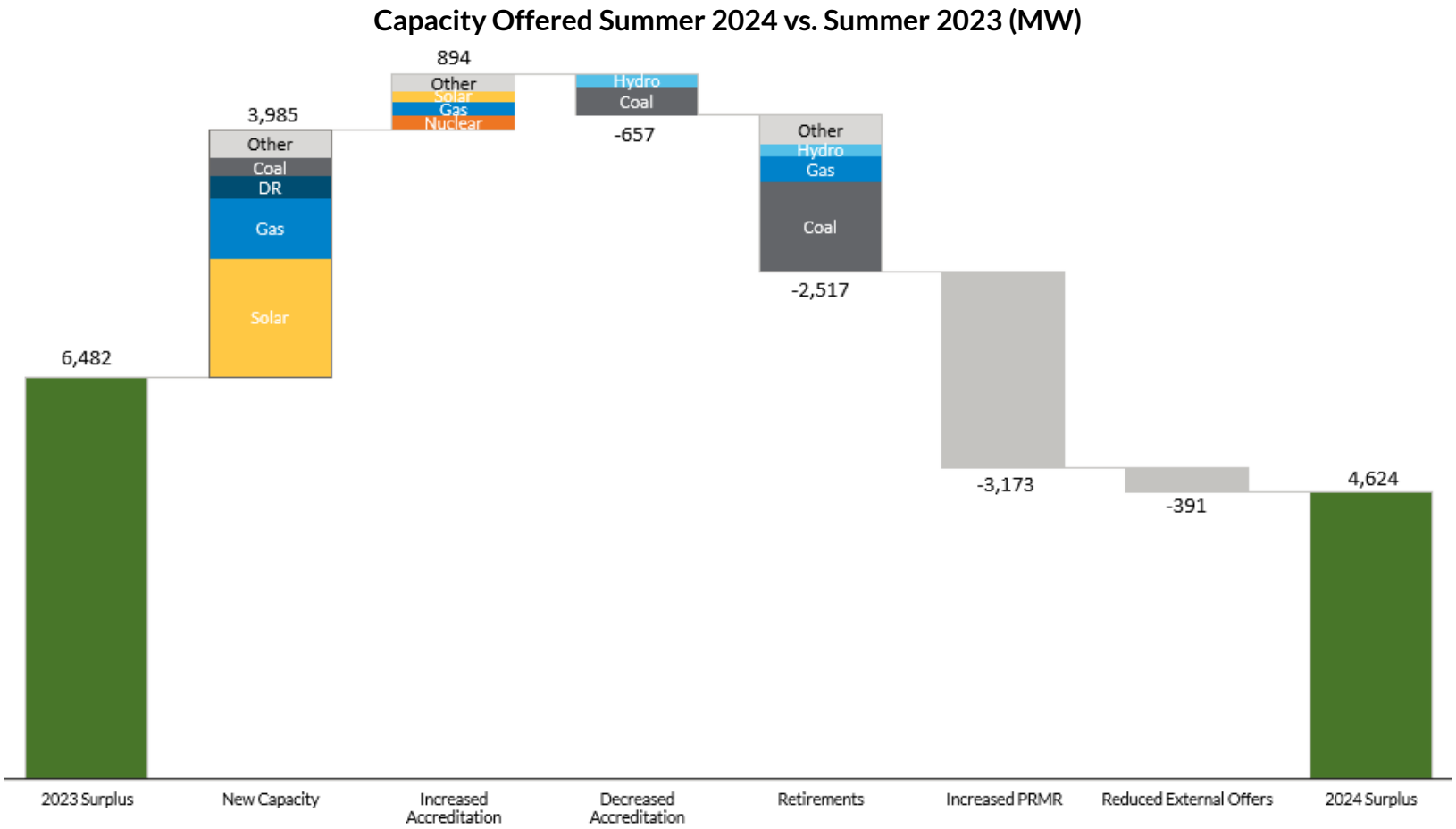
MISO Resource Adequacy Zones



ERZ: External Resource Zones

The MISO footprint showed approximately a 30% decrease in surplus but remained adequate

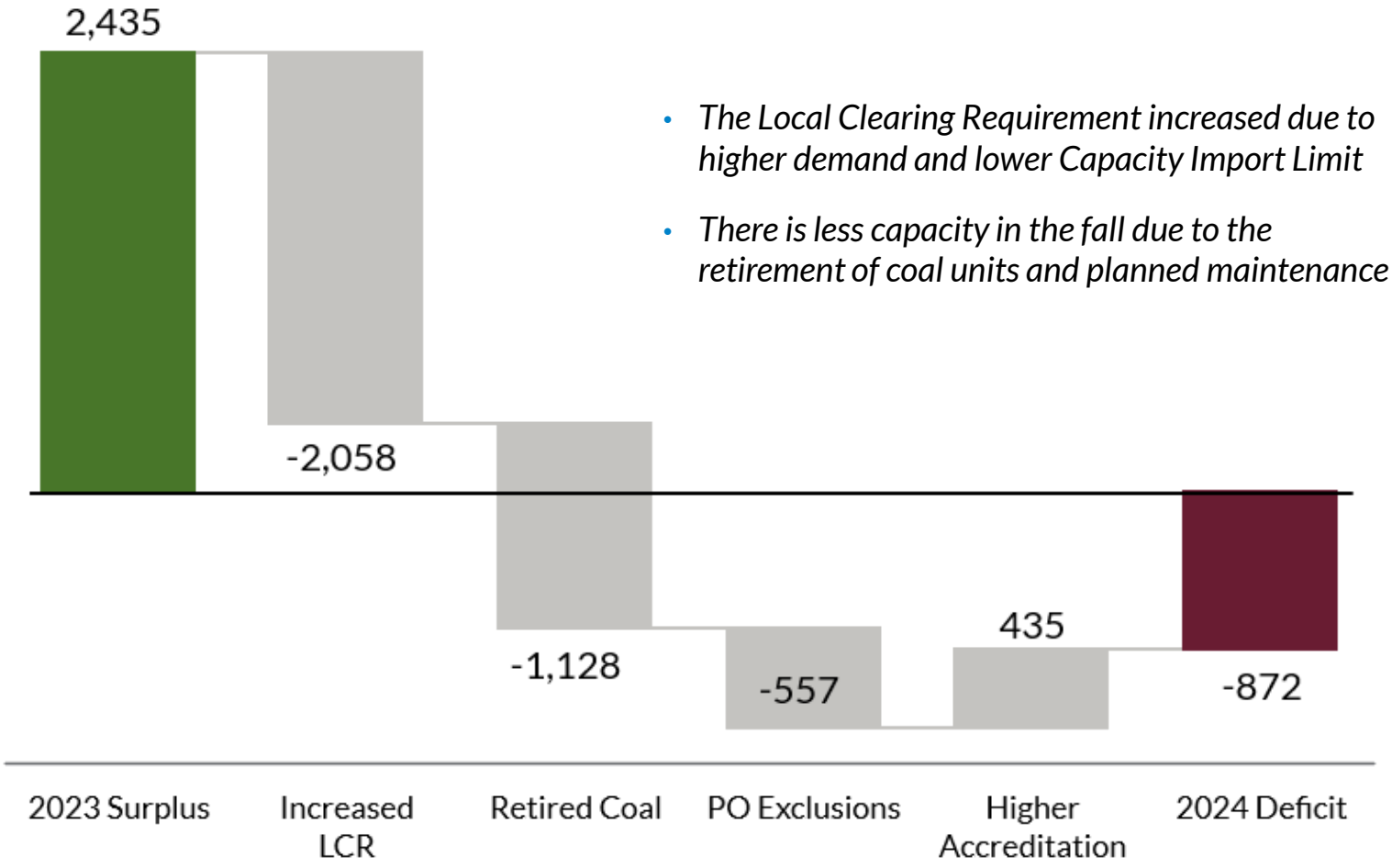
Reduced surplus driven by retirements, increased PRMR and reduced external offers



DR: Demand Response *Capacity indicated is offered accredited value*

A combination of higher Local Clearing Requirement and reduced capacity contributed to Zone 5 deficiency in the fall

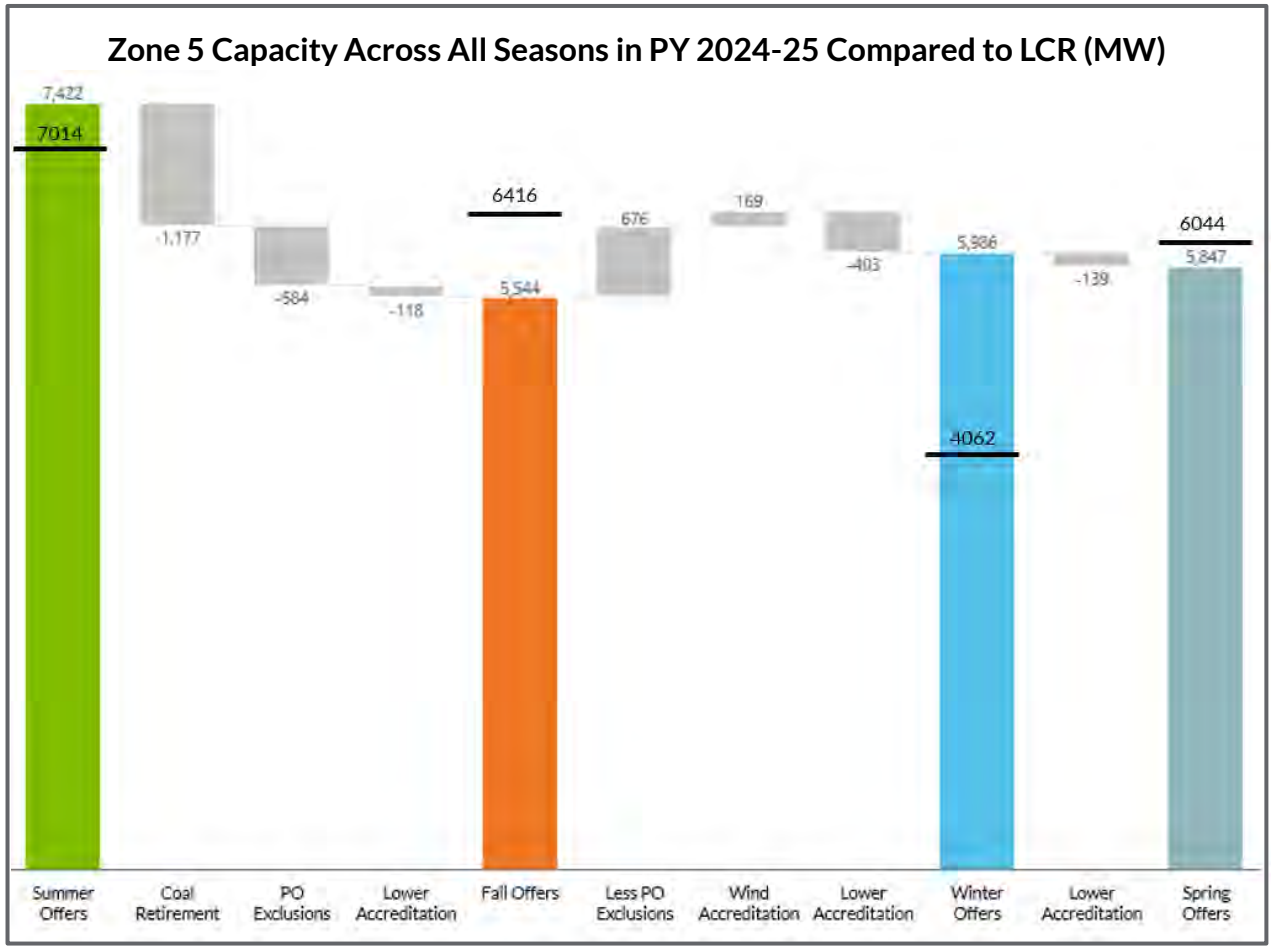
Zone 5 Fall 2024 Capacity Changes Year-Over-Year (MW)



- *The Local Clearing Requirement increased due to higher demand and lower Capacity Import Limit*
- *There is less capacity in the fall due to the retirement of coal units and planned maintenance*

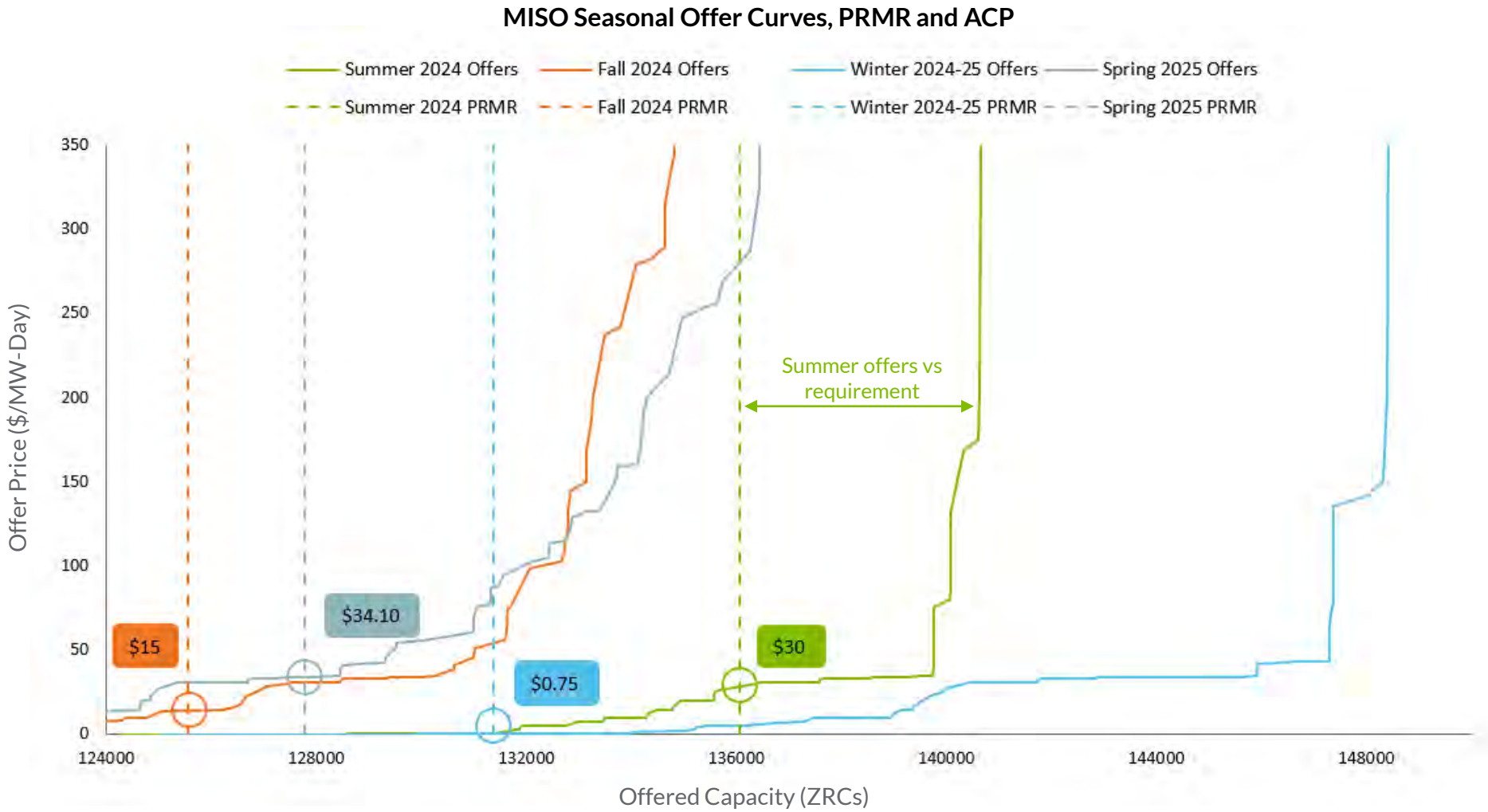
PO: Planned Outage

Seasonal variation in requirements and available capacity help explain the resource adequacy position in Zone 5



- Large coal retirements contribute to capacity deficiency; planned outages increase the gap in fall
- Lower Local Clearing Requirement in winter aids winter sufficiency
- Winter Local Clearing Requirement driven by relatively lower demand, Local Reliability Requirement and a higher import limit

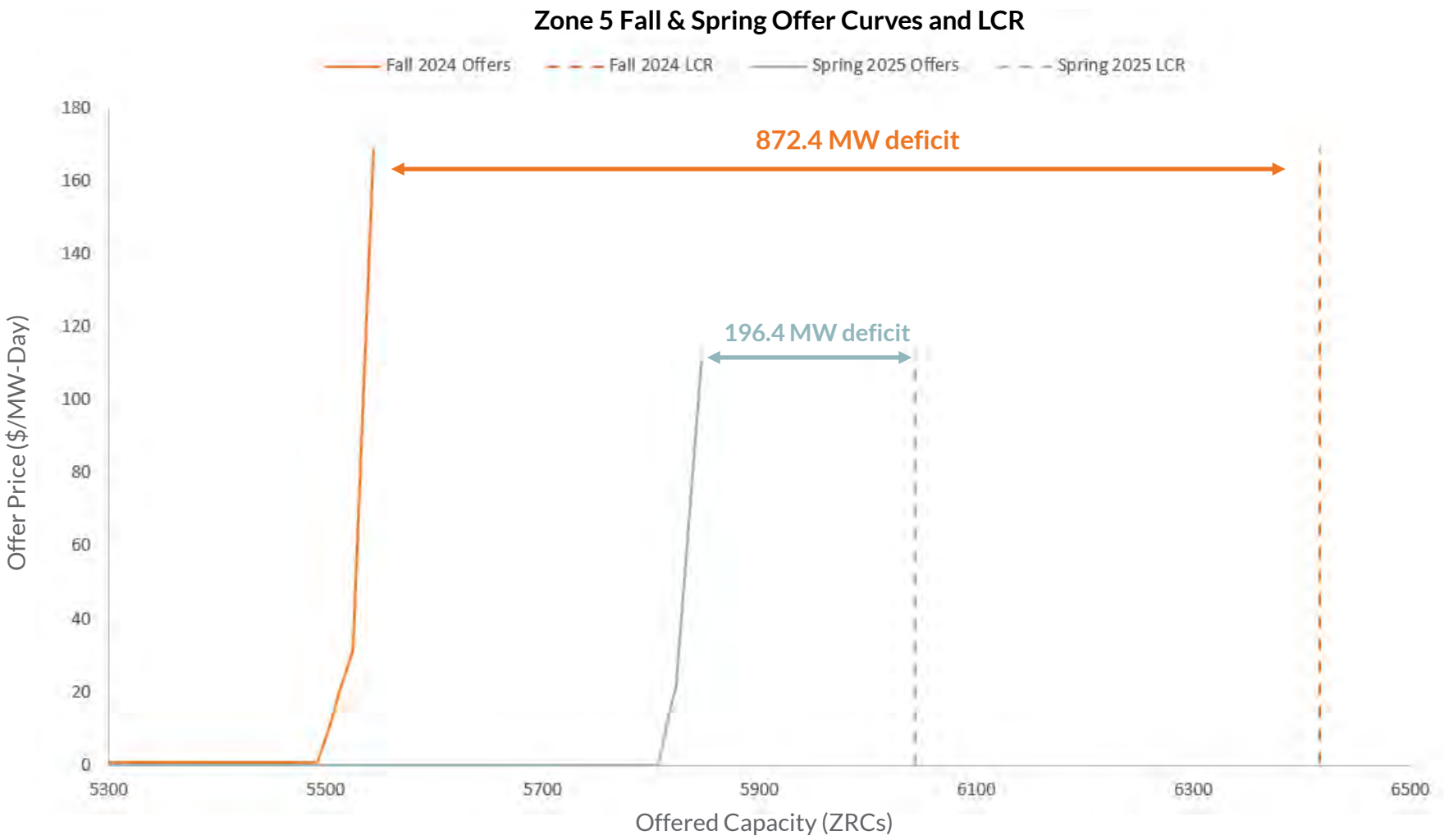
Adequate supply resulted in level auction clearing prices in each season across MISO, except for Zone 5



Y-axis truncated to provide a zoomed-in view.

PRMR: Planning Reserve Margin Requirement

Zone 5 did not have adequate capacity to meet Local Clearing Requirement in fall and spring, driving prices to seasonal CONE



Decreasing capacity surplus and the zonal deficiency, coupled with emerging risks due to fleet transition and new load additions, reinforce the urgency for ongoing reforms

Reforms under the Reliability Imperative are timely and responsive to the drivers contributing to resource adequacy challenges

DRIVERS

- Premature retirement of dispatchable resources
- Slow pace of resource additions
- Loss of accredited capacity & reliability attributes
- New load additions

MISO RESPONSE

Implemented
- Seasonal construct & thermal accreditation: implemented PY 2023-24

Filed
- Reliability-based demand curve: implementation PY 2025-26
- Resource accreditation: implementation PY 2028-29

Ongoing
- Load modifying resources accreditation: Target PY 2028-29
- Attributes roadmap and associated reforms

Next Steps

- **May 22**
  - Zonal deliverability benefits available at the May RASC
  - MISO publishes cleared Load Modifying Resources to Operations tools
- **May 24**
  - Posting of PRA masked offer data per Module E 69 A.7.4
- **June 1**
  - New Planning Year starts

Appendix

Table of Contents

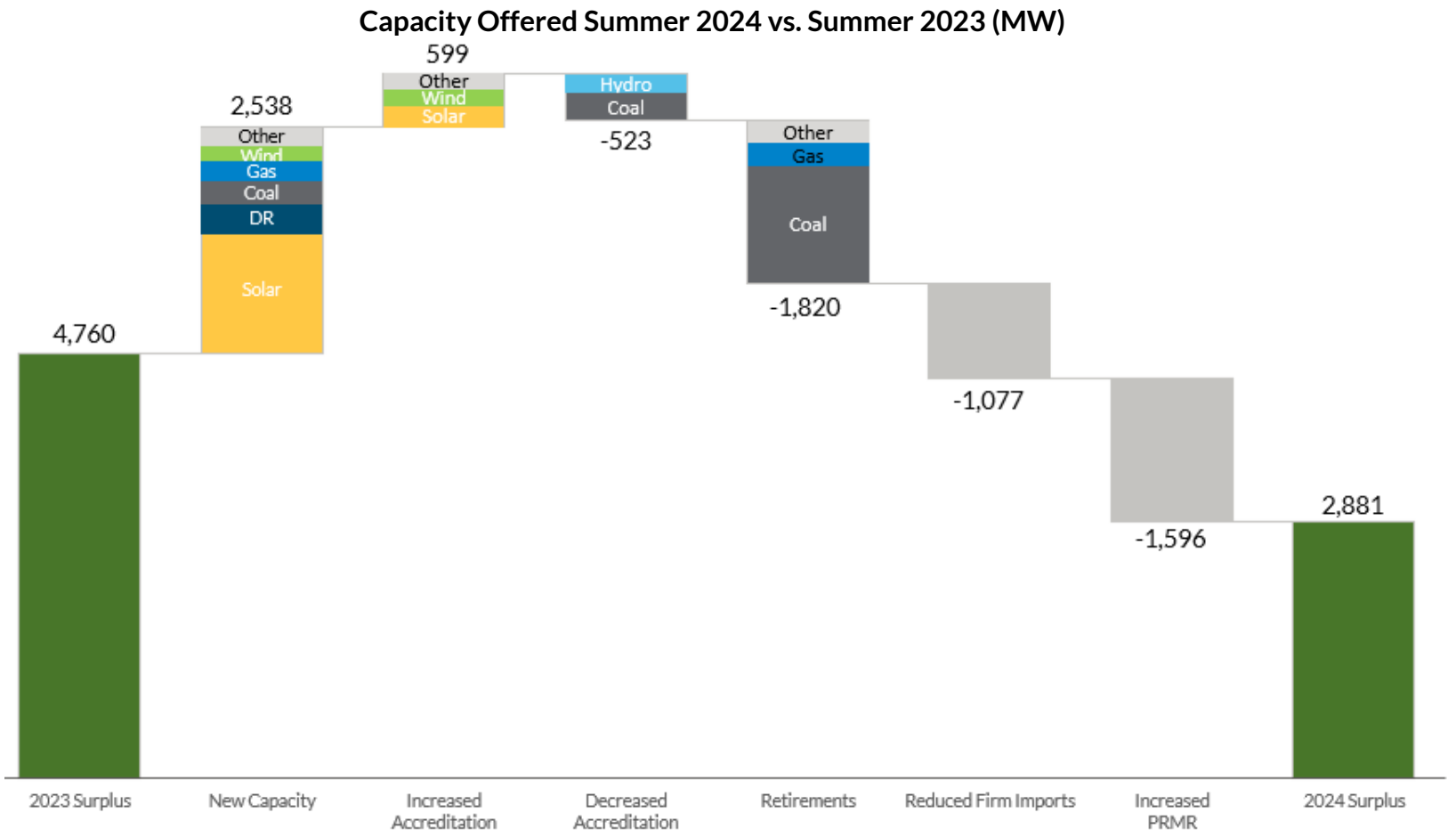
List of Acronyms	13
Capacity Surplus by Region (North-Central, South)	14
PRA Seasonal Results by Zone	16
Seasonal Supply Offered and Cleared Comparison Trend	20
Historical Seasonal Auction Clearing Price Comparison	25
2024-2025 Seasonal Offered Capacity & PRMR and Cleared Capacity, Exports & Imports maps	29
2024 PRA relative to 2023 OMS-MISO Survey	33
Coincident Peak Forecast	34
Planning Reserve Margin (%)	35
Wind Effective Load Carrying Capacity (%)	36
2024-2025 Seasonal Resource Adequacy Fulfillment	37
Wind and Solar Cleared SAC	38
Seasonal Cleared ZRC by Fuel Type	39
Planning Resource Mix Trend	41
2024-2025 Seasonally Cleared Load Modifying Resources Comparison	42
Zone 5 Spring LCR comparison	43
Zone 5 Local Clearing Requirement	44
Zone 5 Capacity Import Limits	45

Acronyms

ACP: Auction Clearing Price
ARC: Aggregator of Retail Customers
BTMG: Behind the Meter Generator
CIL: Capacity Import Limit
CEL: Capacity Export Limit
CONE: Cost of New Entry
DR: Demand Resource
ELCC: Effective Load Carrying Capability
EE: Energy Efficiency
ER: External Resource
ERZ: External Resource Zones
FRAP: Fixed Resource Adequacy Plan
ICAP: Installed Capacity
IMM: Independent Market Monitor
LCR: Local Clearing Requirement
LMR: Load Modifying Resource
LRR: Local Reliability Requirement
LRZ: Local Resource Zone
LSE: Load Serving Entity
PO: Planned Outage
PRA: Planning Resource Auction
PRM: Planning Reserve Margin
PRMR: Planning Reserve Margin Requirement
RASC: Resource Adequacy Sub-Committee
SAC: Seasonal Accredited Capacity
SS: Self Schedule
UCAP: Unforced Capacity
ZIA: Zonal Import Ability
ZRC: Zonal Resource Credit

The North/Central region showed a 40% decrease in surplus but remained adequate

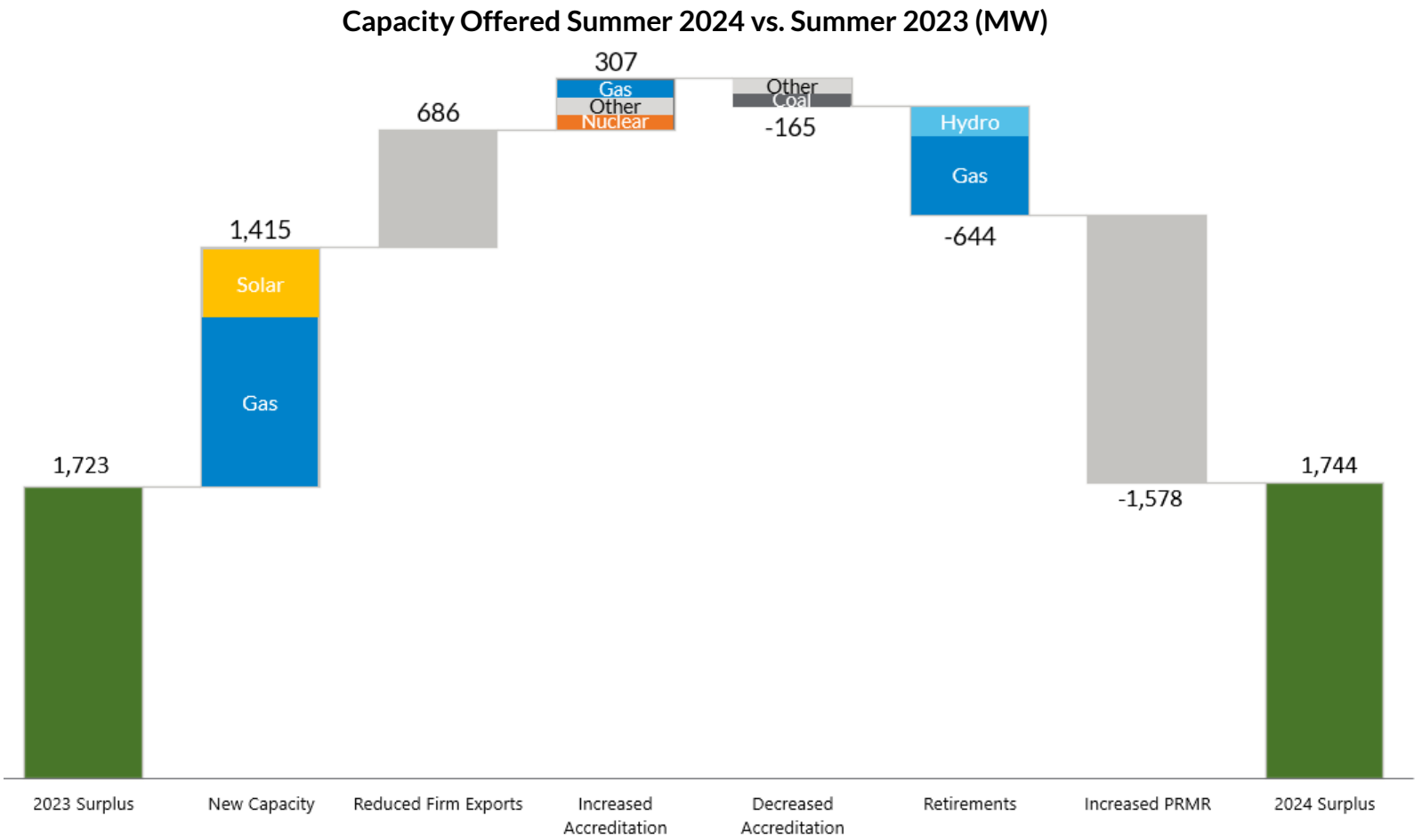
Reduced surplus driven by retirements, less imports and higher Planning Reserve Margin Requirement (PRMR)



DR: Demand Response *Capacity indicated is offered accredited value*

The South region continues to remain adequate with a comparable surplus to 2023

New generation and lower exports made up for the retirements and increased PRMR



Capacity indicated is offered accredited value

Summer 2024 PRA Results by Zone

	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	ERZ	System
PRMR	18,697	13,396	10,787	9,403	8,297	18,565	21,565	8,431	21,888	5,038	N/A	136,067
Offer Submitted (Including FRAP)	20,746	14,820	11,215	8,826	7,422	15,738	21,914	10,727	21,542	5,681	2,058	140,689
FRAP	13,961	11,216	4,248	636	0	1,109	1,352	349	166	1,616	201	34,852
Self Scheduled (SS)	4,754	3,150	6,618	5,185	7,414	9,152	20,283	9,614	18,172	3,368	1,698	89,408
Non-SS Offer Cleared	376	454	342	2,543	8	4,964	36	663	1,887	372	159	11,804
Committed (Offer Cleared + FRAP)	19,091	14,820	11,208	8,364	7,422	15,224	21,671	10,625	20,225	5,356	2,058	136,064
LCR	13,591	9,354	7,662	452	7,014	12,788	19,271	7,523	18,380	3,652	-	N/A
CIL	6,462	4,506	4,969	10,749	3,208	7,481	4,500	3,608	5,305	3,564	-	N/A
ZIA	6,460	4,506	4,911	9,857	3,208	7,197	4,490	3,444	4,794	3,564	-	N/A
Import	0	0	0	1,039	875	3,340	0	0	1,663	0	-	6,917
CEL	4,357	3,971	5,490	2,771	4,644	5,619	5,709	6,099	3,025	1,840	-	N/A
Export	394	1,424	421	0	0	0	107	2,195	0	318	2,058	6,917
ACP ($/MW-Day)	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	30.00	N/A

Values displayed in MW SAC

Fall 2024 PRA Results by Zone

	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	ERZ	System
PRMR	16,254	12,001	9,944	8,715	7,970	17,770	19,893	7,602	20,653	4,750	N/A	125,552
Offer Submitted (Including FRAP)	19,802	14,551	10,818	8,437	5,544	15,443	21,019	10,293	20,808	5,773	2,392	134,879
FRAP	11,904	10,092	3,411	547	0	918	1,240	340	151	1,531	208	30,341
Self Scheduled (SS)	4,670	2,590	6,095	6,109	5,492	7,625	19,165	8,990	17,167	3,444	1,677	83,023
Non-SS Offer Cleared	820	187	1,195	1,606	52	5,108	286	300	1,795	707	132	12,188
Committed (Offer Cleared + FRAP)	17,394	12,870	10,701	8,262	5,544	13,651	20,691	9,629	19,112	5,681	2,016	125,551
LCR	12,337	7,152	5,281	3,674	6,416	10,750	19,443	5,499	16,631	2,482	-	N/A
CIL	6,502	5,719	6,746	6,594	3,786	8,959	4,400	5,137	6,109	4,736	-	N/A
ZIA	6,500	5,719	6,684	5,699	3,786	8,661	4,390	4,942	5,608	4,736	-	N/A
Import	0	0	0	453	2,426	4,119	0	0	1,541	0	-	8,539
CEL	5,711	4,512	6,956	3,906	5,402	3,514	5,381	4,115	2,803	2,889	-	N/A
Export	1,140	868	757	0	0	0	799	2,027	0	931	2,016	8,539
ACP ($/MW-Day)	15.00	15.00	15.00	15.00	719.81	15.00	15.00	15.00	15.00	15.00	15.00	N/A

Values displayed in MW SAC

Winter 2024/2025 PRA Results by Zone

	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	ERZ	System
PRMR	18,528	11,704	10,628	9,300	8,375	19,180	17,366	8,977	22,194	5,127	N/A	131,377
Offer Submitted (Including FRAP)	23,738	14,545	15,243	8,097	5,986	15,888	23,032	10,121	22,877	6,338	2,575	148,438
FRAP	12,907	9,576	4,630	667	0	975	1,161	357	152	1,987	178	32,591
Self Scheduled (SS)	6,780	3,119	7,726	5,690	5,963	9,163	19,620	9,754	18,763	3,903	1,978	92,459
Non-SS Offer Cleared	0	0	484	1,563	0	2,341	55	1	1,866	7	10	6,327
Committed (Offer Cleared + FRAP)	19,687	12,695	12,840	7,920	5,963	12,479	20,836	10,112	20,782	5,897	2,167	131,377
LCR	16,972	7,189	10,804	3,133	4,062	10,219	17,597	7,379	18,888	4,809	-	N/A
CIL	4,693	5,523	5,668	6,707	4,477	8,532	4,656	4,364	5,200	3,219	-	N/A
ZIA	4,691	5,523	5,600	5,811	4,477	8,286	4,656	4,262	4,623	3,219	-	N/A
Import	0	0	0	1,380	2,412	6,701	0	0	1,412	0	-	11,905
CEL	5,174	4,772	9,011	4,674	6,229	1,401	5,753	5,780	2,323	2,993	-	N/A
Export	1,159	992	2,212	0	0	0	3,471	1,135	0	770	2,167	11,905
ACP ($/MW-Day)	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75	N/A

Values displayed in MW SAC

Spring 2025 PRA Results by Zone

	Z1	Z2	Z3	Z4	Z5	Z6	Z7	Z8	Z9	Z10	ERZ	System
PRMR	17,217	12,183	9,992	7,981	7,711	17,847	19,670	7,891	22,066	5,234	N/A	127,792
Offer Submitted (Including FRAP)	19,201	14,896	10,946	8,654	5,847	15,173	21,218	11,029	21,026	6,144	2,480	136,615
FRAP	12,319	9,949	3,950	638	0	1,039	1,256	329	152	1,559	197	31,387
Self Scheduled (SS)	4,226	3,458	6,220	5,790	5,806	7,979	18,316	9,504	15,711	3,387	1,823	82,219
Non-SS Offer Cleared	783	801	166	1,751	41	5,374	390	687	2,959	849	385	14,185
Committed (Offer Cleared + FRAP)	17,328	14,208	10,335	8,178	5,847	14,393	19,961	10,520	18,822	5,794	2,404	127,791
LCR	13,945	8,370	5,781	4,560	6,044	11,386	16,372	4,413	18,684	3,558	-	N/A
CIL	4,943	5,034	6,572	6,982	3,892	8,045	4,883	6,195	6,113	4,628	-	N/A
ZIA	4,941	5,034	6,514	5,083	3,892	7,730	4,883	6,030	5,598	4,628	-	N/A
Import	0	0	0	0	1,864	3,454	0	0	3,244	0	-	8,562
CEL	6,318	4,601	5,815	5,102	4,984	3,414	5,601	4,865	4,298	2,740	-	N/A
Export	111	2,025	344	197	0	0	291	2,629	0	561	2,404	8,562
ACP ($/MW-Day)	34.10	34.10	34.10	34.10	719.81	34.10	34.10	34.10	34.10	34.10	34.10	N/A

Values displayed in MW SAC

Summer Supply Offered and Cleared Comparison Trend

	Offered (ZRC)			Cleared (ZRC)		
Planning Resource	2022-23	Summer 2023	Summer 2024	2022-23	Summer 2023	Summer 2024
Generation	121,506.5	122,375.6	123,395.6	118,745.0	116,989.7	119,479.2
External Resources	3,563.9	4,514.6	4,430.4	3,563.9	4,072.5	4,309.8
Behind the Meter Generation	4,169.3	4,175.2	4,180.2	4,169.3	4,129.4	4,143.5
Demand Resources	7,574.9	8,303.5	8,660.2	7,525.0	7,694.6	8,109.4
Energy Efficiency	0.0	5.0	22.5	0.0	5.0	22.5
Total	**136,814.6**	**139,373.9**	**140,688.9**	**134,003.2**	**132,891.2**	**136,064.4**

Fall Supply Offered and Cleared Comparison Trend

	Offered (ZRC)		Cleared (ZRC)	
Planning Resource	Fall 2023	Fall 2024	Fall 2023	Fall 2024
Generation	121,403.5	119,745.3	111,713.8	111,791.5
External Resources	4,095.4	4,366.8	3,979.6	3,990.2
Behind the Meter Generation	3,874.2	3,877.9	3,842.8	3,789.7
Demand Resources	6,999.2	6,866.1	6,254.4	5,957.5
Energy Efficiency	4.9	22.5	4.8	22.5
Total	**136,377.2**	**134,878.6**	**125,795.4**	**125,551.4**

Winter Supply Offered and Cleared Comparison Trend

	Offered (ZRC)		Cleared (ZRC)	
Planning Resource	Winter 2023-2024	Winter 2024-2025	Winter 2023-2024	Winter 2024-2025
Generation	124,632.7	133,457.4	114,886.6	118,253.8
External Resources	3,937.1	3,973.0	3,334.6	3,313.3
Behind the Meter Generation	3,257.8	3,111.5	3,173.9	2,957.3
Demand Resources	7,644.4	7,866.4	6,702.4	6,822.7
Energy Efficiency	6.7	29.7	6.7	29.7
Total	**139,478.7**	**148,438.0**	**128,104.2**	**131,376.8**

Spring Supply Offered and Cleared Comparison Trend

	Offered (ZRC)		Cleared (ZRC)	
Planning Resource	Spring 2024	Spring 2025	Spring 2024	Spring 2025
Generation	119,254.7	121,303.8	110,195.8	113,091.4
External Resources	3,794.1	3,481.8	3,409.1	3,406.5
Behind the Meter Generation	4,096.4	4,201.6	4,058.9	4,180.5
Demand Resources	7,282.9	7602.9	6,720.0	7,087.2
Energy Efficiency	5.3	25.0	5.3	25.0
Total	**134,433.4**	**136,615.1**	**124,389.1**	**127,790.6**

Zone 5 Supply Offered and Cleared Comparison Trend

	Offered (ZRC)				Cleared (ZRC)			
Planning Resource	Summer 2024	Fall 2024	Winter 2024-2025	Spring 2025	Summer 2024	Fall 2024	Winter 2024-2025	Spring 2025
Generation	7,139.9	5,414.3	5,864.9	5,695.9	7,139.9	5,414.3	5,850.2	5,695.9
Behind the Meter Generation	79.9	78.5	77.1	84.0	79.9	78.5	77.1	84.0
Demand Resources	202.5	51.2	43.8	67.2	202.5	51.2	35.3	67.2
Energy Efficiency	0	0	0	0	0	0	0	0
Imports (External & Imports from other zones)	874.7	2,425.8	2,411.9	1,864.1	874.7	2,425.8	2,411.9	1,864.1
Total	**8,297.0**	**7,969.8**	**8,397.7**	**7,711.2**	**8,297.0**	**7,969.8**	**8,374.5**	**7,711.2**

Historical Summer Auction Clearing Price Comparison

PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs
2015-2016	$3.48			$150.00	$3.48			$3.29		N/A	N/A
2016-2017	$19.72	$72.00						$2.99			N/A
2017-2018	$1.50										N/A
2018-2019	$1.00	$10.00									N/A
2019-2020	$2.99						$24.30	$2.99			
2020-2021	$5.00						$257.53	$4.75	$6.88	$4.75	$4.89-$5.00
2021-2022	$5.00							$0.01			$2.78-$5.00
2022-2023	$236.66							$2.88			$2.88-236.66
Summer 2023	$10.00										
Summer 2024	$30.00										

- Auction Clearing Prices shown in $/MW-Day
- Conduct Threshold is 10% of Cost of New Entry (CONE) and applies to all seasons.

Fall Auction Clearing Price Comparison

PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs
Fall 2023	$15.00								$59.21	$15.00	
Fall 2024	$15.00				$719.81	$15.00					
IMM Conduct Threshold	34.12	33.35	32.22	33.27	36.09	32.97	34.83	31.18	30.91	30.76	36.09
Cost of New Entry (Daily)	341.21	333.51	322.19	332.70	360.89	329.70	348.32	311.81	309.05	307.57	360.89
Cost of New Entry (Annual)	124,541	121, 731	117,600	121,434	131,725	120,340	127,135	113,810	112,804	112,263	131,725

- There was price separation in the fall for Zone 5 since it did not have sufficient supply within the zone to meet its local clearing requirement
- Auction Clearing Prices shown in $/MW-Day
- Conduct Threshold is 10% of Daily Cost of New Entry (CONE) and applies to all seasons
- For Zone 5, there were 183 shortage-days (fall and spring); ACP is Annual CONE / # of shortage-days: 131,725 / 183 = $719.81

Winter Auction Clearing Price Comparison

PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs
Winter 2023-24	$2.00								$18.88	$2.00	
Winter 2024-25	$0.75										

- Auction Clearing Prices shown in $/MW-Day
- Conduct Threshold is 10% of Cost of New Entry (CONE) and applies to all seasons

Spring Auction Clearing Price Comparison

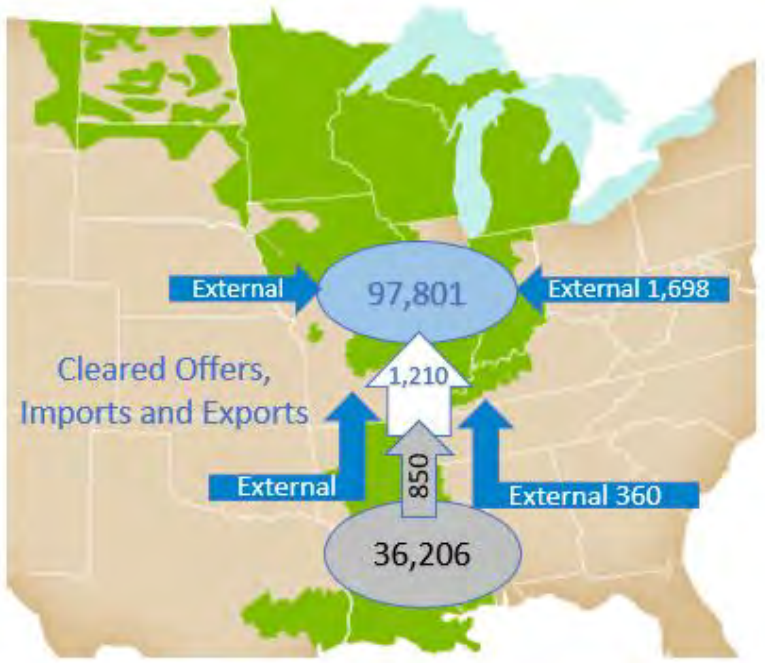
PY	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Zone 9	Zone 10	ERZs
Spring 2024	$10.00										
Spring 2025	$34.10				$719.81	$34.10					

- There was price separation in the Spring for Zone 5 since it did not have sufficient supply within the zone to meet its local clearing requirement
- Auction Clearing Prices shown in $/MW-Day
- Conduct Threshold is 10% of Cost of New Entry (CONE) and applies to all seasons

Summer 2024
Offered Capacity & PRMR (MW)



Summer 2024
Cleared Capacity, Imports & Exports (MW)



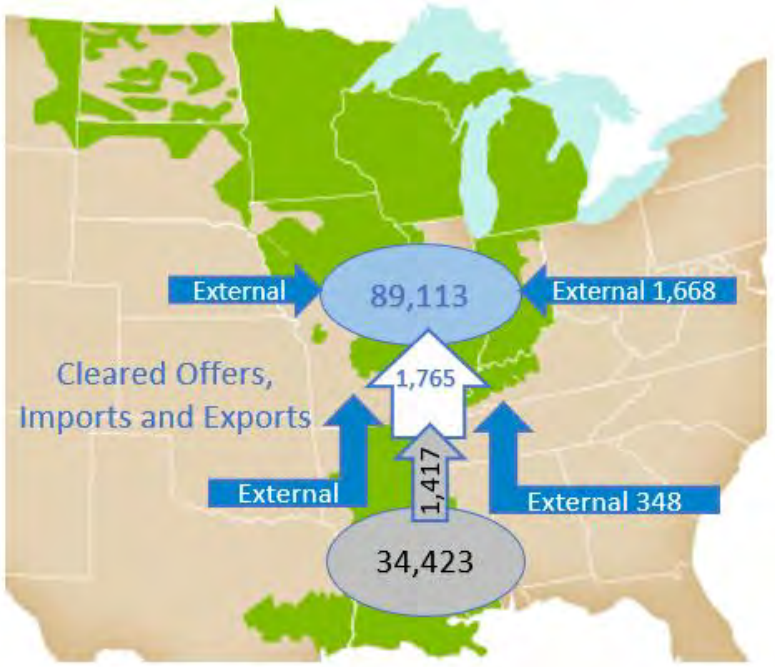
PRMR: Planning Reserve Margin Requirement
Offers includes Fixed Resource Adequacy Plan (FRAP), Self-scheduled and price sensitive offers

04/26/2024: MISO Planning Resource Auction (PRA) for Planning Year 2024-2025 Results Posting

Fall 2024
Offered Capacity & PRMR (MW)



Fall 2024
Cleared Capacity, Imports & Exports (MW)

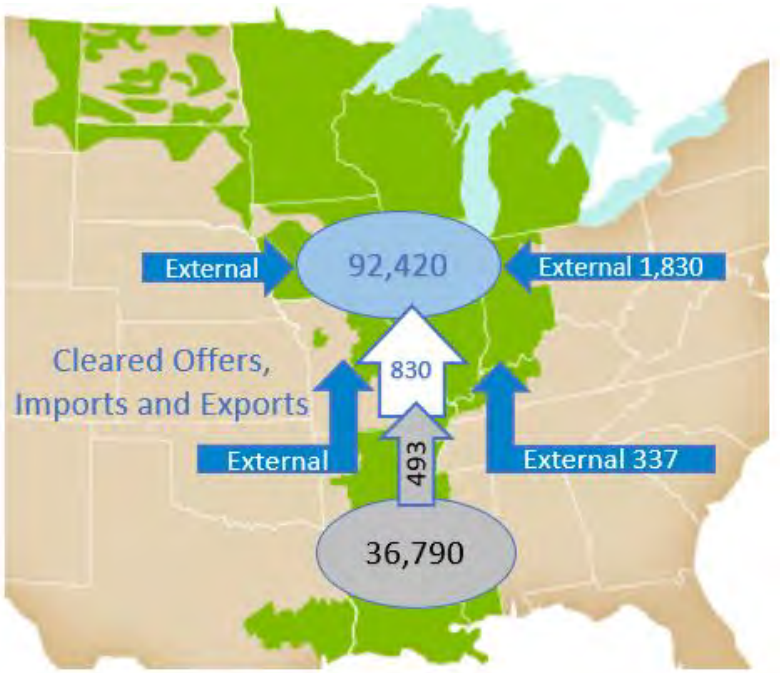


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04/26/2024: MISO Planning Resource Auction (PRA) for Planning Year 2024-2025 Results Posting

Winter 2024/25
Offered Capacity & PRMR (MW)



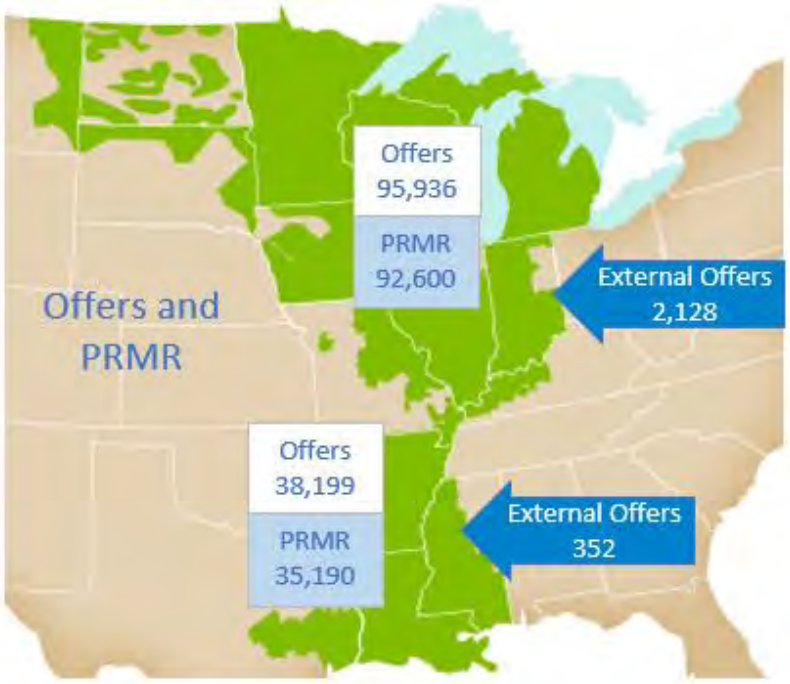
Winter 2024/25
Cleared Capacity, Imports & Exports (MW)



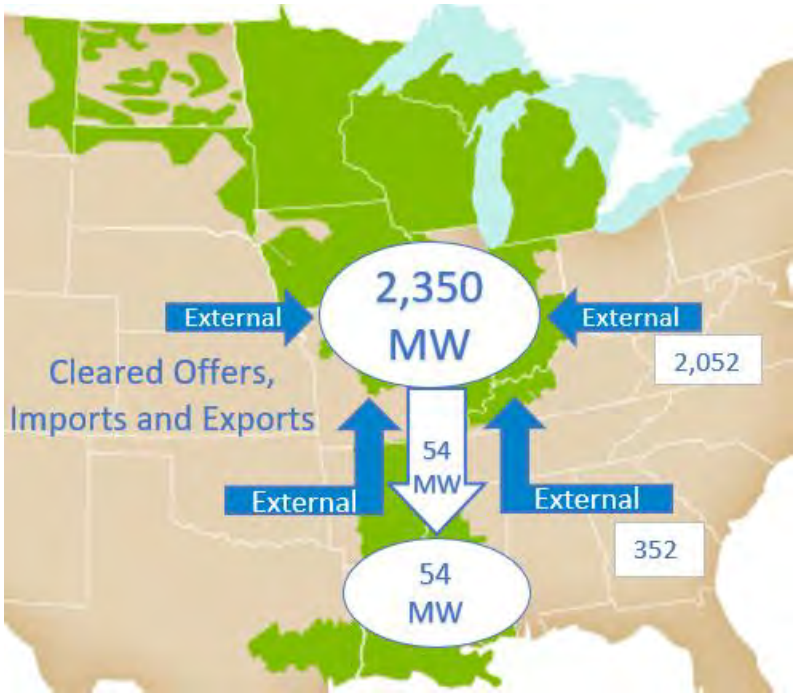
PRMR: Planning Reserve Margin Requirement
Offers includes Fixed Resource Adequacy Plan (FRAP), Self-scheduled and price sensitive offers

04/26/2024: MISO Planning Resource Auction (PRA) for Planning Year 2024-2025 Results Posting

Spring 2025
Offered Capacity & PRMR (MW)



Spring 2025
Cleared Capacity, Imports & Exports (MW)



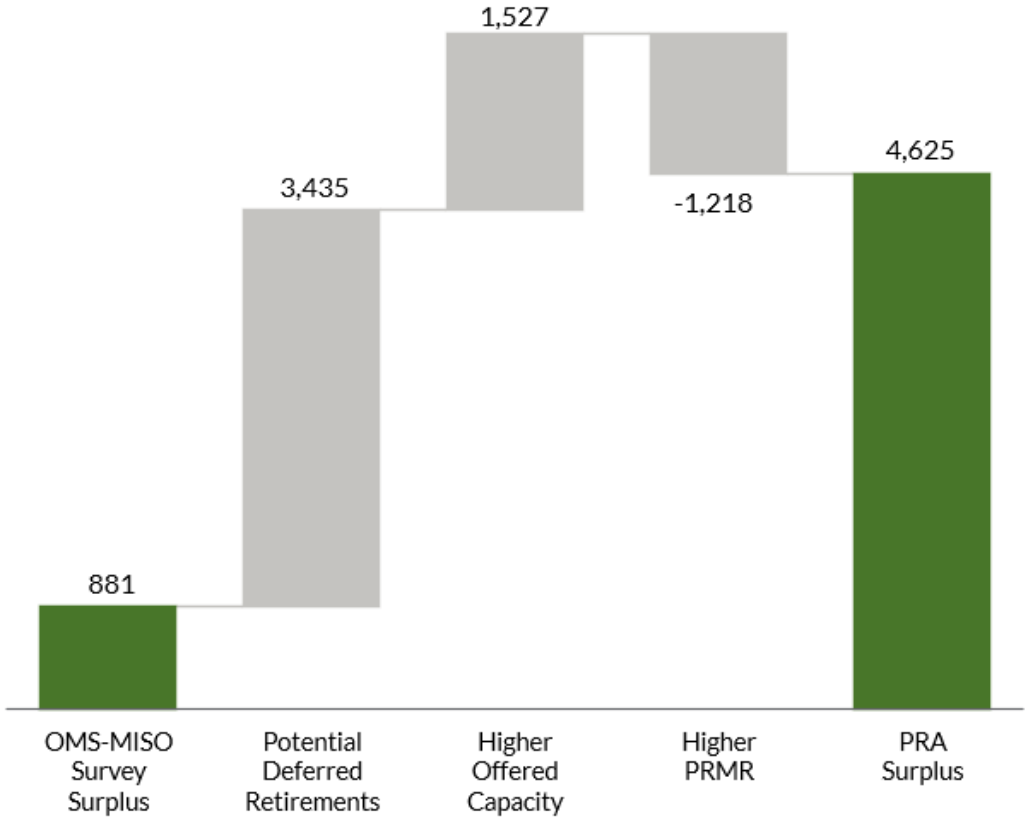
PRMR: Planning Reserve Margin Requirement
Offers includes Fixed Resource Adequacy Plan (FRAP), Self-scheduled and price sensitive offers

04/26/2024: MISO Planning Resource Auction (PRA) for Planning Year 2024-2025 Results Posting

2024 PRA showed a higher surplus relative to the 2023 OMS-MISO survey projection, driven primarily by deferred retirements

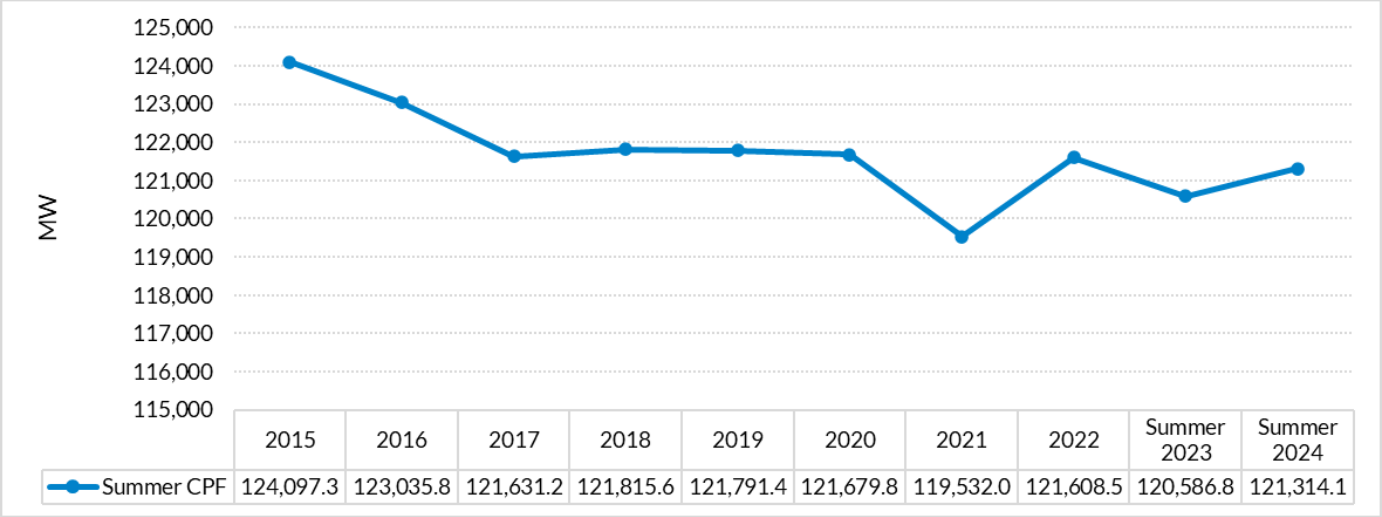
Summer 2024 PRA outcomes vs. 2023 OMS-Survey results

- 3.4 of the 3.5 GW of potential deferred retirement participated in the PRA
- Resources offered in the PRA at 1.5 GW higher than projected in the OMS-MISO Survey
- 1.2 GW higher PRMR MISO-wide because of a higher PRM % than forecasted in the 2023 survey (9% versus 7.9%)

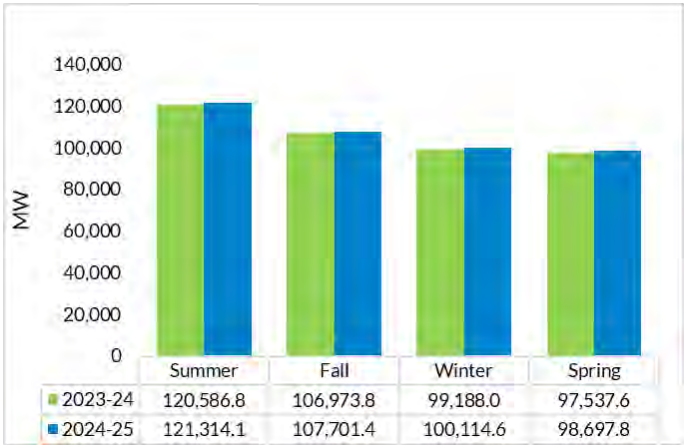


Coincident Peak Forecast

Year over year the Summer CPF (+0.7 GW), PRM (+1.6%) and PRMR (+3.2 GW) are higher.

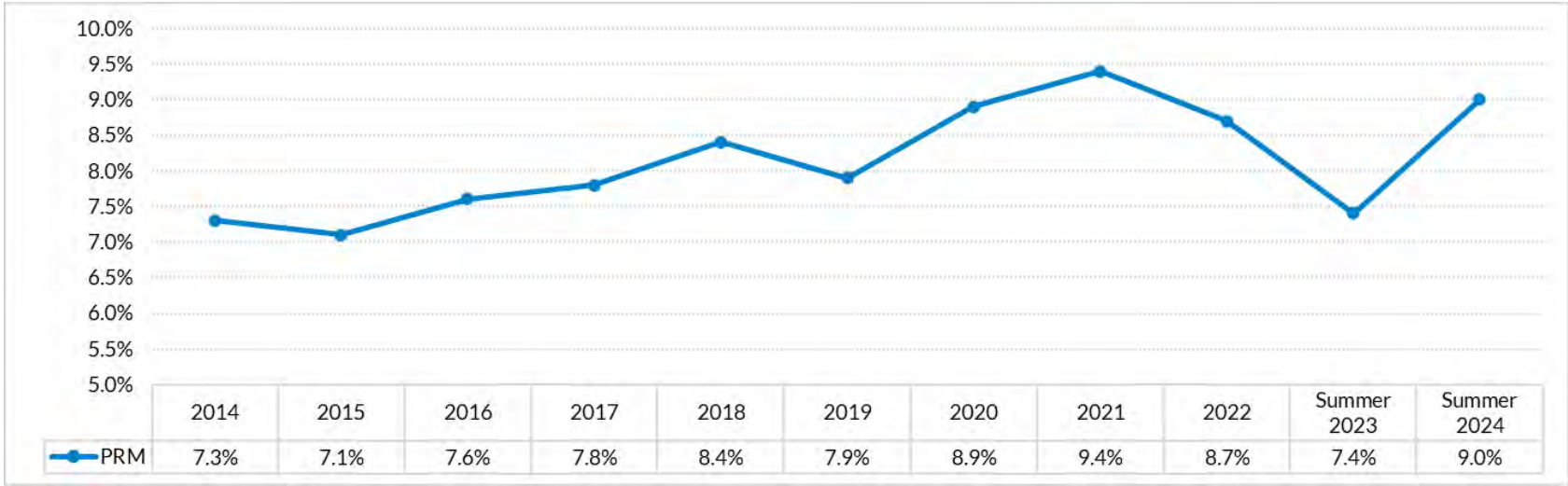


	2015	2016	2017	2018	2019	2020	2021	2022	Summer 2023	Summer 2024
Summer CPF	124,097.3	123,035.8	121,631.2	121,815.6	121,791.4	121,679.8	119,532.0	121,608.5	120,586.8	121,314.1

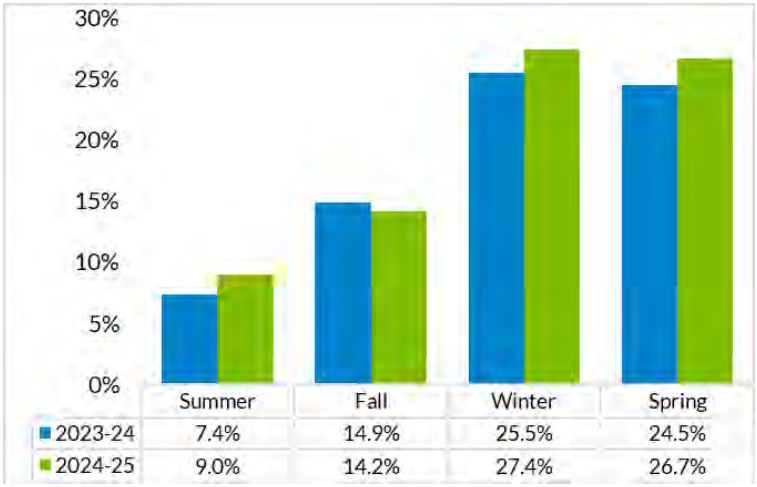


	Summer	Fall	Winter	Spring
2023-24	120,586.8	106,973.8	99,188.0	97,537.6
2024-25	121,314.1	107,701.4	100,114.6	98,697.8

Planning Reserve Margin (%)

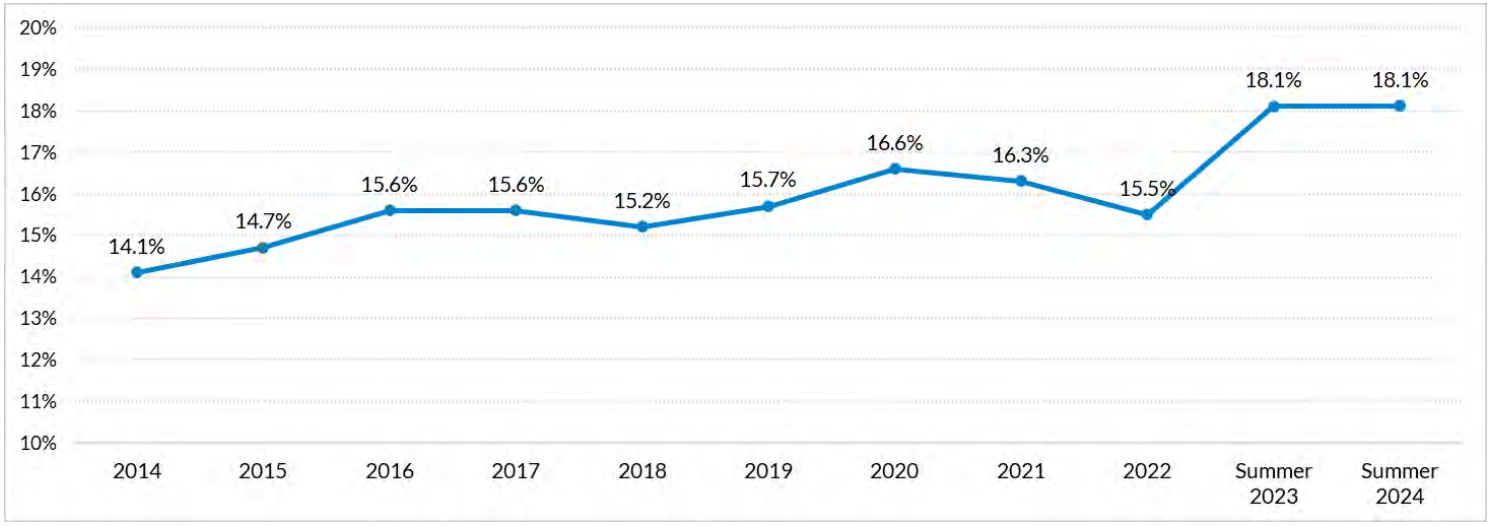


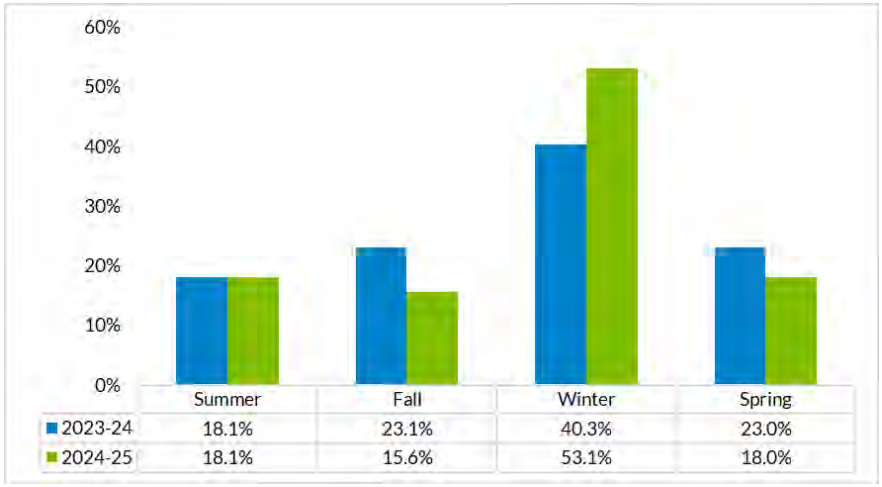
	2014	2015	2016	2017	2018	2019	2020	2021	2022	Summer 2023	Summer 2024
PRM	7.3%	7.1%	7.6%	7.8%	8.4%	7.9%	8.9%	9.4%	8.7%	7.4%	9.0%



	Summer	Fall	Winter	Spring
2023-24	7.4%	14.9%	25.5%	24.5%
2024-25	9.0%	14.2%	27.4%	26.7%

Wind Effective Load Carrying Capacity (%)



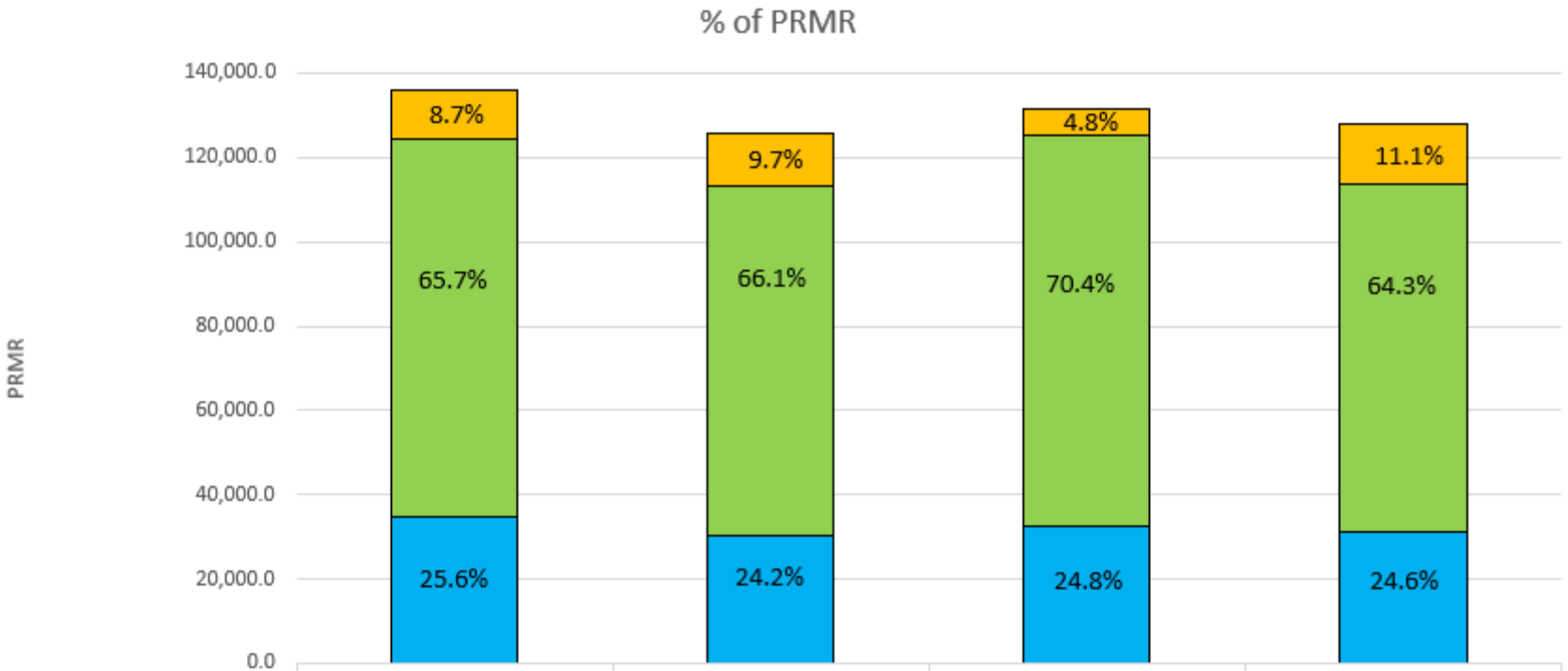


	Summer	Fall	Winter	Spring
2023-24	18.1%	23.1%	40.3%	23.0%
2024-25	18.1%	15.6%	53.1%	18.0%

- No change to wind or solar accreditation methodology from previous years.
- Methodology applied on a seasonal basis.
- Wind ELCC and new solar capacity is established in the LOLE Study
- New solar
  - summer, fall, spring 50%
  - winter 5%

ELCC: Effective Load Carrying Capability LOLE: Loss of Load Expectation

2024-2025 Seasonal Resource Adequacy Requirements are fulfilled similarly across all four seasons



	Summer 2024	Fall 2024	Winter 2024-25	Spring 2025
Cleared Non-Self Scheduled	11,800.8	12,184.1	6,323.9	14,181.5
Self Scheduled	89,408.1	83,023.4	92,459.0	82,219.3
FRAP	34,855.5	30,343.9	32,593.9	31,389.8

PRMR: Planning Reserve Margin Requirement

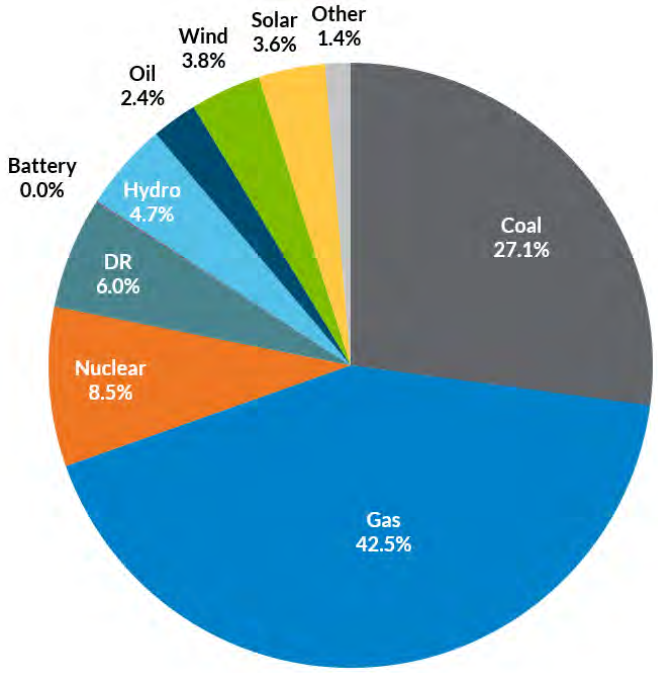
Although conventional generation still comprises most of the capacity, wind and solar continue to grow

- 4.9 GW of solar cleared this year's auction, an increase of 61% from Planning Year 2023-24 (3.0 GW)
- 5.2 GW of wind cleared this year, an increase of 4% compared to last year (5.0 GW)



Winter PRMR is 4.7 GW (3.4%) lower than the summer. There were less thermal, hydro and solar resources and significantly more wind to meet PRMR in the Winter versus the Summer

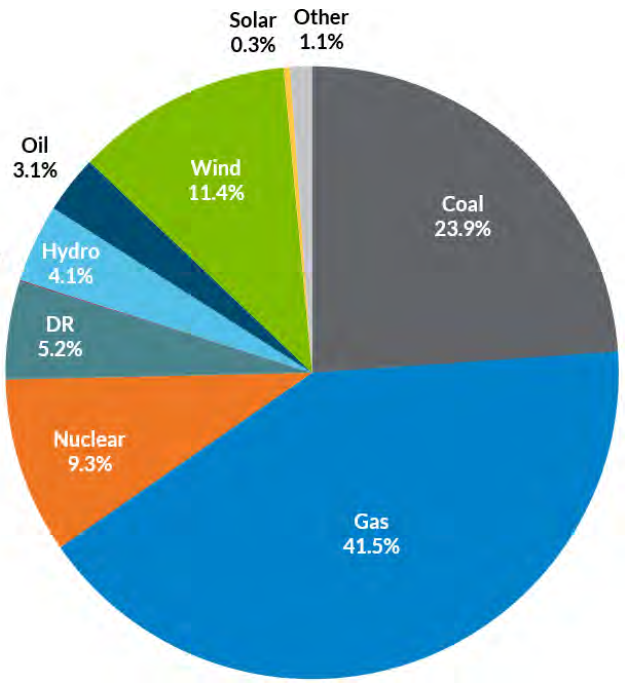
Summer 2024



MISO-wide

Cleared ZRC	Summer 2024	Winter 2024-25	Difference
Coal	36,894.8	31,391.7	5,503.1
Gas	57,799.3	54,460.7	3,338.6
Nuclear	11,594.6	12,218.0	-623.4
DR	8,109.4	6,822.7	1,286.7
Battery	59.0	59.1	-0.1
EE	22.5	29.7	-7.2
Hydro	6,427.1	5,398.9	1,028.2
Oil	3,316.6	4,010.9	-694.3
Wind	5,150.0	15,034.7	-9,884.7
Solar	4,851.7	445.0	4,406.7
Misc	1,839.4	1,505.4	334.0
PRMR	136,064.4	131,376.8	4,687.6

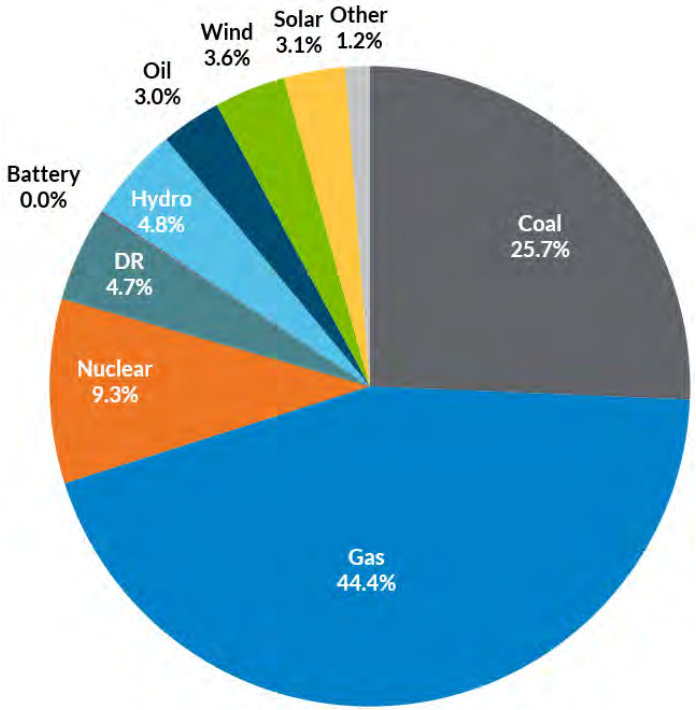
Winter 2024-25



PRMR: Planning Reserve Margin Requirement

Fall 2024 and Spring 2025 - Cleared ZRCs and PRMR

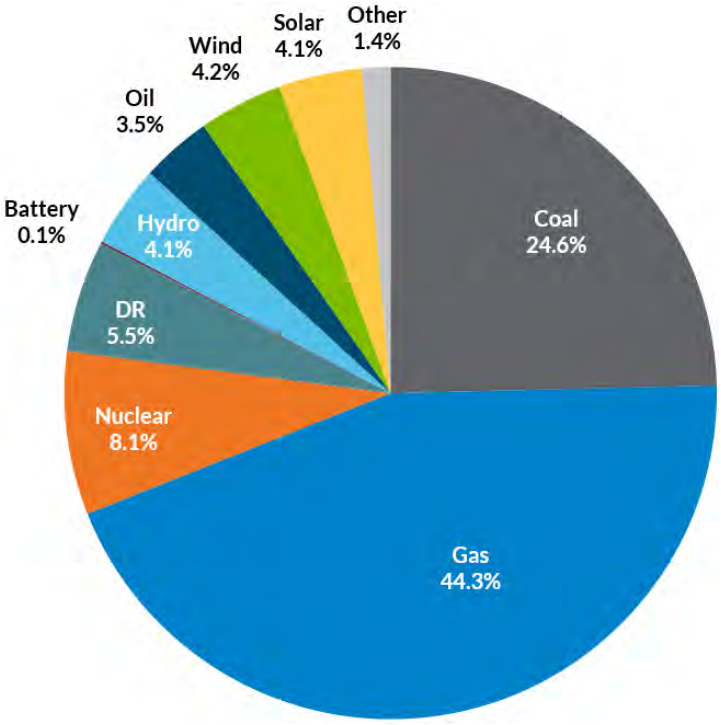
Fall 2024



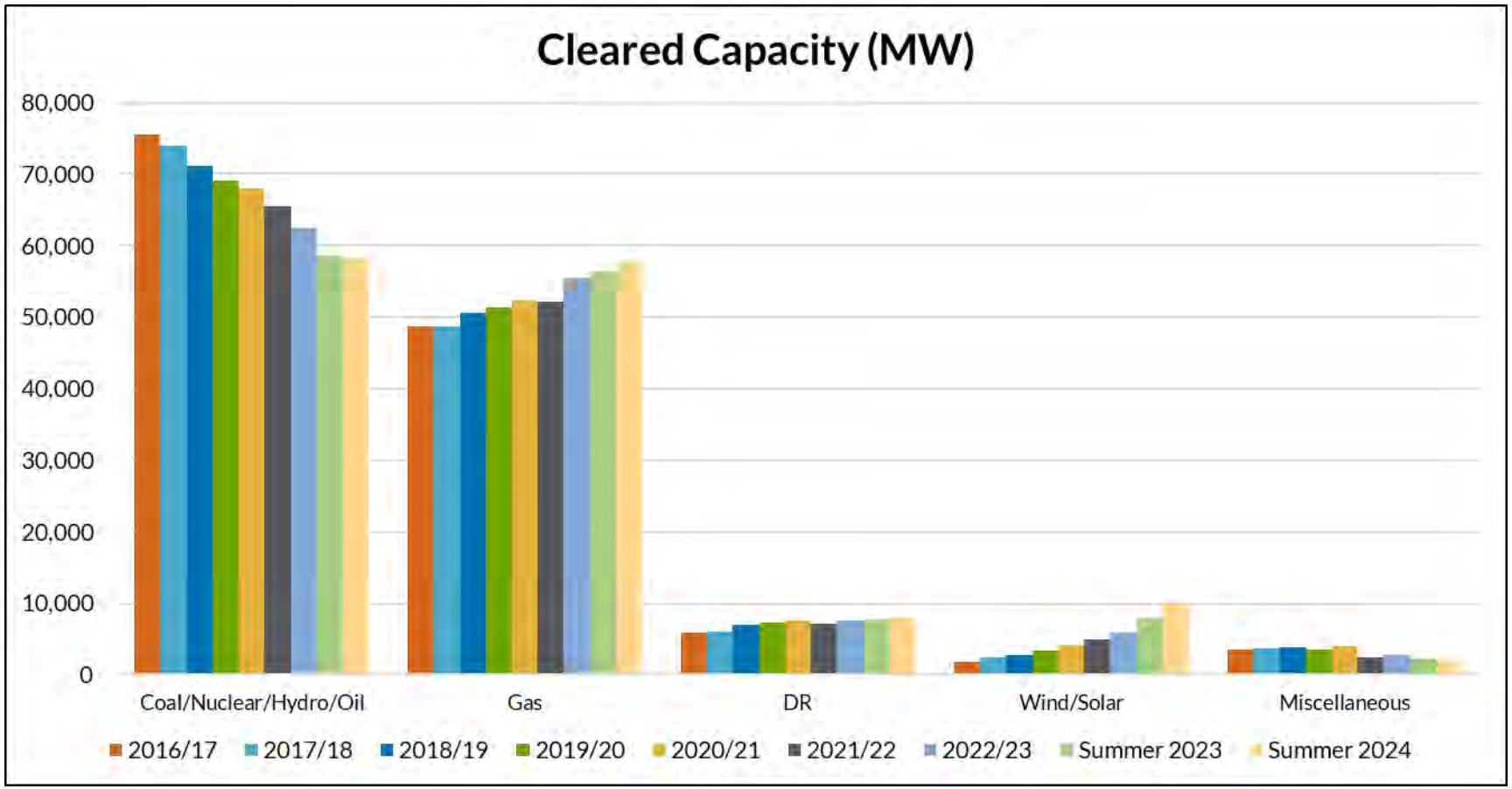
MISO-Wide

Cleared ZRC	Fall 2024	Spring 2025
Coal	32,221.7	31,469.1
Gas	55,793.3	56,667.0
Nuclear	11,682.3	10,338.7
DR	5,957.5	7,087.2
Battery	58.8	112.3
EE	22.5	25.0
Hydro	6,037.8	5,215.6
Oil	3,819.2	4,464.0
Wind	4,521.8	5,322.7
Solar	3,894.4	5,282.1
Misc	1,542.1	1,807.0
PRMR	125,551.4	127,790.6

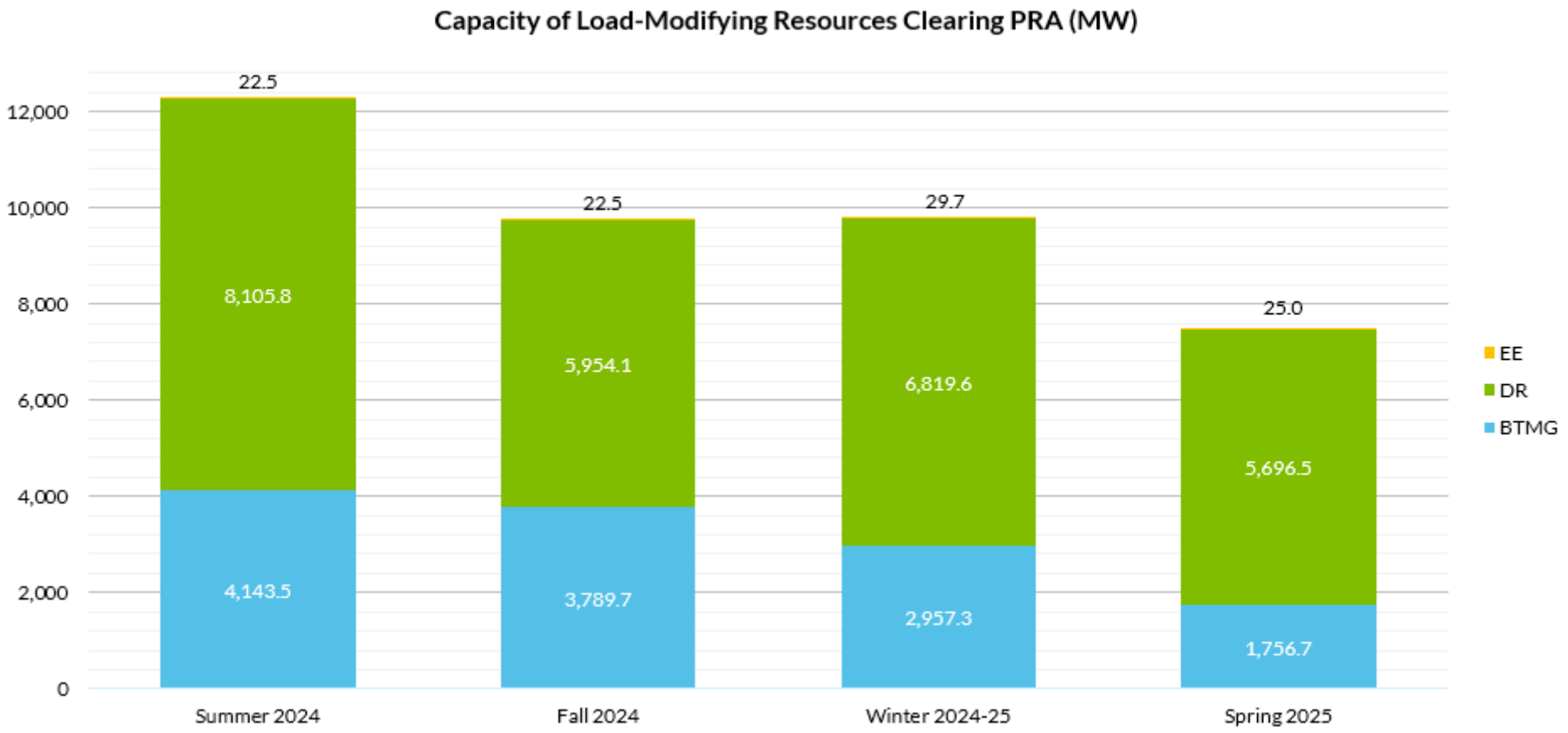
Spring 2025



The planning resource mix shows the continuation of a multi-year trend towards less coal/nuclear/hydro/oil and increased gas and non-conventional resources

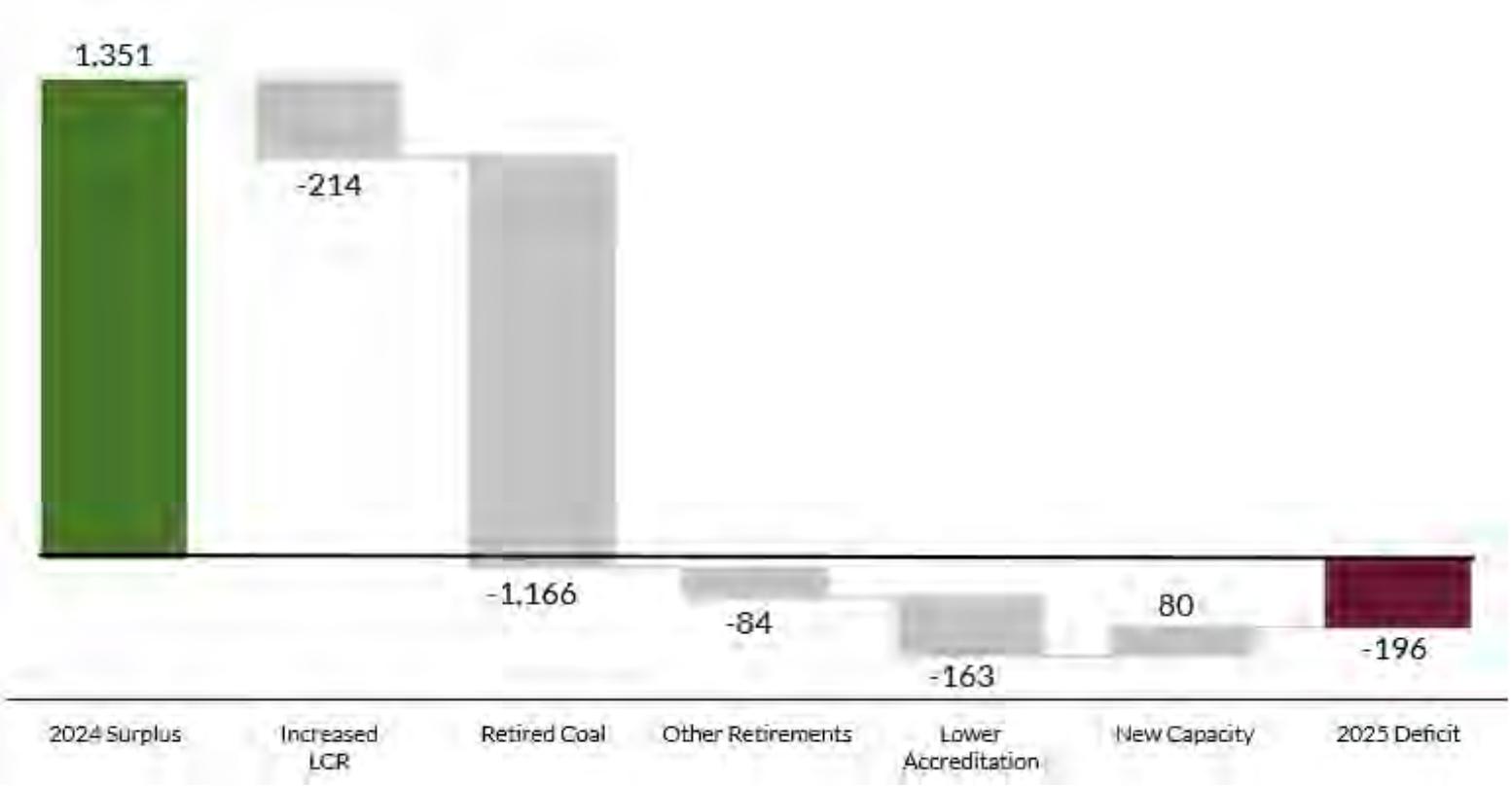


2024-2025 Seasonally Cleared Load Modifying Resources Comparison



A combination of higher Local Clearing Requirement and reduced capacity contributed to Zone 5 deficiency in the spring

Zone 5 Spring 2025 Capacity Changes Year-Over-Year



PO: Planned Outage

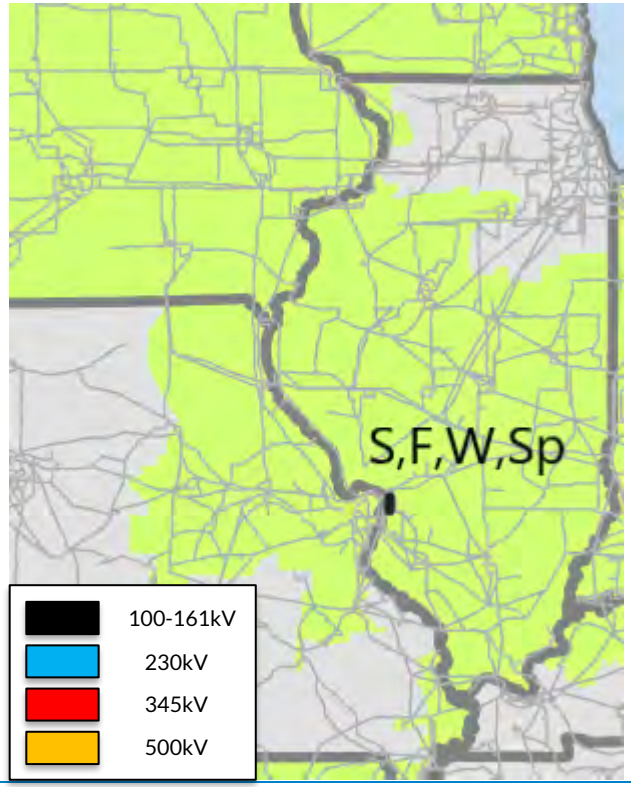
Zone 5 Local Clearing Requirement

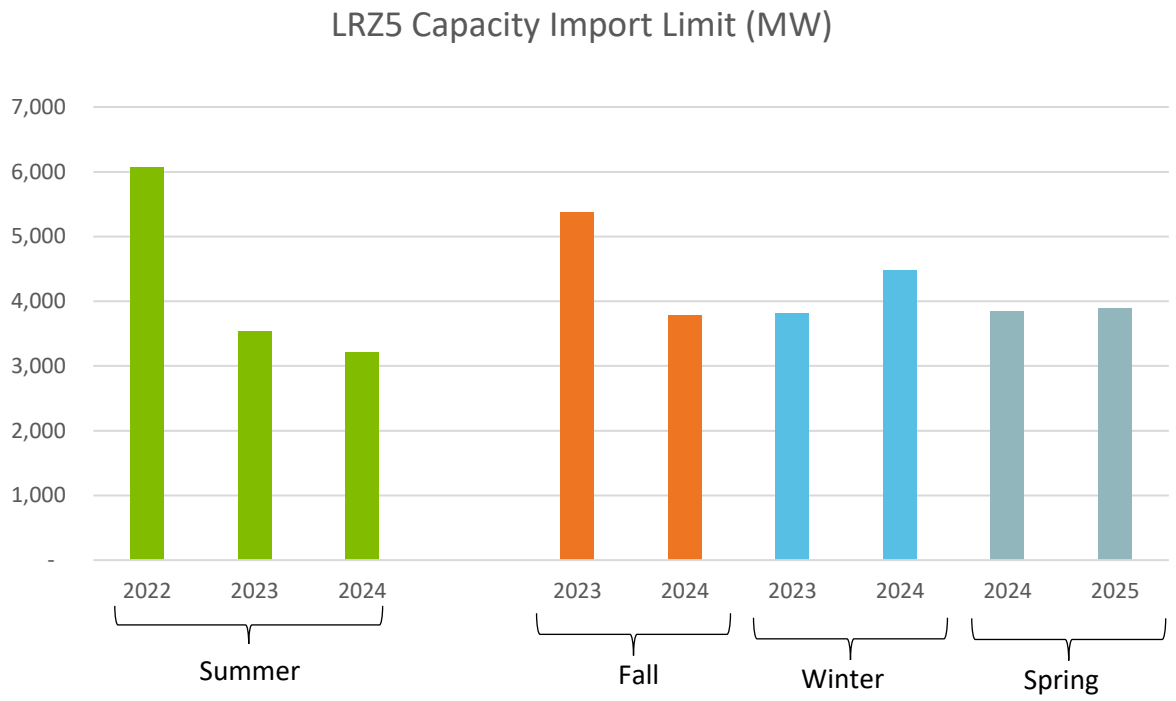
		Summer		Difference		Fall		Difference	
		2024	2023	MW	%	2024	2023	MW	%
(A)	Zonal Coincident Peak Forecast (ZCPF)	7,532.3	7,450.3			6,911.9	6,591.9		
(B)	Transmission Loss (TL) for ZCPF (MW)	147.9	130.7			168.2	115.2		
(C)=(A)+(B)	LRZ Peak Demand	7,680.2	7,581.0	99.2	1.3%	7,080.1	6,707.1	373.0	5.6%
(D)	LRR UCAP/LRZ Peak Demand from LOLE	1.331	1.333			1.441	1.452		
(E)=(C)*(D)	Local Reliability Requirement (LRR)	10,222.3	10,105.5	116.9	1.2%	10,202.4	9,738.7	463.7	4.8%
(F)	Zonal Import Ability (ZIA)	3,208.0	3,576.0	(368.0)	-10.3%	3,786.0	5,380.0	(1,594.0)	-29.6%
(G)	Controllable Exports	0.0	0.0			0.0	0.0		
(H)=(E)-(F)-(G)	Local Clearing Requirement (LCR)	7,014.3	6,529.5	484.9	7.4%	6,416.4	4,358.7	2,057.7	47.2%

		Winter		Difference		Spring		Difference	
		2024-25	2023-24	MW	%	2025	2024	MW	%
(A)	Zonal Coincident Peak Forecast (ZCPF)	6,397.0	6,483.2			6,023.0	5,921.4		
(B)	Transmission Loss (TL) for ZCPF (MW)	247.8	188.3			117.6	109.8		
(C)=(A)+(B)	LRZ Peak Demand	6,644.8	6,671.5	(26.7)	-0.4%	6,140.6	6,031.2	109.4	1.8%
(D)	LRR UCAP/LRZ Peak Demand from LOLE	1.285	1.474			1.618	1.610		
(E)=(C)*(D)	Local Reliability Requirement (LRR)	8,538.6	9,833.8	(1,295.2)	-13.2%	9,935.5	9,710.2	225.3	2.3%
(F)	Zonal Import Ability (ZIA)	4,477.0	3,811.0	666.0	17.5%	3,892.0	3,881.0	11.0	0.3%
(G)	Controllable Exports	0.0	0.0			0.0	0.0		
(H)=(E)-(F)-(G)	Local Clearing Requirement (LCR)	4,061.6	6,022.8	(1,961.2)	-32.6%	6,043.5	5,829.2	214.3	3.7%

Capacity Import Limits
Zone 5: Missouri

LRZ5	Monitored Element	Monitored Element Rating	Contingency	CIL
Summer 2024	Moro - Miles 138 kV	305 MVA	Roxford - Moro 345 kV	3208
Fall 2024	Moro - Miles 138 kV	305 MVA	Roxford - Moro 345 kV	3786
Winter 2024/25	Moro - Miles 138 kV	329 MVA	Roxford - Moro 345 kV	4477
Spring 2025	Moro - Miles 138 kV	305 MVA	Roxford - Moro 345 kV	3892





From 10/17/23 LOLEWG: Item 04 PY 2024-25 Final CIL-CEL Results Slide 11

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https://help.misoenergy.org/

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

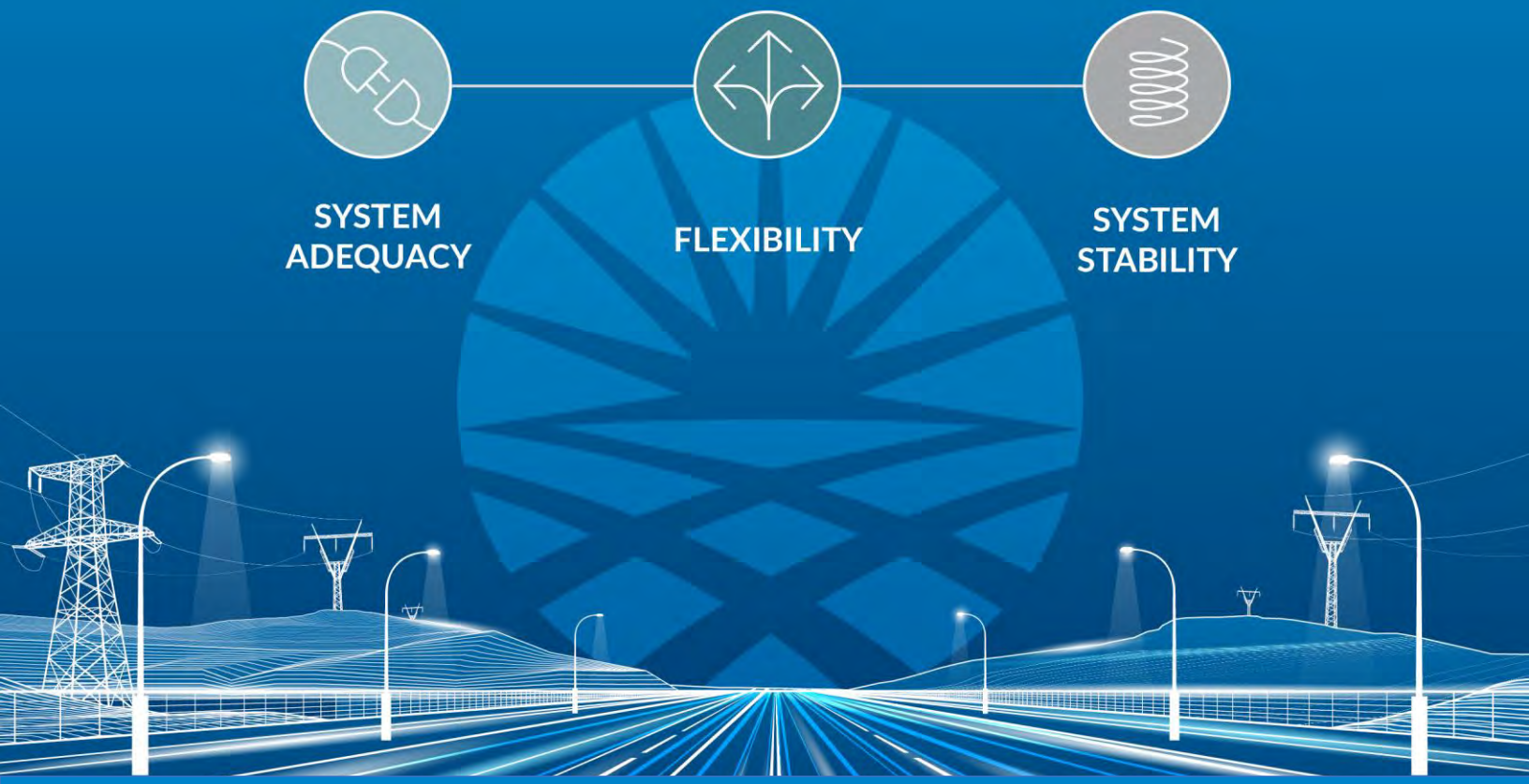
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

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

Exhibit 85
MISO Attributes Roadmap

Attributes Roadmap

A RELIABILITY IMPERATIVE REPORT



DECEMBER 2023

Highlights

- The evolving energy landscape requires MISO and the industry to understand the increasing complexity of the transitioning system and proactively adapt to increasing risk and changing system conditions

- MISO's 2023 analysis highlights the need for market reforms and new requirements to ensure the sufficiency of three priority attributes where near-term risk is most acute: system adequacy, flexibility, and system stability

- The *Attribute Roadmap* recommends advancing a combination of current and new proposals as well as providing ongoing attributes visibility through regular reporting

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Table of Contents

Executive Summary 3

Project Introduction and Approach 6

System Adequacy 9

Roadmap: Further modernize the resource adequacy construct 17

Flexibility 23

Roadmap: Focus market signals on emerging flexibility needs 29

Roadmap: Enable emerging resources' potential 32

System Stability 35

Roadmap: Require capabilities to strengthen the grid 44

Acknowledgments 51

Version Number	Purpose / Change	Date
1.0	Initial posting.	December 2023
1.1	Updated with hyperlinks between the *Technical Appendix* and the *Attributes Roadmap* and correction of minor typos per stakeholder feedback.	June 2024

Executive Summary

INTRODUCTION

The *Attributes Roadmap* presents insights and solutions following an in-depth look at the challenges of operating a reliable bulk electric system in a rapidly transforming energy landscape. The generation resource mix is diversifying; the surety of the fuel supply is declining; extreme weather is increasing in intensity and duration; and industrial load growth and electrification trends are poised to disrupt traditional load patterns. These factors create complex challenges for MISO and stakeholders and a shared imperative to urgently act to avoid a looming shortage of necessary system reliability attributes and ensure electricity is delivered every hour of every day to the 45 million people in the MISO region.

No single resource provides every needed system attribute. The needs of the system have always been met by a fleet of diverse resources operated in a manner that most efficiently meets the system needs. Preparing for the energy transition requires an improved understanding of the reliability attributes of the bulk electric system and the advancement of urgent market reforms and requirements to meet the changing system needs.

In 2023, MISO designed and completed a foundational analysis of the system reliability attributes. The analysis focused on three priority attributes where risk to the MISO system is most acute**: system adequacy, flexibility, system stability**, and their near-term risk factors (Figure 1). MISO developed recommended approaches and solutions based on input from various expert sources, including MISO's internal subject matter experts and past analyses, MISO stakeholders, external industry research, and leading industry experts.

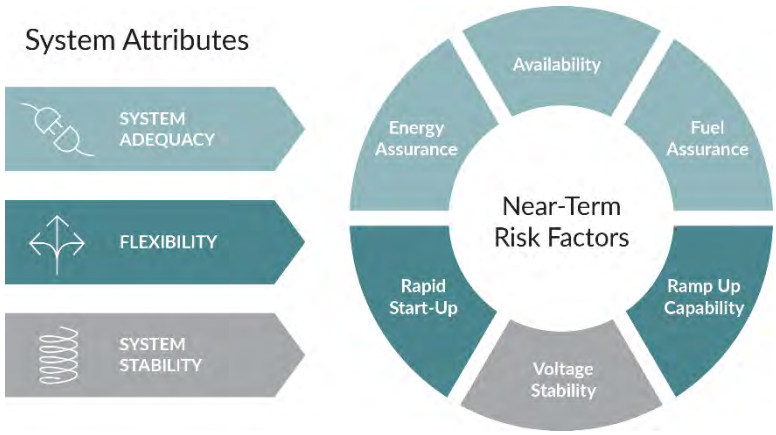


Figure 1: Three priority system reliability attributes and their near-term risk factor focus areas

INSIGHTS AND SOLUTIONS

To meet the rapidly evolving needs of the bulk electric system, urgent action is needed to advance a targeted portfolio of market reforms and system requirements, and to provide ongoing attributes visibility through regular reporting. In summary:

SYSTEM ADEQUACY refers to the ability to meet electric load requirements during periods of high risk. MISO focused on the near-term risk factors of availability, energy assurance, and fuel assurance.

- Approach: Best addressed in the planning horizon and served through capacity requirements, capacity accreditation (valuation), and market solutions within the seasonal resource adequacy construct where a diverse range of generation resources can contribute to meeting demand and

reserve requirements. Additionally, evolved coordination is needed between MISO's resource adequacy assessments and MISO state and member planning processes.

- Recommendations: MISO recommends a continued focus on one market clearing product (capacity), and further modernizing the resource adequacy construct to address emerging attribute-related risk factors through improved risk modeling, capacity accreditation, and capacity market qualification requirements. Additionally, MISO recommends providing visibility into future regional system adequacy needs and capabilities through improved forecasting and reporting.

FLEXIBILITY is the extent to which a power system can adjust electric production or consumption in response to changing system conditions. MISO focused on the near-term risk factors of rapid start-up and ramp-up capability.

- Approach: Best addressed in the operating timeframe and served through market solutions where resources can compete to meet the increasingly variable and uncertain real-time operational needs of the system.
- Recommendation: MISO recommends advancing two strategic objectives to address this attribute: (1) focus market signals on emerging flexibility needs through expanded and new ancillary service products, and (2) expand the fleet of qualifying resources able to provide flexibility by enhancing market systems and reforming resource participation models to enable emerging technologies to fully participate.

SYSTEM STABILITY is the ability to remain in a state of operating equilibrium under normal operating conditions and to also recover from disturbances. MISO focused on the nearest-term risk factor of voltage stability.

- Approach: Best addressed initially through requirements and technology standards and a multistep approach to require capabilities from resources to support grid stability.
- Recommendation: MISO recommends requirements for inverter-based resource controls as part of the resource interconnection process and incentives for critical reliability capabilities as needed.

The *Attributes Roadmap* includes current and new proposals to ensure the sufficiency of the priority system reliability attributes with approximate project relationship and timing (Figure 2). The report discusses each of these recommendations in detail as well as the analysis and research that supports the recommendations.

NEXT STEPS

The attributes insights and solutions will further inform the region's Reliability Imperative priorities. MISO's next step will be to integrate the recommendations into its processes with stakeholder engagement throughout. In addition, MISO will continue to monitor the efficacy of planned and implemented solutions, study additional system attributes, and consider solutions beyond this recommendation.

Timely collaboration is needed between MISO, its stakeholders, and the broader industry to continue this mission-critical work and ensure the region is prepared to reliably navigate the energy transition.

Find the latest project status on MISO's Dashboard for "Identification of Sufficient Reliability Attributes RASC – 2022-1." Ongoing system attributes work will be coordinated through the MISO Stakeholder Resource Adequacy Subcommittee.

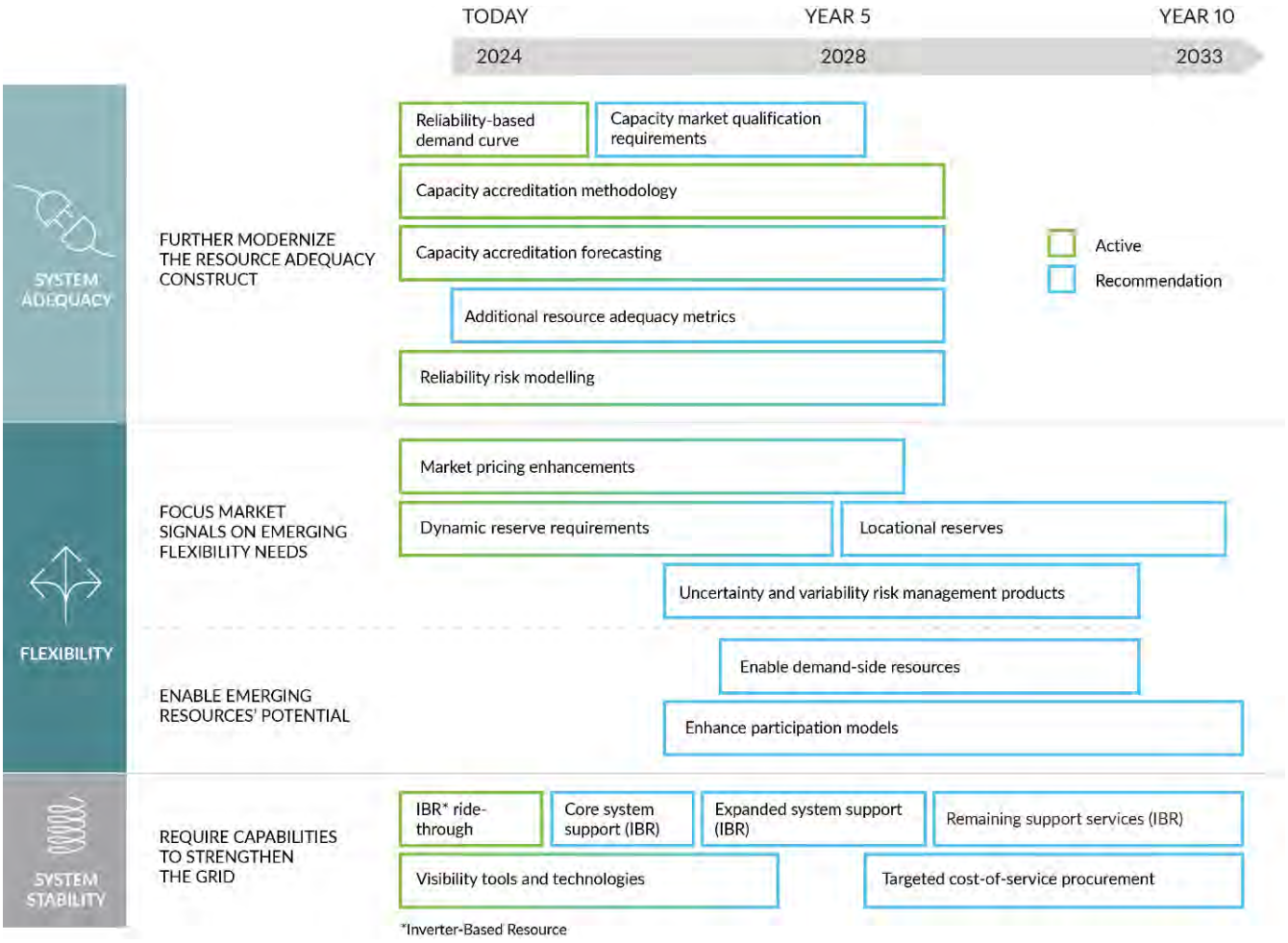


Figure 2: Hypothesis for attributes solution roadmap with approximate timing for projects currently underway (active) and proposed future projects (recommendation). The *Attributes Roadmap* discusses each recommendation in detail as well as the analysis and supporting research.

Project Introduction and Approach

System reliability attributes are characteristics of the bulk electric system. A wide range of attributes is needed to ensure reliability and support the region's affordability and sustainability objectives. Importantly, no single generating resource provides every needed system attribute.[1] The foundational needs of the system have always been met by a fleet of diverse resources operated in a manner that most efficiently meets system needs.

As the system transforms, strategic assessments by MISO and other industry experts conclude that system reliability attributes will need to be increasingly studied, measured, incentivized, and required for the bulk electric system to maintain its expected levels of reliability.

MAJOR DRIVERS OF CHANGE INTRODUCE NEW AND SHIFTING SYSTEM RISK

Major industry trends are simultaneously changing the conditions of the system, for example:

- New generation and load resources coming online often do not have the same characteristics as the resources they are replacing, introducing the potential risk that the needs of the system will not be met by the transitioning fleet.
- Increased impacts from severe weather creates major challenges in managing transmission congestion, high rates of correlated forced outages, and extended periods of high demand.
- Demand for electricity is increasing to meet new needs (e.g., the information economy, efforts to rebuild domestic supply changes, and electrification) and disrupting traditional load patterns.

See MISO's *Response to the Reliability Imperative* for a more detailed analysis of trends and drivers of change in the MISO region.

PAST STUDIES INFORM PRIORITIZATION AND APPROACH

The attributes project was informed by previous MISO studies assessing the region's changing risk profile and exploring the reliability impact of the major drivers. This work includes:

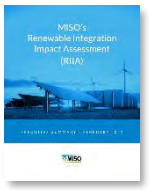
Markets of the Future: Illustrated how and when MISO's existing market structures will need to evolve to accommodate the profound changes that are occurring in the energy sector. The needs were presented in four broad categories: (1) Uncertainty and Variability; (2) Resource Models and Capabilities; (3) Location; and (4) Coordination. This report helped establish the foundation for the attributes work.



MISO Futures: Utilized a range of economic, policy, and technological inputs to develop three future scenarios that "bookend" what the region's resource mix might look like in 20 years. The attributes team used the recently refreshed Future 2A forecasted resource portfolios to perform the forward looking five-year and 10-year analysis.



[1] EPRI, Energy Supply Reference Card, 2023 Version.



[Renewable Integration Impact Assessment (RIIA)]: Assessed the impacts of integrating increasingly higher levels of renewables into the MISO system. This assessment steered the attributes project in many ways, including the key finding that voltage stability and inverter-based converter stability are among the first system stability related challenges the MISO system will likely face.



[Regional Resource Assessment (RRA):] Recurring study based on the plans and goals that MISO members have publicly announced for their generation resources. This year's attributes analysis built upon the flexibility assessments of net load variability and uncertainty changes originally presented within the RRA.



[The February (2021) Arctic Event:] Discussed lessons learned from Winter Storm Uri, which affected the MISO region and other parts of the country in February 2021. MISO and its members took emergency actions during the event to prevent more widespread grid failures. The attributes work used Uri as a case study.

EXPLORATION OF THE SOLUTIONS LANDSCAPE

MISO began the process of developing possible solutions to the major questions regarding system adequacy, flexibility, and system stability by soliciting input from expert sources (Figure 3). From these queries, MISO filtered more than 100 possible solutions to the problems proposed.

Many solution options came from MISO's internal experts and past reports. Stakeholder discussions offered ideas, including recommendations for MISO's Independent Market Monitor (IMM). The team reviewed relevant industry research and literature, including work led by the Energy System Integration Group, NERC's Energy Reliability Assessment Task Force, and the Electric Power Research Institute (EPRI). Additionally, MISO reviewed the actions and published analysis of other grid operators, including PJM and ERCOT, the Australian Energy Market Operator, and UK's National Grid Electricity System Operator.

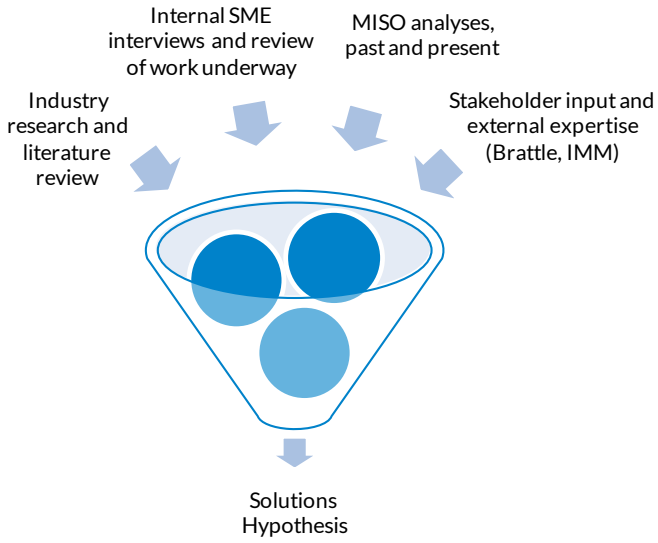


Figure 3: Sources of solutions considered

Solutions exploration and focus was done in consultation with The Brattle Group. MISO engaged Brattle on strategy and risk approaches, evaluation of the solutions for impact and efficiency, and industry expertise on solution implementation outcomes in other regions. Brattle presented its recommendation to the Resource Adequacy Subcommittee (RASC) in October 2023.[2]

[2] Brattle, "MISO Reliability Attributes Solution Space," presented to MISO's Resource Adequacy Subcommittee (RASC), October 4, 2023.

CRITERIA FOR EVALUATING CANDIDATE SOLUTIONS

Solutions were narrowed based on the following evaluation criteria:

TECHNICAL CRITERIA

- ✔ Helps **attract/retain** sufficient resources to provide the target reliability attribute
- ✔ **Operationally utilizes** the resource to provide the attribute

ECONOMIC CRITERIA

- ✔ Promotes **economically efficient investment**
- ✔ Promotes **economic efficient operations and performance**

PROCESS CRITERIA

- ✔ Provides **transparency** and predictability, without excessive complexity
- ✔ Has acceptable **implementation cost and time**

OTHER CONSIDERATIONS

- ✔ **Resource neutrality**
- ✔ Informs **long-term planning** for states and members
- ✔ **Adaptability** to change in policies and market conditions
- ✔ **Compatibility** with existing processes, markets, and policies

MISO applied the quantitative criteria against the initial list of solutions. With the shorter list of solution candidates, quantitative analysis was completed wherever practical to test the working hypotheses.

FOUNDATIONAL ANALYSIS AND SOLUTIONS

This report is divided into three sections, one for each priority attribute: system adequacy, flexibility, and system stability. Each section begins with a definition of the attribute and problem statement, followed by a high-level recap of the foundational analysis and key insights, as presented in the September 2023 and October 2023 attributes workshops. Following that is a directional recommendation of how to approach possible solutions, including what MISO recommends *not* to do. Lastly, each section contains details of the proposed roadmap of solutions, including related work underway at MISO.

MISO conducted foundational analysis for each priority system attribute to guide the solution selection and prioritization. The analysis relied on existing and vetted datasets, methods, and software, which were augmented to meet the specific needs of the study. Generally, the analysis compared a representation of today's system (e.g., planning year 22-23) to forecasted out-year system conditions derived from MISO's Future 2A expansion.[3]

[3] Futures portfolio are based on Scenario 2A in MISO, *MISO Futures Report Series 1A*, November 2023.

System Adequacy

NERC defines adequacy as the "ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements."[4] MISO's attributes team further framed the system adequacy attribute as the ability of a resource portfolio to meet capacity and energy demand for a wide range of system conditions, with the expectation that unserved demand does not exceed a predetermined criteria.

MISO focused the 2023 system adequacy analysis on the risk factors expected to be most acute in the near term: availability, energy assurance, and fuel assurance (Figure 4). Availability is the consistent and predictable ability to call on capacity at the time of need. Energy assurance is the ability of the system to adequately manage and deliver energy supply on a 24 hour, seven days a week basis, especially in the presence of variable-energy or energy-limited resources. Fuel assurance is the ability for resources to access primary or backup fuel for electric power production at the time of need. These aspects of system adequacy are interrelated. For instance, extreme weather can drive widespread performance issues across all three risk factors.



Figure 4: System Adequacy near-term risk factor focus areas

RECENT AND PROPOSED RESOURCE ADEQUACY REFORMS ADDRESS THE FUNDAMENTALS

The modernization of MISO's resource adequacy construct is well-underway with recent and proposed changes to incorporate current industry best practices and address shifting risk. MISO's recently implemented seasonal Planning Resource Auction (PRA) better acknowledges seasonal risks and resource capabilities throughout the year. The current accreditation methodology, approved by the Federal Energy Regulatory Commission (FERC) in 2022, also aligns the accreditation of thermal resources with their availability in the recent highest risk periods.

The proposed next step for resource adequacy reform is to credit all resources using a combination of the Direct Loss of Load (DLOL) method[5] at the class level and the previously defined Resource Adequacy hours[6] at the unit level. Load modifying resources (LMR) and other emergency resources are currently excluded from the proposed accreditation changes (DLOL method), due to their status as emergency only. MISO is working on a parallel initiative for these resources.

When MISO implements these proposed reforms, the fundamental components will be in place to address the energy transition. MISO recommends improvements to the underlying model to fully capture attribute risk.

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[4] NERC, *Glossary of Terms Used in NERC Reliability Standards*, March 2023.

[5] DLOL is an accreditation methodology that examines the contribution of a resource to the system during times of risk, represented by loss of load hours. MISO, *Resource Accreditation White Paper* , November 2023.

[6] FERC. Docket No. ER22-495-002, February 16, 2023.

SYSTEM ADEQUACY REQUIRES EXTENDING LOSS OF LOAD EXPECTATION MODELING

Today, MISO's Loss of Load Expectation (LOLE)[7] modeling incorporates an optimized planned outage schedule and randomly drawn forced outages based on historical unit-level outage data. Additionally, an extreme cold weather outage adder is modeled, which approximates weather-dependent outages using zone-specific, fixed outage profiles based on historical outage data during extreme cold temperatures. As the system's fleet continues to evolve, it is necessary to better understand and quantify the impact on the system risk from weather-related drivers, such as outages related to fuel unavailability, mechanical failure, and a breakdown of gas/electric coordination. To increase visibility into the weather-dependent risk drivers, it is important to explore the impact of fuel and non-fuel related outages on the LOLE framework. It is also key to acknowledge the regional implications of transfer limits between different geographical locations as the resource mix becomes more diverse.

Resource Adequacy Terms:

- *"Loss of load Expectation"* (LOLE): Expected or average number of days during a given time period for which the available generation capacity is insufficient to serve demand
- *"Loss of load Hours"* (LOLH): Expected or average number of hours during a given time period where system demand will exceed the generating capacity
- *"Expected Unserved Energy"* (EUE): Amount of demand (measured in MWh) that the system will not meet during a given time period, averaged across a wide range of system conditions
- *"Conditional Value at Risk"* (CVaR): Expected unserved energy over the X% worst system conditions

The primary objective of the 2023 system adequacy attribute work was to develop a method for measuring emerging risk factors (availability, energy, and fuel assurance) and quantify their impact on system-wide accreditation and requirements. Two study cases were defined: (1) business-as-usual, and (2) enhanced risk assessment. The enhanced risk assessment case was designed to assess the impact of risk factors related to the delivery of energy during more constrained conditions (transfer limited). The enhanced risk assessment also extended the approach followed in the business-as-usual case for capturing weather-dependent outages, by modeling these as a function of the installed capacity. The two study cases were analyzed using three evolving resource portfolios: today, 2027, and 2032.[8]

The impacts of these risk factors were quantified by the resulting changes in accreditation and requirements between the two cases and across portfolios. The outcome of this assessment, which helped inform the solutions hypothesis, offers three key insights.

[7] IEEE reference for a comprehensive description of LOLE resource adequacy terms.

[8] Futures portfolio are based on Scenario 2A in MISO, *MISO Futures Report Series 1A*, November 2023.

INSIGHT: Accreditation aligns with the risk distribution, regardless of the underlying sources of risk modeled, and tracks the contribution of individual resources

The proposed accreditation method (DLOL) aligns availability and need in the planning horizon at the class level. As the generation fleet evolves, the timing, volume, duration, and frequency of loss of load events are expected to change (Figure 5).[9]

The bulk of the risk moves away from the summer gross peak load and distributes across other seasons (Figures 5 and 6). In 2027, the risk is expected to balance between the summer and fall seasons. In 2032, the risk concentrates in the winter, driven by electrification and weather-dependent capacity.

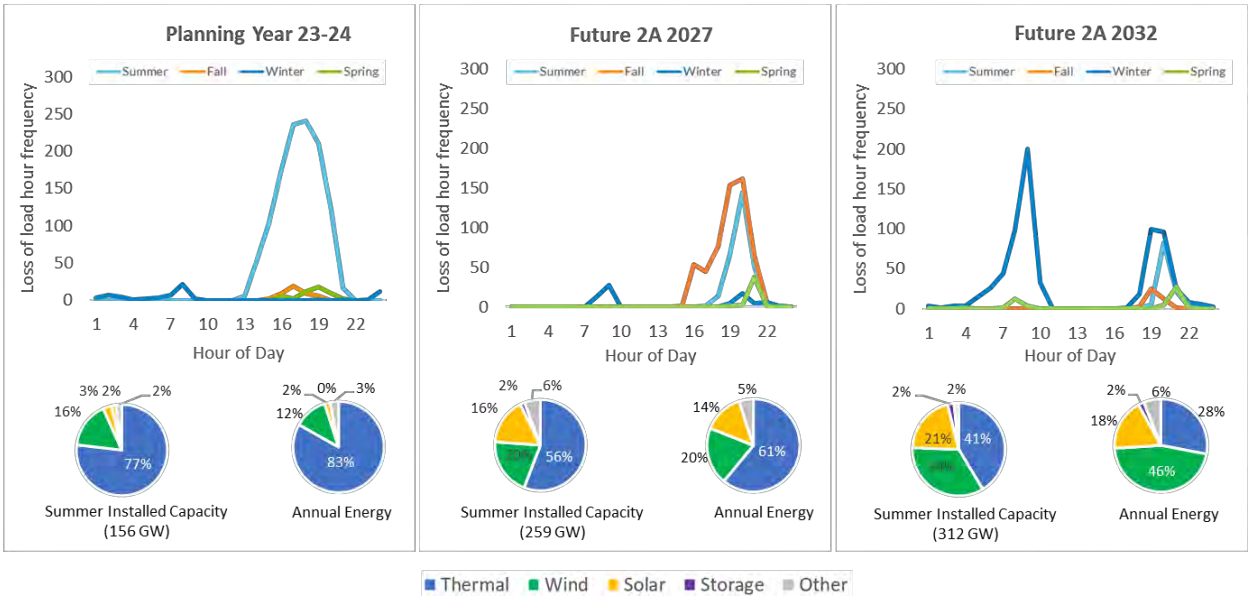


Figure 5: Evolution of risk distribution in future portfolios

These shifts in risk over time impact the accreditation of resources and system requirements, as both rely on the underlying LOLE model. Figure 6 illustrates the changes in summer accreditation and risk distribution from the business-as-usual LOLE simulations. The reduction in wind and solar accreditation in later years is driven by the shift in risk towards twilight hours. The slight increase in storage accreditation is due to the shorter duration and smaller magnitude events in the 2032 portfolio.

[9] A summary of all metrics is included in section A.4.1 of the Technical Appendix.

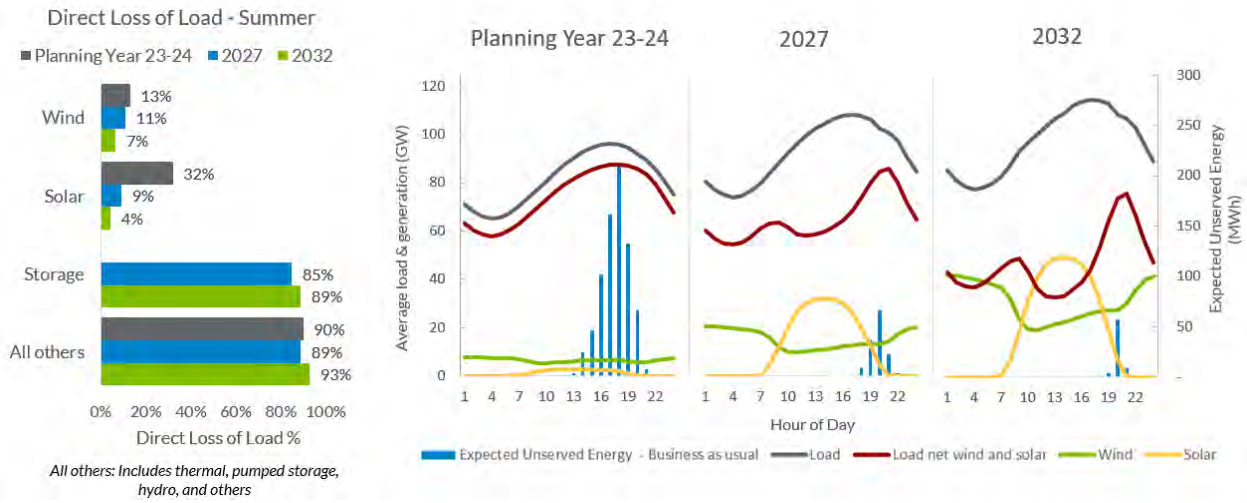


Figure 6: On the left, estimated summer season, class-level DLOL accreditation values for the three portfolios (today, 2027, and 2032) by fuel type. On the right, summer diurnal plots from the LOLE simulations showing average load, net load, and renewable generation for each hour.

Figure 7 shows the forward-looking accreditation results for the winter season. The changes in wind and solar accreditation are small, as the risk distribution in the winter season is concentrated in nighttime hours. The 2032 portfolio shows events that are longer in duration, more severe, and with a higher frequency (multiple events per day). This results in a lower accreditation for energy-limited storage resources[10], as their ability to mitigate risk is proportional to their state of charge at the beginning of the event and total energy available.

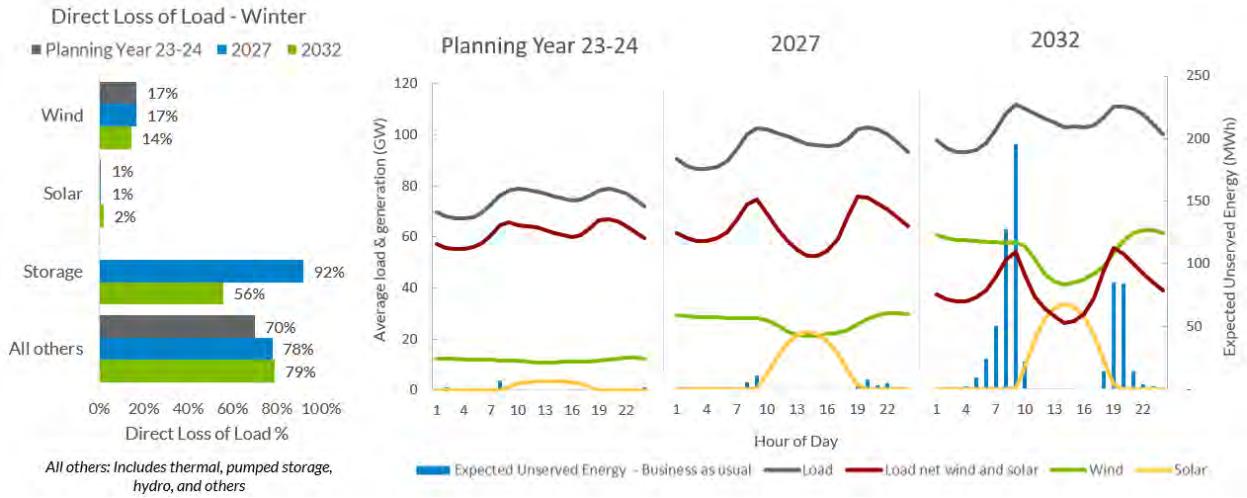


Figure 7: On the left, estimated winter season, class-level DLOL accreditation values for the three portfolios (today, 2027, and 2032) by fuel type. On the right, winter diurnal plots from the LOLE simulations showing average load, net load, and renewable generation for each hour.

[10] Modeled as 4-hour resources in this analysis.

Capturing these interactions and changes in risk patterns are key to the development of a robust accreditation methodology that will serve existing and future portfolios, and the analysis demonstrated that robustness. The full set of forward-looking accreditation results are included in section A.4.1 of the Technical Appendix.

INSIGHT: The acknowledgment of weather-dependent outages and deliverability captures additional risk factors that are projected to appear in future portfolios

The incorporation of weather-dependent outages increased winter LOLE. The incremental winter risk in 2027 and 2032 are primarily driven by weather-dependent correlated outages. Although both portfolios included the same planned retirements, the addition of "flex" units[11] resulted in additional correlated outages in 2027 and 2032. The concentration of long-duration events in extreme weather conditions, such as winter storm Uri in 2021, highlighted wind capacity impacts.

The incorporation of the regional directional transfer (RDT) limits between MISO North/Central and South in the enhanced risk assessment case increased LOLE across all seasons compared to the business-as-usual case (Figure 8). Risk increased the most in spring and winter in 2027 when the RDT constraint was added, while in 2032 risk increased the most in winter. These increases in LOLE show that the inclusion of transmission constraints into the model captures underrepresented transfer limitations between the two MISO regions. The modeling of non-firm external transactions was kept unchanged in the business-as-usual and enhanced risk assessment cases.[12]

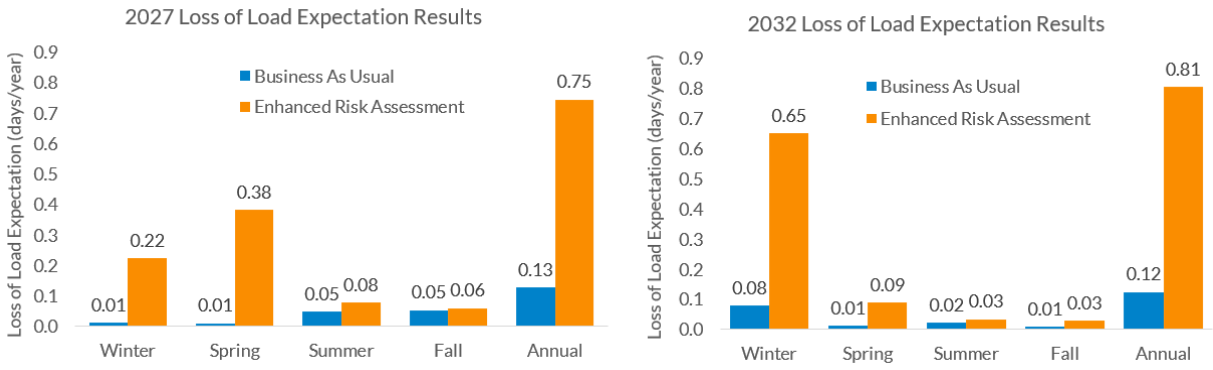


Figure 8: Seasonal LOLE results for the business-as-usual and enhanced risk assessment cases when both at the same adjustment.

The inclusion of the RDT constraint also had an impact on wind and storage accreditation values; the difference in DLOL between the business-as-usual and enhanced risk assessment cases for two resource classes (wind and battery storage) are shown in Figure 9. These accreditation changes can be attributed to transfer limit constraints when the RDT limit is enabled. It also highlights the difference in resource mixes

[11] MISO, *MISO Futures Report, Series 1A*, November 2023.

[12] Modeling of non-firm external transaction was based on historical net-scheduled interchange between MISO and external regions, followed resource adequacy base business practices. More details are available in section A.2 of the Technical Appendix.

between the North/Central and South in the model. Wind DLOL increased in the enhanced risk assessment cases because most of the wind capacity is in the North/Central region. However, most of the loss of load events were concentrated in the South region during periods of high wind availability in the North/Central, driving a higher MISO-wide wind accreditation. Similarly, storage DLOL decreased in the enhanced risk assessment cases because most of its capacity is in the North/Central region and was charging during loss of load events in the South region. Accreditation for the remaining resource classes did not change substantially between cases, with deltas under 3%. These values are shown in section A.4.2 of the Technical Appendix.

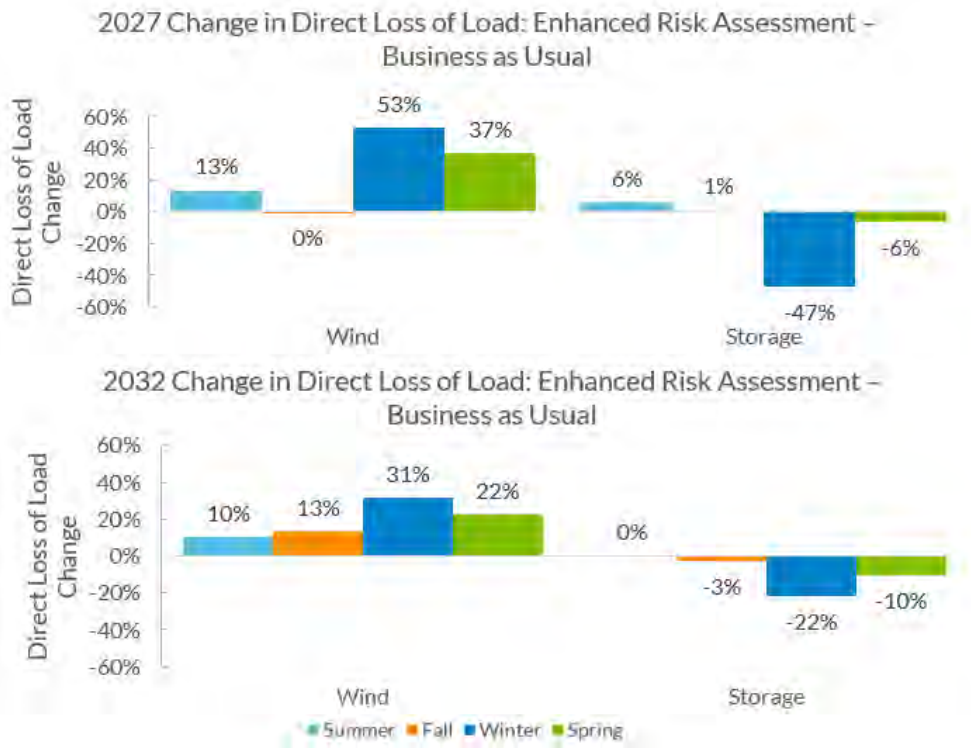


Figure 9: DLOL deltas between the enhanced risk assessment and business-as-usual cases for wind and battery storage resource classes when both cases are adjusted to seasonal LOLE targets.

MISO-wide planning reserve margin requirement (PRMR) increases when the RDT constraint is added to the model for both 2027 and 2032 (Figure 10). This change in the PRMR is due to the difference in fixed load adjustment to meet the 0.1 days/year LOLE target between the enhanced risk assessment and business-as-usual cases. The largest increase in the requirement for both years is in the winter season.

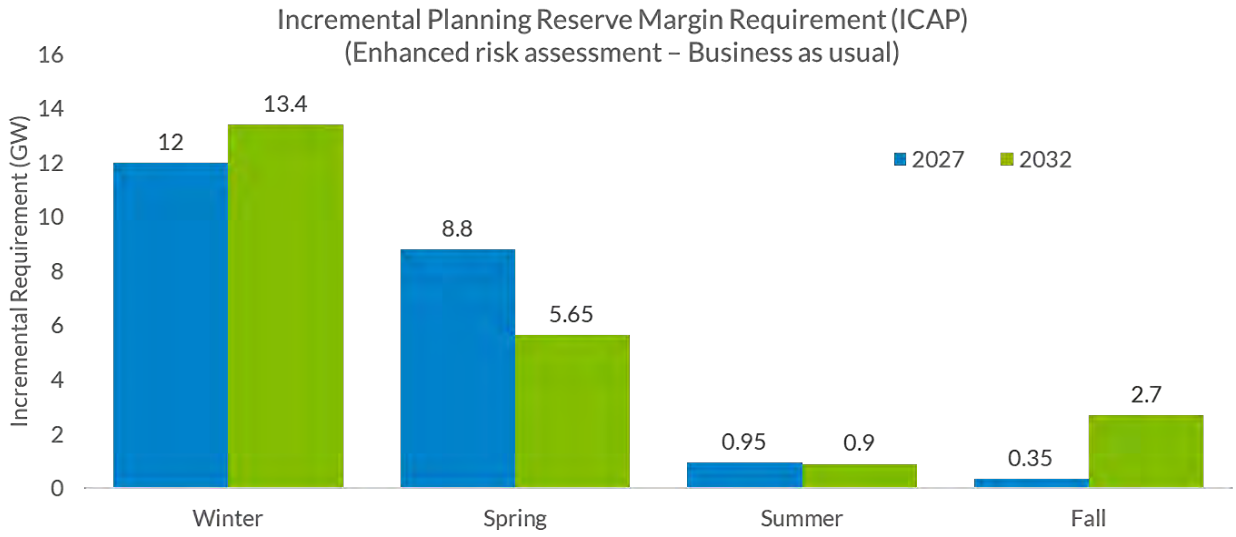


Figure 10: Incremental planning reserve margin requirement (PRMR) by season

INSIGHT: Initial system adequacy-focused flexibility analysis points to potential issues in 2032, additionally analysis is required to understand the implications

Season	PY22-23 Delta EUE (MWh)	2032 Delta EUE (MWh)
Winter	0	1794
Spring	0	6320
Summer	0	304
Fall	0	463

Table 1: EUE difference between business-as-usual and Adequacy-Flexibility analysis

To complete the flexibility analysis within the resource adequacy construct (adequacy-focused flexibility), additional operational data was added to the loss-of-load model, including maximum and minimum unit generation levels, up and down ramp limits, heat rates, and fuel costs. The most challenging week per season (in terms of highest expected unserved energy (EUE), net load, and net load ramping[13]) was selected for the planning year 22-23 and 2032 business-as-usual models.

The differences in expected unserved energy (e.g., delta EUE) between the business-as-usual and Adequacy-Flexibility analysis for the planning year 22-23 model and 2032 models are within the 300-6,320 MWh range (Table 1). For both models, the Flexibility analysis' Loss of Load Hours (LOLH) and LOLE matched exactly to the business-as-usual results of the corresponding model. The total EUE of all seasons matched exactly in the planning year 22-23 model, suggesting that flexibility is sufficient in the current portfolio.

In the 2032 model, MISO observed significant deviation in the results. Spring exhibits especially high EUE under the Flexibility constraints, followed by winter, fall, and summer. Figure 11 shows hours with high

[13] Net load ramping is defined as the difference in net load between time periods t+1 and t.

netload driven by both Flexibility and business-as-usual EUE events in all seasons, while the Flexibility events show high variability in the netload ramping compared to the business-as-usual events. High rates of maintenance of thermal and flexible units in the spring had a major impact on the system's capability to mitigate the increased ramping up and down. This analysis did not include wind and solar generation curtailment, which could reduce ramping needs in the system.

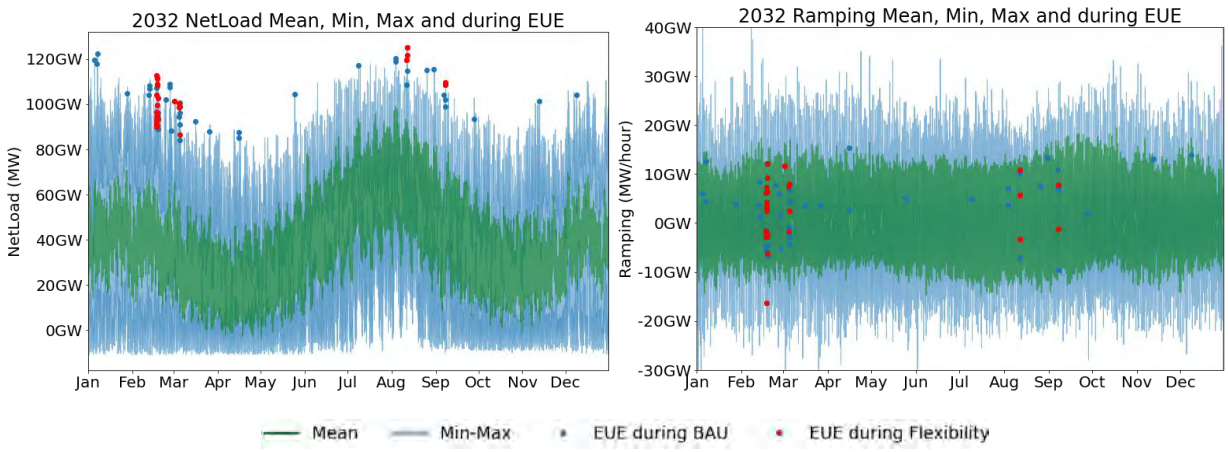


Figure 11: 2032 average, minimum, and maximum netload (left) and netload ramping (right). Blue and red dots signify netload and ramping at the event sample in business-as-usual and Flexibility

While this area of flexibility analysis within the resource adequacy construct presented some interesting results, further work is necessary to evaluate whether its inclusion in the system adequacy modeling is necessary. The proposed solutions in the operational adequacy space (see "Flexibility" section), coupled with the feedback loop between planning and operations, may be sufficient to ensure that flexibility issues are appropriately accounted for.

Find a detailed explanation of the full system adequacy analysis and results in sections A.3.3 and A.4.3 of the Technical Appendix.

SYSTEM ADEQUACY RISK IS BEST ADDRESSED THROUGH CAPACITY REQUIREMENTS, ACCREDITATION AND FORWARD MARKETS

MISO recommends a continued focus on one market clearing product — capacity — because complex interactions between different resource types make it impractical to discretely quantify a specific amount of availability, energy duration, fuel requirement or related adequacy attributes. MISO's analysis finds that the existing combination of capacity and reserve requirements, accreditation, and forward markets provide a sufficient framework to ensure system adequacy. Emerging attribute-related risk factors should be addressed by continually assessing and acknowledging operational risks through constraints in MISO's risk models, the results of which will be reflected in accreditation and reserve requirements.

Additionally, MISO should focus on incentivizing good fuel assurance practices in three ways. (1) MISO will continue to apply and refine the "RA Hours" methodology to reward resources with sufficient fuel to maintain availability during times of risk with higher accreditation values. (2) MISO will create additional incentives through accreditation for resources with higher levels of fuel assurance (dual fuel, etc.) by exploring the creation of a firm fuel class, or similar, with qualification and ongoing operating performance

requirements. (3) MISO will continue the practice of multi-day commitments as needed through the Reliability Assessment and Commitment process and rely on the IMM to recognize extenuating circumstances in the cost of securing fuel.

WHAT NOT TO DO NOW

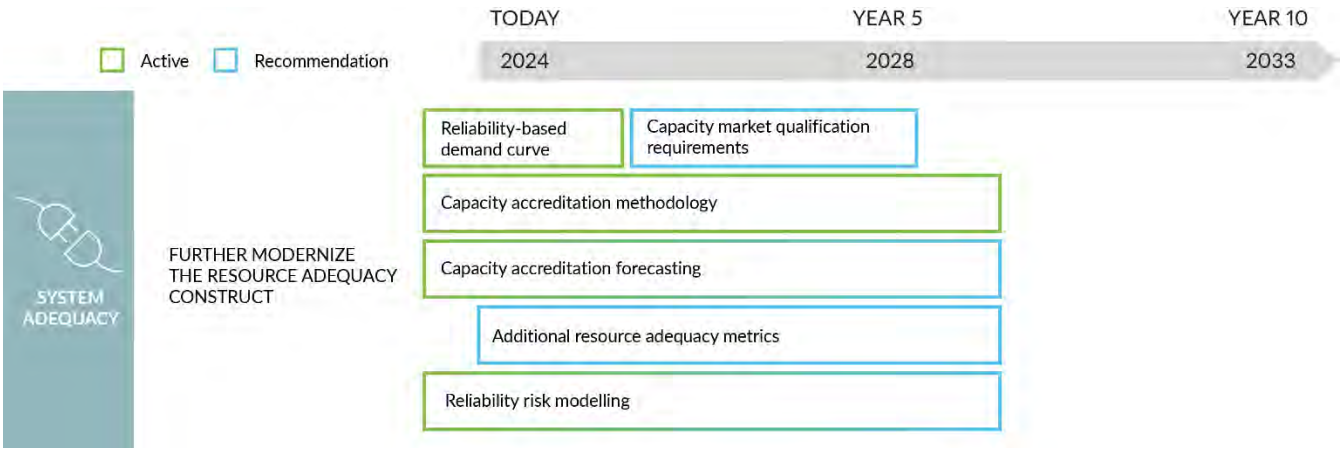
The *Attributes Roadmap* does not recommend new discrete capacity products (e.g., ramp capacity, energy reserves, or winter fuel programs). Capacity products outside the current construct may suppress energy and capacity prices. Additional products will increase complexity, requiring careful operational design, high implementation cost, and long implementation time with highly uncertain benefits.

MISO has also determined that there is currently no need to create an accelerated path for resource interconnection to account for attributes. Adequacy risks are regional in nature and more fully accounted for within the proposed resource adequacy enhancements. MISO continues to be focused on reaching the target queue timelines for all resources, which align with development timelines such that an accelerated path is not expected to result in earlier in-service dates.

There is no current need to account for the system adequacy attribute in the retirement (Attachment Y) programs because, again, adequacy risks are regional and better addressed through resource adequacy enhancements. Unless a policy need arises, Attachment Y is designed to be a stop-gap measure and is an insufficient mechanism to retain resources long-term or send long-term investment signals.

Lastly, MISO does not recommend taking broad action to secure forward gas supplies either through a multi-day market or forward fuel procurement. MISO will continue to commit gas and other resources beyond the day ahead market for limited reliability reasons and will explore improvements to that process and associated tools.

ROADMAP: FURTHER MODERNIZE THE RESOURCE ADEQUACY CONSTRUCT



SYSTEM ADEQUACY: Further Modernize the Resource Adequacy Construct
Implement the **reliability-based demand curve** (RBDC) to signal the value of incremental capacity
Clarify **capacity market qualification requirements** to ensure that resources are available when needed • Clarification of obligations for market participation (e.g., minimum availability criteria, minimum winterization criteria, DIR participation, non-emergency status, etc.) to account for characteristics that cannot be properly modeled
Enhance **capacity accreditation methodology** to value the availability of all resources when needed most • Transition to the proposed methodology to consistently accredit all resources for their availability during periods of highest potential and realized system risk • Create and maintain resource accreditation classes to acknowledge differing risk profiles from similar resource types • Explore an update to the allocation of PRMR requirements to better align with times of risk • Enhance load modifying resource (LMR) accreditation to better align with availability when needed
Forecast seasonal capacity accreditation values annually for future years to understand how future system trends affect resource class accreditation and requirements for the benefit of market participants
Explore and report **additional resource adequacy metrics** to improve the quantification of risk and resource contribution • Include more granular resource adequacy metrics in the annual report, including EUE, LOLH, conditional value at risk (CVaR) • Explore the characteristics of daily LOLE considering EUE and other reliability metrics as the driving metric in the PRM to understand the trade-off between them • *Conditional:* Implement alternative resource adequacy metrics if the exploration reveals a more robust metric than daily LOLE
Improve **reliability risk modeling** to best characterize existing and emerging system risks • Incorporate correlated weather impacts in the LOLE model to account for outages such as those caused by reduced variable energy production or large-scale fuel shortages that are not currently modeled • Incorporate transmission modeling in the LOLE model to account for increasing regional energy transfer requirements that result from the changing fleet and update downstream processes (e.g., accreditation, requirements) to utilize the enhanced geographical resolution • Improve modeling of storage, energy-limited resources, and demand-based resources to properly capture their operational constraints and their additional contributions to the system (e.g., energy balancing, ancillary services) • Explore implications of climate change for both supply and demand to improve load forecasting as well as address uncertainties and high-stress grid conditions • Establish a feedback loop to analyze operational risk to identify diverging trends and continuously realign the risk model

Table 2: Hypothesis solutions roadmap to proactively address system adequacy attribute risk by further modernizing the resource adequacy construct.

SOLUTION: Implement the reliability-based demand curve to signal the value of incremental capacity

MISO's reliability-based demand curve approach[14] seeks to provide more stable price signals for markets participants and regulators to provide the necessary capacity supply, while avoiding excessive infrastructure development. In September 2023, MISO filed tariff changes to FERC that include the following key elements:

- System-wide and sub-regional demand curves
- Incorporation of net cost of new entry and the marginal reliability impact resulting from MISO's loss of load modeling, that together determine the value of capacity
- A reliability-based demand curve opt-out provision for states that choose to not participate in the PRA

Should FERC approve the proposed changes, MISO aims for implementation in the 2025 PRA for Planning Year 2025-2026.

SOLUTION: Clarify capacity market qualification requirements to ensure that resources are available when needed

Characterizing system needs and risks through LOLE modeling is one of the pillars of MISO's resource adequacy construct, but modeling adjustments may not always be sufficient to fully capture systems risks for any number of reasons (e.g., lack of necessary data, software, or computational limitations, etc.). In limited circumstances, MISO recommends establishing new requirements or obligations for capacity market participation, such as minimum availability criteria, minimum winterization criteria, dispatchable intermittent resource (DIR) participation, and non-emergency status. MISO will work with stakeholders to develop these requirements when these attributes cannot be properly ensured through the accreditation construct, LOLE modeling, and capacity market.

SOLUTION: Enhance the capacity accreditation methodology to value the availability of all resources when needed most — and forecast seasonal accreditation values annually for future years to understand how future system trends affect resource class accreditation and requirements for the benefit of market participants

Resource accreditation should reflect the availability of resources when they are most needed. Significant growth of variable, energy-limited resources in the MISO footprint, along with changing weather impacts and operational practices, are shifting risk profiles in highly dynamic ways with implications to resource adequacy and planning. MISO is currently proposing to align capacity accreditation with system risk to estimate the capacity contribution of MISO resources.[15] This approach measures resource accreditation during periods of both highest potential and realized system risks consistently across all resource types. MISO's plan includes a three-year transition for the implementation.

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[14] MISO, *Reliability Based Demand Curves Conceptual Design White Paper*, September 2023.

[15] MISO, *Resource Accreditation White Paper*, November 2023.

As part of the proposed approach, resources are grouped into classes. In the future, MISO should create and maintain resource accreditation classes to acknowledge differing and evolving risk profiles from similar resource types. For instance, there may be a need for increased granularity to acknowledge diverging availability from resources sited in different areas of the MISO footprint or with different levels of fuel assurance. Resource classes should evolve to better track sources of system risks and better represent how to reflect resources characteristics contributions to system adequacy.

Like the proposed capacity accreditation reform, MISO should explore an update to the allocation of PRMR obligations to better align with times of risk. Transitioning the allocation process from seasonal gross peak to risk-based values would create incentives for LSEs to shift load toward those times of the year that are most effective at reducing the potential for unserved energy.

The current capacity accreditation proposal will be applied to all system resources, except for emergency-only resources such as Load Modifying Resources (LMRs). MISO is currently designing improvements to LMR accreditation.[16] The reforms will determine appropriate capacity credits for LMRs that more closely align with their availability and account for specific characteristics (such as notification time), improve LOLE modeling assumptions to align with operations, and align assumptions of resource adequacy processes to facilitate efficient use of LMRs' potential.

Forward-looking accreditation values are an important input in making long-term investment decisions. MISO recommends providing regular forecasted seasonal capacity accreditation values and PRMR estimates to stakeholders, published within existing recurring reports (e.g., Regional Resource Assessment). Ongoing review of these forecasts will allow MISO and market participants to identify and prepare for emerging trends in advance of the capacity market binding period.

SOLUTION: Explore and report additional resource adequacy metrics to improve the quantification of risk and resource contribution

Most MISO resource adequacy processes rely on a single metric - daily LOLE - measuring either expected loss of load in days/year or days/period.[17] As the system risks evolves, so will the nature of risks. Relying on a single metric does not convey the full picture of reliability.[18] Outages with different characteristics such as outage time or magnitude may be considered equally under the 1-outage day in 10-year metric.

While MISO recommends the Planning Resource Margin (PRM) continue to be determined using a single reliability metric, MISO should regularly publish more granular resource adequacy metrics to inform planning decisions and enable members to determine their own needs. These additional metrics may include expected unserved energy (EUE), loss of load hours (LOLH), or conditional value at risk (CVaR). MISO should create a roadmap focused on the need to reform the resource adequacy criterion considering the range of more granular resource adequacy metrics.

[16] MISO, Resource Adequacy Subcommittee (RASC) stakeholder process.

[17] G. Stephen, *et al*, "Clarifying the Interpretation and Use of the LOLE Resource Adequacy Metric", 2022 17th International Conference on Probabilistic Methods Applied to Power Systems (PMAPS), June 2022.

[18] Energy Systems Integration Group, *Redefining Resource Adequacy for Modern Power Systems*, 2021.

After the exploration of additional reliability metrics is complete, MISO should also explore the implications of replacing daily LOLE as the driving metric in the LOLE Study and PRM process. The implications of using other metrics should be understood, including their interdependencies and robustness as the system evolves. Should this exploration reveal one or more metrics that are more robust than daily LOLE, MISO should implement alternative reliability metrics to drive PRMR and accreditation processes.

SOLUTION: Improve reliability risk modeling to best characterize existing and emerging system risks

Current risk modeling performs a Loss of Load Expectation (LOLE) analysis to calculate the Planning Reserve Margin (PRM) requirement to ensure that MISO resources can reliably meet demand. As the fleet transitions, a broader set of conditions must be considered to maintain reliability. MISO recommends several LOLE model improvements to ensure that existing and emerging system risks are more accurately accounted for:

- Incorporate correlated weather impacts to the system. Resource outages caused by reduced variable energy production or large-scale fuel shortages are two examples of risks not currently modeled by MISO.
- Incorporating transmission modeling to recognize that the changing fleet will be enabled by increasing regional energy transfer. The risks related to events limiting transmission should be included in future models.
- Improvements to the representation of emerging technologies[19] and emergency resources to properly capture their operational constraints and additional contributions to the system (such as energy balancing or ancillary services).

As the model improves, results of downstream processes (such as accreditation or requirement setting) will be impacted. Some of these recommendations may have significant implications in those processes. For example, incorporating transmission constraints in the LOLE model will provide additional insight on the locational nature of risk, which could be used to enhance zonal requirements.

Additionally, MISO is currently working to improve its load forecasting system by developing probabilistic forecasting capabilities, including expanding the available load forecasting models and weather scenario data available to the forecasting team. This additional information will allow load forecasts to better capture weather risk associated with climate change. MISO is working to evolve planning assumptions and tools that can address uncertainties and high-stress grid conditions through scenario-based planning that considers a broad range of plausible long-term futures as well as real-world system conditions, including challenging and extreme events.

Finally, MISO recommends establishing a feedback loop to continuously realign the risk model with operational risks. Work is underway to improve operations planning study models for greater consistency with Energy Management System (EMS) models.

[19] Some emerging technologies present new challenges in resource adequacy modeling because their ability to contribute of the system depend on factors beyond whether the units is available or is experiencing an outage. For example, battery storage generation depends on its state of charge and load modifying resource may have limitation on the frequency and duration on their activation.

PLANNING HORIZON ANALYSIS NEXT STEPS

The work of modeling enhancements and understanding their impact on reliability and accreditation will be ongoing. Future investigations into planning horizon attribute risks and solutions could target questions such as:

- How can the LOLE modeling process be enhanced by including additional risk factors in the planned maintenance scheduling?
- What level of transmission granularity is needed to acknowledge local risk factors?
- How should storage operations be captured in LOLE models?

Flexibility

Flexibility is the extent to which a power system can modify electricity production or consumption in response to changing system conditions, expected (*variability*) or unforeseen (*uncertainty*). Flexibility is crucial to operating the energy system where the supply and demand of energy needs to be balanced over different timescales. From an operating timeframe point of view the real-time balance is most crucial. MISO has a primary responsibility towards reliability and ensuring operations and markets can respond to changes in net load ramps over extended timeframes. MISO's energy and ancillary services market should enable adequate system attributes so that Operations is able respond in time and balance the system needs.

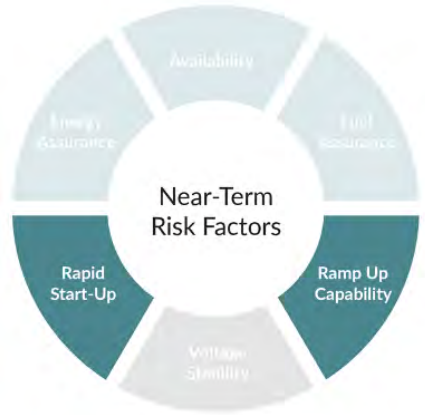


Figure 12: Flexibility near-term risk factor focus areas

MISO's focus for the 2023 flexibility analysis was on the potential shortage of rapid start-up and ramp-up capabilities in future years (Figure 12). Rapid start-up is the ability to quickly start-up offline generation. Ramp-up is the ability to follow load and resource imbalance to track intra- and inter-hour load fluctuations within a scheduled period.

MULTIPLE COINCIDENT SOURCES OF INCREASED VARIABILITY AND UNCERTAINTY DRIVE THE NEED FOR GREATER SYSTEM FLEXIBILITY

Historically, outages, load, and net scheduled interchange (NSI)[20] were the largest contributors of uncertainty and variability in managing the operating margin for the MISO region. MISO has historically depended on imports from neighbors who have had excess capacity. As the resource portfolio across the eastern interconnect evolves to include increasing amounts of variable resources, the complexity of managing operating margins will increase significantly and depending on import availability will become riskier.

Factors contributing to the increasing operational complexity, either due to greater variability or greater uncertainty include (1) increasing frequency and magnitude of system ramps, largely driven by the growth in renewable resources; (2) increased volatility in load forecasts due to changing weather and demand patterns; (3) more volatile generator outages, particularly related to aging of thermal units, extreme weather events, and fuel supply challenges; and (4) greater uncertainty of available energy at low margin hours, particularly in winter/spring evenings, as the fleet becomes more weather-dependent. These sources of increased variability and uncertainty drive the need for greater system flexibility in the future.

[20] Net Scheduled Interchange (NSI) is the net of MWs import and export schedules.

FOUNDATIONAL ANALYSIS

MISO's energy and ancillary services markets will play an important role in incentivizing competition for providing flexibility and other services that support energy delivery and reliability. MISO utilizes a two-settlement system comprising of a day-ahead market and a real-time market in which all products are simultaneously co-optimized. MISO needs to evaluate the ability of its market products to procure sufficient system attributes to maintain reliability without compromising efficiency under the evolving resource mix. This year's attributes analysis developed a simplified model of MISO's markets comprising the day-ahead unit commitment and real-time economic dispatch, which includes MISO's energy and ancillary services market products and rules.

The analysis centered around the simulation of stressed days to measure the potential unserved energy. For the current fleet, MISO chose historical extreme event days from different seasons for simulation. While for the future fleet, MISO selected potential stressed days in the future for comparison. In all simulations, MISO excluded operator reliability and emergency actions in order to provide a more meaningful comparison. Further, intraday commitments were excluded to keep the focus on the market constructs and not on MISO's unit commitment processes. A key limitation of these simulations was the exclusion of transmission constraints other than the RDT, but MISO hopes to address it in future analysis.[21]

The market simulations were carried out using a MISO-enhanced version of the Electrical Grid Research and Engineering Tool (MISO EGRET) that has implemented the main MISO energy and ancillary service market products and commitment rules.[22] This tool was hosted in MISO Research and Development team's Advanced Simulation Environment, which provided the computational environment for running these simulations. This tool has previously been validated through extensive testing against MISO's production market system. For this year's analysis, data for the simulation was taken from day-ahead and look-ahead commitment (LAC) production cases for the two-stage market simulation. A new two-stage simulation framework appropriate for the attributes study was developed as part of this effort. The following key insights have informed the solutions hypothesis:

INSIGHT: Given the fleet transition the increase in net load variability and uncertainty will require new/enhanced market products and dynamic requirements that can achieve the greater flexibility needs on the operational timeframe.

A snapshot of one winter (January) and one summer month (August) across 2022, 2027, and 2032 indicates that the Future 2A fleet results in distinct new patterns for diurnal net load[23] profiles in both seasons (Figure 13).

[21] The key assumptions used in this analysis are described in section A3.2 of the Technical Appendix.

[22] MISO-EGRET tool is described in the MISO, *Technical Appendix: RRA Assumptions and Methodology*, from MISO, *2022 Regional Resource Assessment*, November 2022.

[23] Net load is defined as gross load net of wind and solar generation.

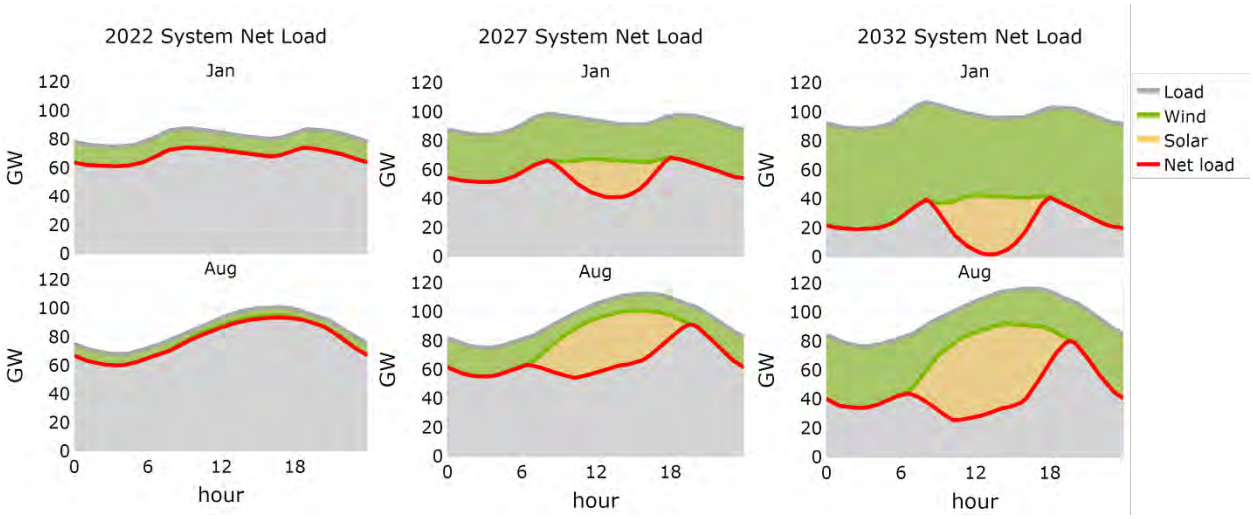


Figure 13: Monthly averages of diurnal net load components for January and August

With the generation fleet changes, the MISO winter diurnal net load pattern will begin to morph into the familiar "duck curve" shape,[24] with net load dropping around mid-day due to the increased presence of solar generation. In the evening as solar production decreases and electricity consumption increases, there is a significant increase in net load ramp-up. By 2032, the growth in wind and solar production in January results in even lower average net load around midday. In the summer months, the MISO system has historically seen a single daily net load peak in the late afternoon hours. By 2032, due to solar production, the daily net load peak is shifted to later in the day, into the post-sunset hours. Further the net load ramp needs in the evenings are projected to be high.

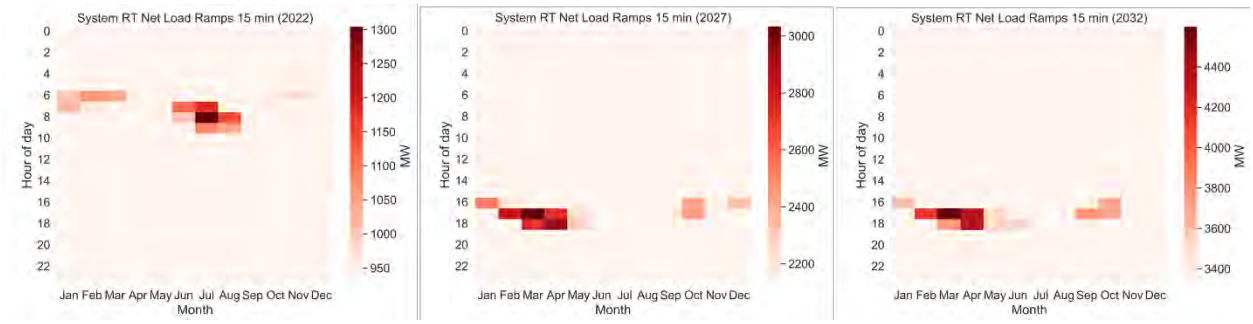


Figure 14: Highest 10 percentile of short duration net load up-ramps

Another way to visualize the ramping patterns is to look at the highest 10 percentile of short duration up ramps (Figure 14). The quantitative change is significant. The maximum 15-minute up-ramp needs will be more than double by 2027 and 3.5 times by 2032 compared to 2022 levels.

[24] NREL, *Overgeneration from Solar Energy in California: A Field Guide to the Duck Chart*, November 2015.

INSIGHT: The projected increase in risky days and lack of guarantees for availability of emergency and external resources increase the need to rely on demand side resources

The results from the Attributes market simulations of the historical events differ from the actual observations due to the assumptions described above. In reality, MISO Operations, acting in coordination with its neighbors, took many actions to manage the events successfully. The historical extreme event simulations show MISO's reliance on emergency resources as well as external resources, both of which are not guaranteed to be available in the energy market. For the historical summer event (Figure 15) in the base case the day-ahead commitment was inadequate to meet the real-time load due to a forecast error resulting in unserved energy. Additional scenarios were performed with different combinations of challenging conditions, such as the absence of LMRs or limited imports from neighbors (below the original maximum of approximately 13 GW systemwide net import amount). These cases increase unserved energy, with the worst result happening for the case with no imports into MISO and no LMR deployments (i.e., a "No LMR, No NSI" scenario). These scenarios highlight the importance of operator actions in maintaining reliability.

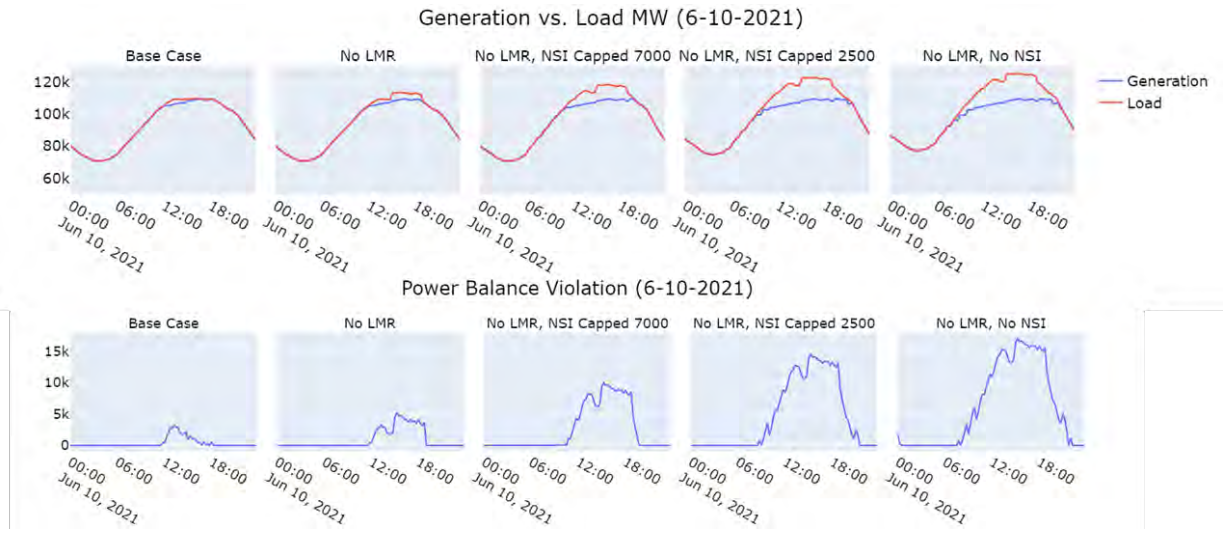


Figure 15: Simulation results for the summer event under different LMR and NSI scenarios

Over the past several years MISO has experienced several stressed days where it used emergency procedures as well as been dependent on imports from its Eastern Interconnect neighbors to manage challenging system conditions. Based on the results of this analysis these high-risk days are projected to grow in number and get more spread out across the year as the potential stressed days begin to show up in the shoulder seasons (Figure 16).

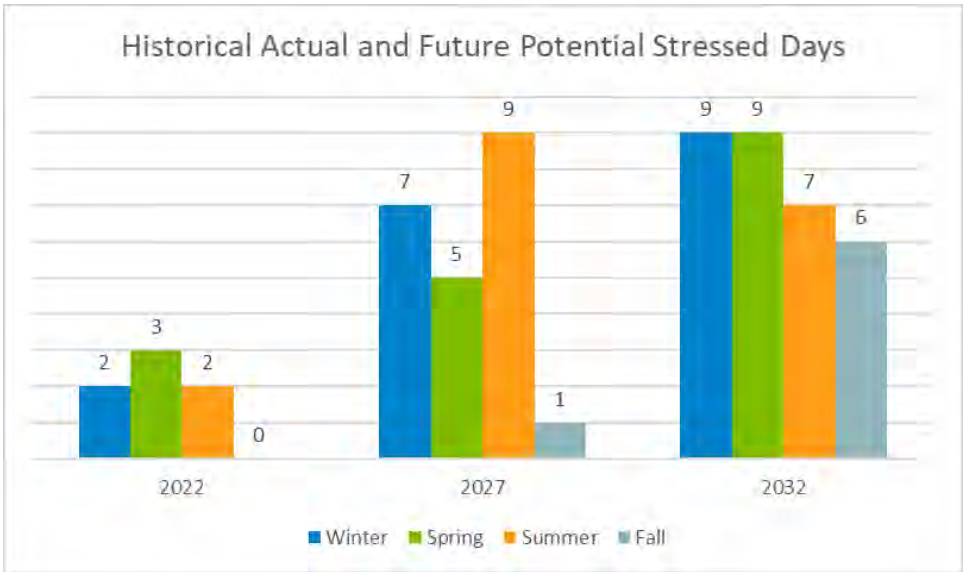


Figure 16: Historical events and future potential stressed days by season

With extreme weather, a greater number of high-risk days and the potential for climate change impacts, there are concerns for system reliability.

INSIGHT: The projected increase in duration and severity of events coupled with the retirement of conventional resources highlights the need for enabling the potential of emerging resources

The duration and severity of unserved energy events in a system with large penetration of renewables could increase since a large, sustained drop in renewable output could become the largest concern to manage in the operating timeframe. Figure 17 shows simulation results from various scenarios for a potential stressed day in Winter 2027. Figure 17a shows a small amount of unserved energy for the Base Case, because the Day-ahead commitment is inadequate to meet the Real-time load. Three individual stress scenarios are considered: a 50% drop in wind production throughout the day, a removal of external imports (MISO rather ends up exporting power), and a high-impact single gas pipeline outage. This last contingency, given Future 2A projected retirements, occurs in the MISO North/Central region and amounts to 6 GW. The wind-reduction scenario has the largest increase in unserved energy amongst the three cases. Finally, the worst-case event was simulated, where all 3 stress conditions occur on the same day.

Figure 17b illustrates how the use of quick-start units can address flexibility challenges. The worst-case event is used as the starting point and then quick start units are added until the unserved energy is mitigated. Quick start units are added beginning with the fastest group based on their lead-time of up to 20 min (i.e., 'quick 20 min'), and in later instances more units are added with increasing lead times of up to 60 min, 120 min etc. The mitigation occurs with units of lead-time of up to five hours.

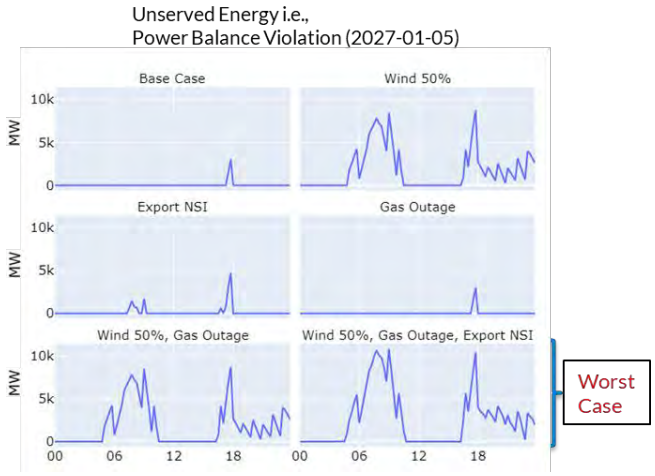


Figure 17a: Simulation results for base case and stressed scenarios for the winter 2027 event

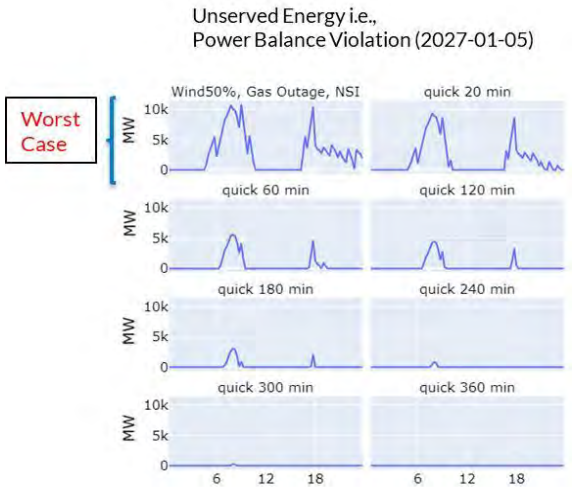


Figure 17b: Simulation results for worst stress case and mitigation using quick start units for the winter 2027 event

The Future 2A fleet assumes a new generator type known as the "flex" unit, which for this analysis is assumed to have the characteristics of fast combustion turbines. Thus, the overall quick start capacity in the 2027 and 2032 generation fleets is larger than in the current fleet.

Find a detailed explanation of the full flexibility analysis and results in section B of the Technical Appendix.

FLEXIBILITY ATTRIBUTE RISK IS BEST ADDRESSED THROUGH MARKETS IN THE OPERATING TIMEFRAME

MISO recommends focusing the mitigation of flexibility risk on the operating horizon, specifically the real-time and day-ahead energy and ancillary services markets where key market design elements exist and are tested.

A focus on expanding current and new market products is needed to optimize flexible attributes and ensure availability and deliverability in real time on three fronts. MISO should (1) refine the quantities and formulation of ramping products (e.g., ramp, short-term reserves) based on operational experience and forward-looking studies, (2) explore implementing dynamic reserve requirements based on system risk, and more granular locational definitions to enhance deliverability of reserves, and (3) explore a new product for uncertainty management to reduce the need for "out-of-market" unit commitments for managing the day-ahead to real-time uncertainty.

Additionally, MISO should identify and address potential barriers preventing all resources from providing market services, allowing more resources to provide needed flexibility to the system. It should also create the capability to include flexible loads (e.g., controllable or price sensitive load) to provide market services.

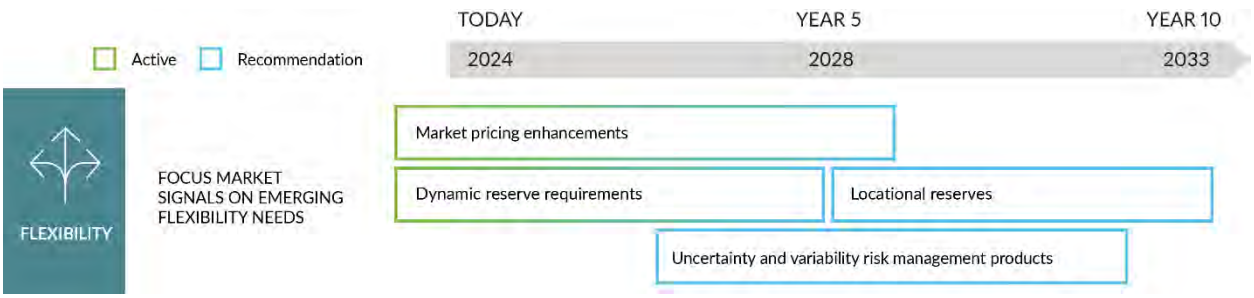
WHAT NOT TO DO NOW

MISO projects, based on internal modeling efforts, that there will be sufficient resources to meet flexibility needs and therefore the development of discrete, flexibility requirements or derates in the capacity market is unnecessary at this time. Interactions between flexibility and capacity add excessive complexity to resource adequacy and may suppress capacity prices. Also, new capacity products do not directly increase utilization of that new flexibility characteristic in the operating horizon.

Additionally, the Forward Reliability Assessment Commitment remains MISO's preferred method to inform market participants of upcoming needs. Efficacy is expected under future conditions making a multi-day market product unnecessary. Market participants are responsible for continuing to signal their needs to MISO.

Lastly, MISO does not currently recommend consideration of flexibility attributes within MISO's resource interconnection or exit programs (Attachment Y) as flexibility risks are regional and will be fully accounted for within the expanded and new ancillary services products proposed in the roadmap below.

ROADMAP: FOCUS MARKET SIGNALS ON EMERGING FLEXIBILITY NEEDS



FLEXIBILITY: Focus market signals on emerging flexibility needs
Implement **market pricing enhancements** to send price signals that reflect the value of resource availability • Update the value of lost load, which sets the price cap in the energy market, to send better price signals during emergency and scarcity conditions • Change the operating reserve demand curve to improve the price incentive for flexibility • Update the transmission constraint demand curves for improving congestion management
Implement **dynamic reserve requirements** to have better alignment between system conditions and risk • Establish daily reserve requirements • Dynamic requirements for reserves (regulation, contingency) • Dynamic requirements for ramp capability product
Implement **locational reserves** to improve deliverability of reserves • Evaluate dynamic reserve zones to better align zonal definitions and system conditions • *Conditional:* Explore nodal reserves as an option to address the issue of reserve deliverability

Develop **new products for uncertainty and variability risk management** on the multi-hour time horizon to maximize the flexibility capabilities of existing resources

- Revisit participation model for flexible resources (potentially separate qualification for up and down ramp; additionally propose up and down regulation)
- Explore a new product for uncertainty management to manage flexibility needs and reduce out-of-market manual commitments
- Explore additional products to manage intra-hour netload variability (e.g., 30-, 60-min)

Table 3: Hypothesis solutions roadmap to proactively address flexibility attribute risk by focusing market signals on emerging flexibility needs.

SOLUTION: Implement market pricing enhancements to send price signals that reflect the value of resource availability

MISO's Resource Availability and Need (RAN) program identified concerns that market prices during historical emergencies and shortages have not reflected the scarce conditions. MISO's IMM has made multiple recommendations to improve MISO's emergency and scarcity pricing mechanisms. Efficient and transparent prices encourage Market Participants to make efficient operational decisions that can support and inform investment decisions. MISO is evaluating scarcity pricing during shortage events and near-term, mid-term, and long-term enhancements to various scarcity pricing mechanisms. In MISO's markets the locational marginal prices (LMP) are capped at the value of lost load, which is currently $3,500/MWh. This value should be updated to ensure that valid prices are not truncated during reserve/transmission violations. MISO should evaluate updates to the operating reserve demand curve, to ensure that price signals are consistent with price formation principles. Along with updates to the value of lost load and operating reserve demand curve, the transmission constraint demand curve should be updated to ensure that MISO is able to manage congestion properly through price incentives during operating reserve shortages. The enhancements should send better price signals and manage growing uncertainty, incent flexibility, improve transparency, and address issues identified during recent emergency events. MISO is exploring additional enhancements to further improve price formation during emergency and scarcity conditions on a longer time horizon.

SOLUTION: Implement dynamic requirements to have better alignment between system conditions and risk

MISO co-optimizes energy and reserves leading to significant benefits for the footprint, including reduced costs and improved flexibility. Reserves are procured to provide backup capacity if necessary to deal with uncertainties and contingencies in the system that may impact reliability. With a transitioning resource portfolio, MISO is facing increasing variability and uncertainty in the availability of resources and system demand. MISO currently uses static reserve requirements. However, with higher levels of intermittent renewable resources MISO recognizes the need to move to dynamic reserve requirements so that reliability needs are better aligned with efficient market outcomes. As a first step, MISO looks to establish daily reserve requirements based on the forecasted risk level for the upcoming operating day. Future exploration should include intra-day dynamic reserve requirements derived from probabilistic net risk prediction as well as dynamic ramp product requirements to better manage ramp and uncertainties. In the future, with more wind and solar in the system, large drops in renewable production within 10 minutes could surpass the

single largest unit standard currently in use. This should require updating the contingency reserve requirements.

SOLUTION: Implement locational reserves to improve deliverability of reserves

Another key challenge associated with the increased uncertainty and variability is that of reserve deliverability, where the reserves may not be deliverable in real-time due to congestion. Historically to reliably deliver reserves, MISO utilized reserve zones in order to procure reserves in a dispersed manner. These reserve zones can be updated on a quarterly basis in conjunction with the network model updates. Currently MISO is using the reserve procurement approach on select constraints. MISO needs to implement improved locational granularity in its reserve products in order to ensure reserve deliverability. MISO should evaluate the possibility of dynamic reserve zones as a first step towards addressing this concern. Updating the reserve zones on a more frequent basis should improve market efficiency and system reliability, since there would be better alignment between zonal definitions and system conditions.

Conditionally, if additional reserve deliverability enhancements are required after the implementation of dynamic requirements, MISO should explore the procurement of reserves on a nodal basis in order to account for intra-zonal transmission congestion. The nodal reserve model could reduce the need for expensive out-of-market reserve disqualifications currently being utilized to manage the challenge of reserve deliverability.

SOLUTION: Develop new products for uncertainty and variability risk management on the multi-hour time horizon to maximize the flexibility capabilities of existing resources

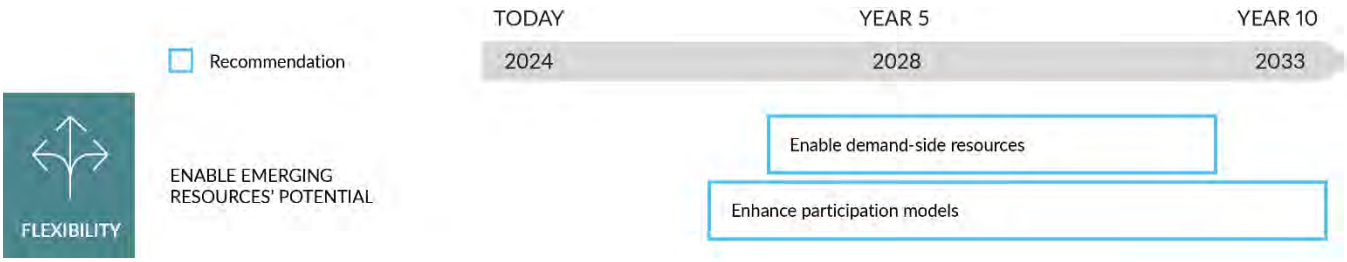
Currently in MISO's market resources must be able to provide both upward and downward ramp to participate in the ramp capability product. This places limitations on some types of resources from participating in the ancillary services market. MISO should separate the qualification requirements for upward and downward ramp capability, which would allow more flexibility for different resource types to participate in the market. Further MISO should separate regulation into a regulation up product and a regulation down product to allow resources that are currently prevented from providing regulation due to congestion to provide regulation down. These solutions can expand the pool of resources which provide ancillary services.

When there is a high degree of uncertainty operators may commit units "out of market" as insurance for the possibility of unexpected high net load. This uncertainty is expected to increase as the MISO fleet transitions to higher penetration of renewables. MISO should evaluate the development of a new uncertainty management product for managing these uncertainties. An uncertainty management product would allow "in market" procurement of units to meet uncertainty that would be committed when needed or released when not. This product could be provided by online and offline resources that are available to respond within certain response time (e.g., four hours lead-time). There may be a need for reserving long-lead units many hours in advance otherwise MISO might not have enough quick start resources to respond in time and avoid an unserved energy event. MISO should investigate how this product would work in conjunction with the current short-term reserve product.

Maintaining real-time power balance requires ramp flexibility from online units which has become more challenging as the proportion of intermittent renewable generation has increased. In 2016, MISO implemented a 10-minute ramp capability product to manage both variations (expected changes) and

uncertainties (unexpected changes) in the net load. The ramp capability product was designed to mitigate ramp shortages which were a common cause of price spikes. The current ramp capability product might not be able to manage extreme cases of ramping needs such as larger intra-hour ramps which are projected to occur as the penetration of renewables increases.[25] Hence MISO should consider additional products for longer ramp durations to manage the increasing intra-hour variability.

ROADMAP: ENABLE EMERGING RESOURCES' POTENTIAL



FLEXIBILITY: Enable emerging resources' potential
Enable demand-side resources to enhance responsive load participation in energy markets • Enable responsive load participation in energy markets • Enable visibility and controllability of Distributed Energy Resources (DER) in market operations
Evaluate options for **enhancing participation models** to allow all resources to provide market services to maximize capabilities • Model multiple configuration resources in day-ahead market to increase flexibility and reduce commitment costs • Further optimize energy storage and co-located resources to leverage flexibility • Ensure commitment flexibility and management of days when net load approaches low values

Table 4: Hypothesis solutions roadmap to proactively address flexibility attribute risk by enabling emerging resources' potential.

SOLUTION: Enable demand-side resources to enhance responsive load participation in energy markets

Within MISO's footprint, demand resources that are used towards meeting the Planning Reserve Margin Requirement (PRMR) as part of the Planning Resource Auction (PRA) are known as Load Modifying Resources (LMR). LMRs include behind-the-meter generation and demand resources. In addition, MISO has a demand resource type known as Demand Response Resources that can provide service to the energy and ancillary services market. As of 2022, the majority of the approximately 12 GW of demand resources in MISO are classified as LMRs and only a small amount is classified as DRRs.

[25] MISO, *MISO's Renewable Integration Impacts Assessment (RIIA) study*. Summary Report. February 2021.

One of the primary drivers of tightening operating margins is the accelerated retirement of thermal resources, which has increased the frequency of emergency declarations, with MISO relying more often on LMRs during these emergency events. In the past several years MISO has made changes to improve the availability and flexibility of LMRs for reliability such as reducing the maximum notification time requirement for LMR capacity accreditation from 12 hours to six hours. Maximum notification requirements should be further reduced to ensure maximum flexibility during emergency events.

MISO should increase its understanding of LMR capabilities and visibility into their granular locations to support more efficient and reliable commitment and dispatch. Part of the strategy may include leveraging emerging LMRs in the energy and ancillary services market. Moreover, there is a need for a detailed analysis of demand response participation across all MISO markets, which will inform a comprehensive strategy for better enabling load participation in MISO markets. Flexible price-responsive demand can provide many benefits, including mitigation of large net-load ramps, better management of contingency events, and enhanced market efficiency.

As the generation fleet transitions and new technologies enter the market MISO will need to evolve its operational and planning processes. Significant changes are expected in the coming decade on the demand side and supply side. One such coming transition focuses on distributed energy resources (DER). FERC Order 2222 requires DERs be allowed to participate in all aspects of Regional Transmission Organization (RTO) markets. This poses a number of challenges for MISO's operations, especially relating to visibility and controllability. MISO needs to consider the impacts of DERs on load forecasting. Further, MISO needs to implement distributed energy aggregated resources into the market engine, asset registration and settlements. Additionally, there is a need to identify and mitigate obstacles to customer readiness for DERs.

In total, MISO should find ways to increase participation of load resources in the MISO market and increase the flexibility they would contribute through MISO's various market products.

SOLUTION: Evaluate options for enhancing participation models to allow all resources to provide market services to maximize capabilities

With the advent of emerging resources, MISO should explore enhancing participation models to maximize the utilization of capabilities from these resources, along with those already present in the system. The harmonization of existing and upcoming capabilities throughout the energy transition will ensure smooth operations. The following are some examples that would contribute to this solution.

The multi-configuration resource model can enable significant flexibility from combined-cycle gas turbines (CCGT) across the MISO footprint. CCGTs with their ability for fast-ramping and quick response times could be a critical resource to addressing the variability needs. As the penetration of renewables increases the multi-configuration resource initiative can more fully exploit the capabilities of such resources to support the increasing flexibility needs of the system.

Large deployment of storage resources will present additional challenges in operations because, unlike traditional assets, their capabilities at any moment in time depends on their past actions. Charging and discharging decisions influence their state of charge at any moment, which influences the amount of energy they can generate or their ability to contribute to ancillary services. MISO should work to identify and mitigate any participation barriers for energy storage resources and co-located resources in MISO's markets that could help enable the additional optimization of such resources.

Finally, as the variable renewable penetration increases, the net load that needs to be covered by the remaining resources changes. Particularly, the minimum values of net load become lower, requiring a surge in the number of cycles for other resources between full generation and minimum generation levels. MISO should investigate minimum generation logic to ensure adequate commitment flexibility.

OPERATING HORIZON ANALYSIS NEXT STEPS

In addition to enhancements to its market products and requirements MISO should continue to focus on improvements to forecasting, visibility and commitment processes to ensure that MISO's operations are able to effectively manage challenging system conditions. One enhancement should include refinements to unit commitment tools so operators will increase their uptake of the Look Ahead Commitment (LAC) engine's recommendations.

Future investigations into operating horizon attribute risks and solutions could target questions such as:

- How should MISO design the new uncertainty management product given its sequencing with the short-term reserve?
- Should MISO implement a new intra-hour ramp product? This would be in addition to the existing 10-minute ramp capability product.
- How should MISO modify participation models which enable load modifying resources (LMR) in energy markets?
- How should MISO modify emergency pricing to avoid price suppression during events?

System Stability

System stability is the attribute of a power system that enables it to remain in a state of operating equilibrium under normal operating conditions and to regain an acceptable state of equilibrium after being subjected to a disturbance. MISO's focus for this year's analysis was on the voltage stability family of issues (Figure 18). Figure 19 shows a power system stability taxonomy often used in technical papers and how voltage stability relates to other system stability components.[26]



Figure 18: System stability near-term risk factor focus area

Voltage stability refers to the ability of a power system to maintain steady voltages close to nominal value at all buses in the system after being subjected to a disturbance (e.g., loss of a transmission line) and is dependent on the ability of the combined generation and transmission system to provide the power required by the loads.[27] [28] Voltage stability is often thought of as load-driven rather than resource-driven, though resource characteristics effect voltage stability outcomes.

Find the detailed definition and explanation of MISO's current state voltage stability considerations, including transfer scenarios in reliability planning and contingencies in real time operations, in section C of the Technical Appendix.

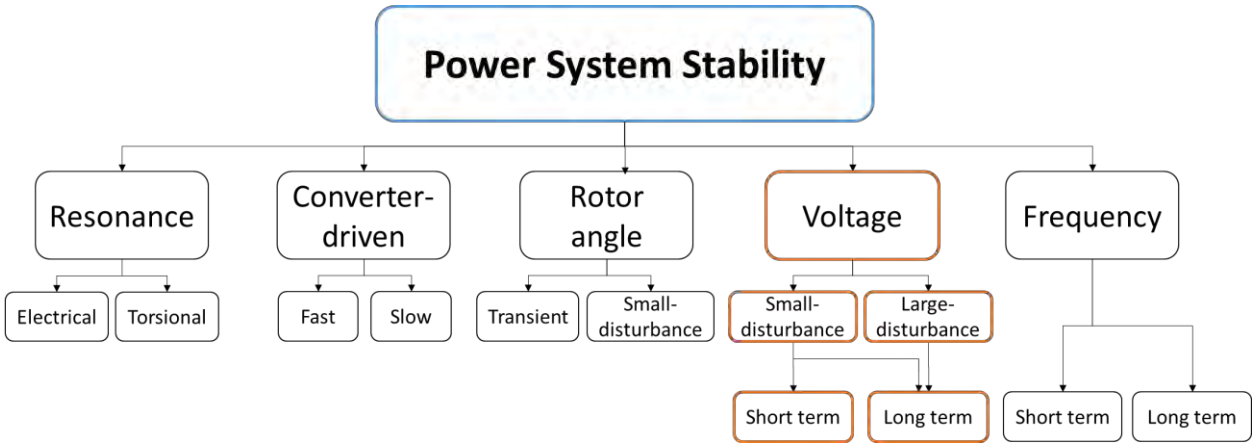


Figure 19: Taxonomy of power system stability considerations

[26] N. Hatziargyriou *et al*., "Definition and Classification of Power System Stability – Revisited & Extended," in *IEEE Transactions on Power Systems*, vol. 36, no. 4, pp. 3271-3281, July 2021.

[27] P. Kundur *et al*., "Definition and classification of power system stability," IEEE Trans. Power Syst., vol. 19, no. 3, pp. 1387–1401, May 2004.

[28] T. Van Cutsem and C. Vournas, *Voltage Stability of Electric Power Systems*. Norwell, MA: Kluwer, 1998.

VOLTAGE STABILITY-RELATED CHALLENGES ARE EXPECTED WITHIN FIVE YEARS

Several factors cause voltage instability, such as insufficient reactive power support, excessive loading, loss of transmission lines or generators, or inadequate voltage regulation. Emerging instability challenges are strongly correlated with today's energy transition trends, potentially leading to weak grid conditions under which instability issues materialize with greater frequency. Trends affecting voltage stability include:

- Synchronous machine retirements (e.g., coal-fired generators) reducing system strength and availability of reactive power
- Grid-following inverter-based resource (IBR) additions (e.g., solar generators) with software defined controls driving operating characteristics that are different from synchronous machines
- Generation siting that is further from load
- Changing dispatch patterns affecting synchronous machine fleet availability
- IBR model quality (verification and validation)

MISO's Renewable Integration Impact Assessment (RIIA) study indicated that voltage stability and inverter-based converter stability are among the first stability-related challenges the MISO system will likely face.[29] These challenges are projected to arise when renewable resources serve between 30% to 40% of MISO system annual energy. According to MISO's Future 2A resource expansion modeling, the 30% energy threshold may be reached around the year 2027.[30] Among the stability-related challenges studied in RIIA, not only are voltage stability challenges expected to emerge early in the energy transition, but the anticipated mitigation capital cost is expected to be the highest.

A lack of adequate voltage stability could result in loss of load in an area or protective system tripping of transmission lines or system components, potentially leading to cascading outages. Voltage collapse, one potential result from voltage instability, has been identified as a contributing factor in large scale blackouts across the globe, including Scandinavia (2003), the northeastern U.S. (2003), Athens, Greece (2004), and Brazil (2009). During the northeastern U.S. event in 2003, voltage instability resulted after multiple line tripping contingencies caused voltage fluctuations and reactive power deficiencies, causing generators and transformers to trip or malfunction.

ADVANCING VOLTAGE STABILITY ANALYSIS INCLUDED A NEW FOCUS ON EMERGING TOOLS AND GRID-FORMING INVERTER EFFICACY

This year's voltage stability analysis focused on (1) characterizing system strength using the short circuit ratio (SCR) approach, and (2) characterizing resources and stability limits using the dynamic impedance approach. The analysis characterized locations and potential severity of weak grid issues which often indicate potential stability challenges. Screening approaches, including those contemplated in this analysis, are used to identify areas and conditions that require deeper analysis. The two approaches are intended to bring visibility to a changing system and offer tools to account for resources' unique stability contributions in subsequent analysis.

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[29] MISO, *MISO's Renewable Integration Impacts Assessment (RIIA) study*. Summary Report. February 2021.

[30] MISO, "Future 2A Expansion and Preliminary Siting". Presented at LRTP Workshop, March 10, 2023.

The SCR approach is known to have limitations in areas of high inverter-based resource penetration as the metric is most appropriate when considering an IBR plant connected to a strong grid without the control interactions from other nearby inverters. While variations of the SCR metric account for interactions, modern inverter control topologies are beginning to decouple the IBR's fault contribution from system strength contributions, concepts that are tightly coupled in grids where synchronous machines are dominant.

Grid-forming versus grid-following nomenclature:

- *"Grid-following"* (GFL) controls require a voltage source to maintain operation
- *"Grid-forming"* (GFM) controls create a voltage source and can operate in standalone mode

While these oversimplified terms are useful to communicate inverter capabilities broadly, control capability classification is more of a spectrum. For example, very fast grid-following controls provide some of the same support capabilities as grid-forming but are not capable of standalone operations.

The dynamic impedance method is relatively new, and MISO is working with industry partners to advance the understanding of its use and limitations. Using the approach to characterize grid-following IBR presented challenges, especially for large disturbances which resulted in severe voltage depressions. Using the approach for grid-forming IBR yielded promising results where both the large signal and small signal screening outcomes appear to be accurate. MISO is still investigating the method's efficacy for different applications based on other industry research evaluating similar approaches. [31, 32, 33]

INSIGHT: Localized pockets of stability challenges may materialize if emerging risks are not made visible and mitigated through controls and asset deployments

MISO's system strength screening analysis and results showed the highly localized and dynamic nature of potential voltage stability challenges, highlighting the need for improved visibility and proactive mitigation. System strength was shown to be affected by both long-term factors, such as a changing resource mix and transmission build, and short-term factors, like resource dispatch patterns across seasons. Using short circuit ratio (SCR) as an indicator of system strength, MISO completed a comparison analysis between future year and seasonal scenarios.

To consider the longer-term drivers, MISO compared the short circuit ratio (SCR) metric between a modeled 2025 summer peak and a modeled 2033 summer peak. Figure 20 shows the decrease (in red) or increase (in green) of the SCR metric, an indicator of system strength, between the two models and highlights the localized nature of system strength change.

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[31] Gu Y., Green T., "Power System Stability with a High Penetration of Inverter-Based Resource," in *Proceedings of the IEEE*, vol. 111, no. 7, pp. 832-853, July 2023, page 14, first paragraph.

[32] J. Sun, "Impedance-Based Stability Criterion for Grid-Connected Inverters," in *IEEE Transactions on Power Electronics*, vol. 26, no. 11, pp. 3075-3078, Nov. 2011, page 1, last paragraph.

[33] S. Shah, *et al.*, "Impedance Methods for Analyzing the Stability Impacts of Inverter-Based Resources," in *IEEE Electrification Magazine*, vol. 9, no. 1, pp. 53-65, March 2021, Section on "Large-Signal Impedance Analysis".

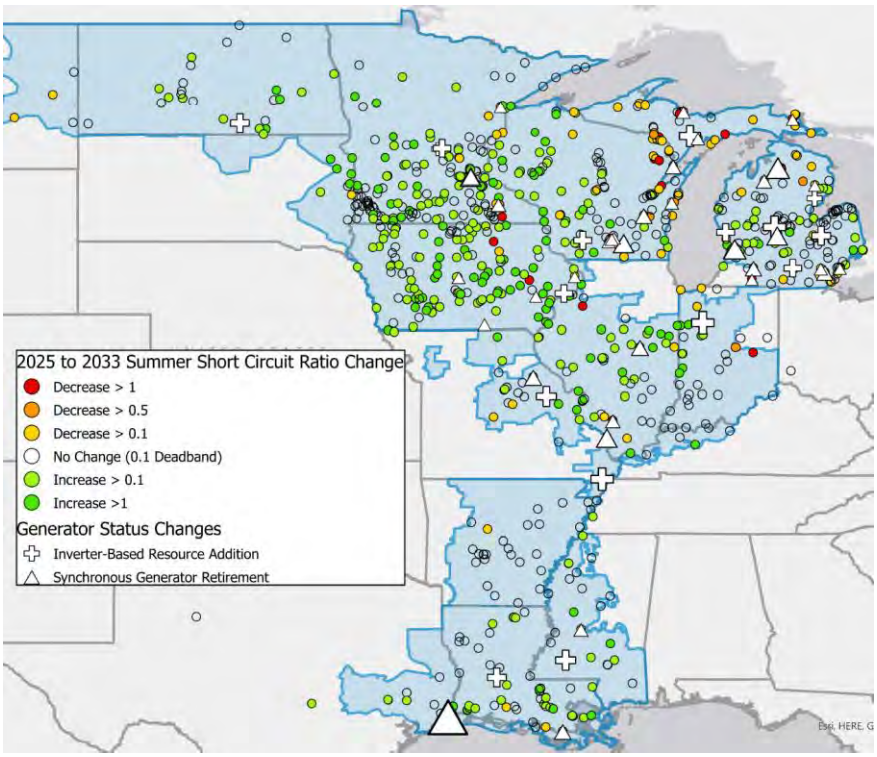


Figure 20: Change in short circuit ratio (SCR) between MTEP23 2025 summer peak and MTEP23 2033 summer peak cases[34]

While this view shows the change in SCR as the resource portfolio evolves, the actual magnitude of SCR is crucial for using the metric as a screening tool. Additional details are contained in section C.3.2 of the Technical Appendix showing SCR magnitudes for the MISO Transmission Expansion Plan (MTEP) 2025, 2028, and 2033 cases. The Technical Appendix also contains sensitivities isolating the transmission and resource drivers over the planning horizon.

Shorter-term impacts on system strength are shown by comparing the 2025 summer model to the spring light load models (Figure 21), highlighting how voltage stability risks can change between seasons based on dispatch patterns. Different dispatch points warrant closer consideration, with a need to align planning models with actual operational conditions to better identify dispatch-related stability risks.

[34] Differences in resources between the MTEP23 2025 and MTEP23 2033 models could be attributed to resource additions, suspensions, outages, and retirements. For simplicity, these are labelled in Figure 20 as either an "Inverter-Based Resource Addition" or "Synchronous Generator Resource Retirement" to call out the locations of resource status changes driving SCR trends. However, the MTEP23 models used in this analysis are the same as those used in MISO's MTEP processes, following applicable procedures in BPM-020.

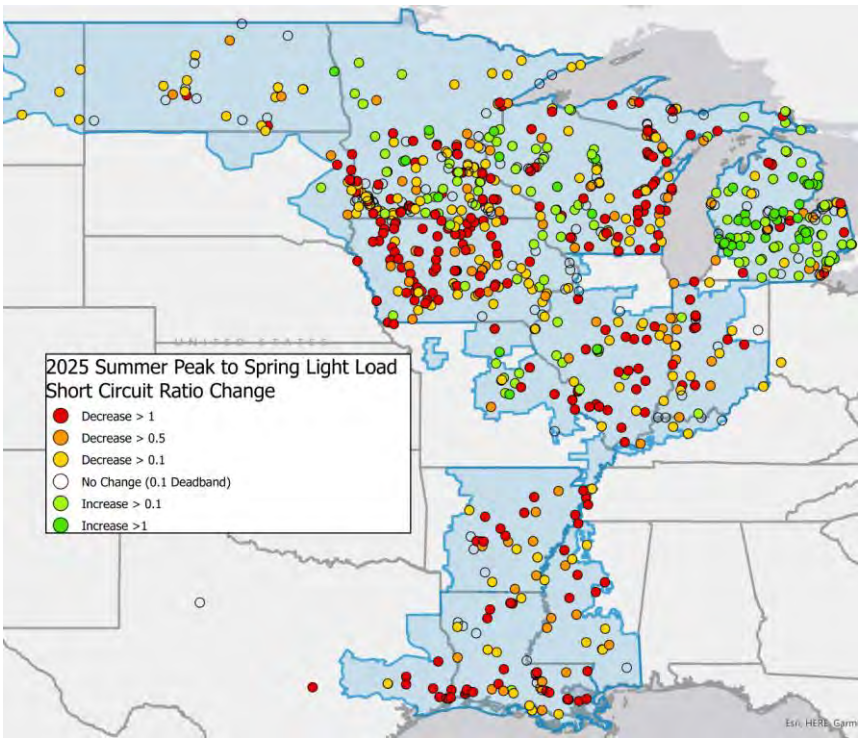


Figure 21: Change in short circuit ratio (SCR) between MTEP23 2025 summer peak and spring light load

INSIGHT: To gain greater visibility into potential voltage stability risks as the fleet transition accelerates, new scalable screening and analytics methods need to be developed

Given the localized and dynamic nature of voltage stability challenges, coupled with the granularity often required to model IBR control responses, screening accuracy at-scale becomes a significant challenge, especially for a system the size of the MISO footprint.

To illustrate this challenge, Figure 22 shows several methods for power system reliability analysis. The horizontal axis represents the study granularity or level of detail, and the vertical axis represents the level of effort, both human and computational, needed to support each tool. Increased granularity requires increased effort.

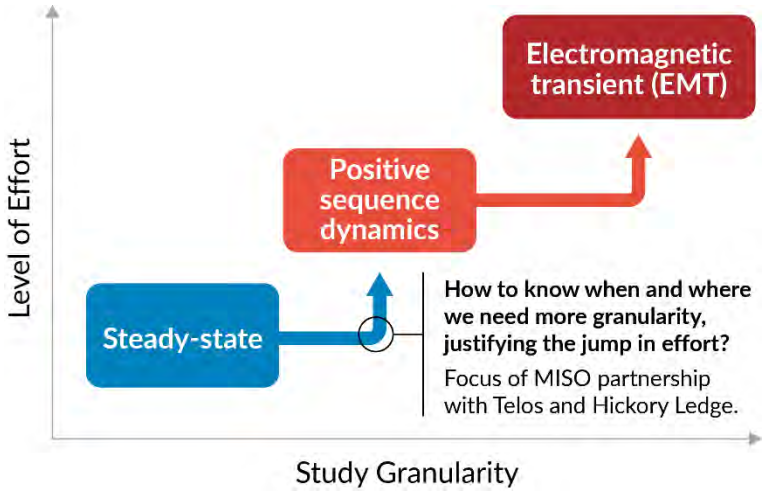


Figure 22: Illustration of effort-granularity tradeoff of common power system analysis tools

Steady state analysis is the simplest tool and can typically be performed for normal and contingency conditions at every bus location. However, steady state analysis does not provide the granularity or detail needed to understand potential dynamic voltage stability issues. A new tool is needed with practical consideration of the cost of the increased level of effort. Given the increased effort, it is typically not practical to perform more complex dynamic analysis at as many locations and under as many contingencies as the steady state analysis.

Any new approach must be scalable and accurately characterize different technology contributions to stability limits, especially given the wide range of responses from IBR's software-defined controls. In particular, the industry has recognized fundamental differences in so-called "grid-following" and "grid-forming" IBR controls.[35] Building on this understanding, MISO worked with energy consulting companies Telos Energy and HickoryLedge LLC to develop a repeatable analytical method to characterize these differences.[36] The results indicated that there are meaningful differences in the voltage support capabilities of different control types.

Figure 23 demonstrates results from the resource characterization approach using detailed electromagnetic transient (EMT) simulation on several commercially available grid-forming and grid-following inverters. The curves shown are composites from several different equipment models of that technology type and convey a typical response. Over the frequency range of interest, grid-forming controls appear to provide significant grid strengthening support capabilities, which can reduce voltage stability risks. The approach shows promise as an additional tool to characterize resources for the purpose of the simplified stability screening discussed in the next insight. Find additional details on resource characterization in section C.3.3 of the Technical Appendix.

[35] B. Kroposki *et al*., "Achieving a 100% Renewable Grid: Operating Electric Power Systems with Extremely High Levels of Variable Renewable Energy," in *IEEE Power and Energy Magazine*, vol. 15, no. 2, pp. 61-73, March-April 2017.

[36] M. Richwine *et al*., "Power System Stability Analysis & Planning Using Impedance-Based Methods," in 22nd Wind & Solar Integration Workshop, September 2023, *in proceeding*.

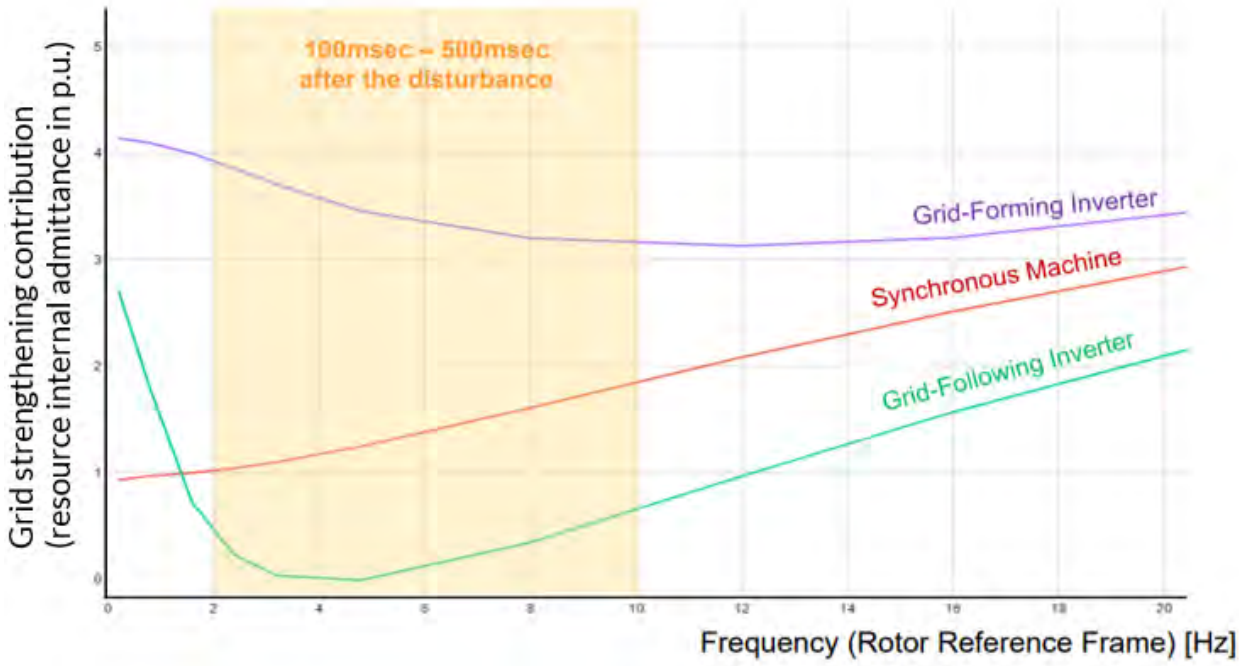


Figure 23: Resource characterization results from a series of detailed electromagnetic transient (EMT) simulations using detailed models. ***Image source: Telos Energy***

INSIGHT: MISO-funded research aligns with broader industry findings showing the promise of "grid-forming" controls to support voltage stability in resource portfolios with higher levels of inverter-based resources

Recognizing potential shortcoming of existing system strength metrics and approaches, MISO worked with Telos and HickoryLedge to develop and demonstrate 1) next-generation analytical screening approaches, and 2) indicative results comparing grid-forming and grid-following inverter controls. The resulting dynamic impedance approach builds on resource characterization described in the previous insight, feeding this information into existing MISO tools to assess dynamic voltage stability limits of different resource mixes. Figure 24 provides an overview of the resource characterization and dynamic impedance screening processes.

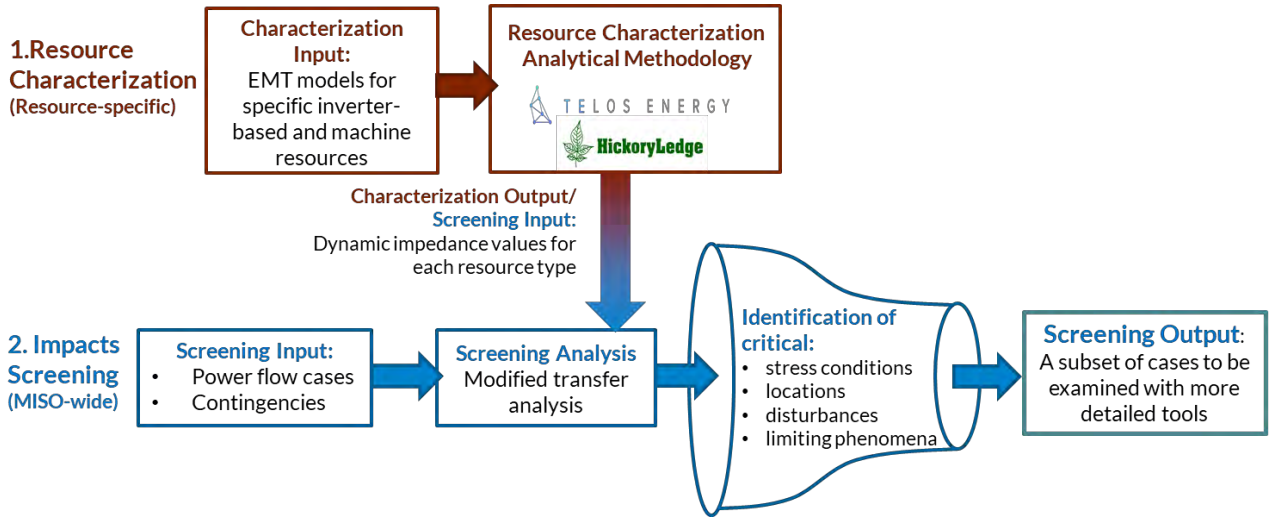


Figure 24: Overview of resource characterization and dynamic impedance screening process, described in greater detail in the Technical Appendix.

The dynamic impedance screening approach was used on the scaled-up MISO system to assess the effect of resource mixes dominated by high amounts of grid-following or grid-forming inverters on dynamic voltage stability limits.[37] A high IBR case with high levels of grid-forming controls was shown to increase the dynamic voltage stability limit by approximately 10% when compared to a similar case that had high levels of grid-following controls. The result demonstrates a stark contrast in system strength support capabilities between grid-forming and grid-following controls and indicate grid-forming controls will be an important part of the solution to counteract risks associated with declining system strength driven by traditional resource retirements.

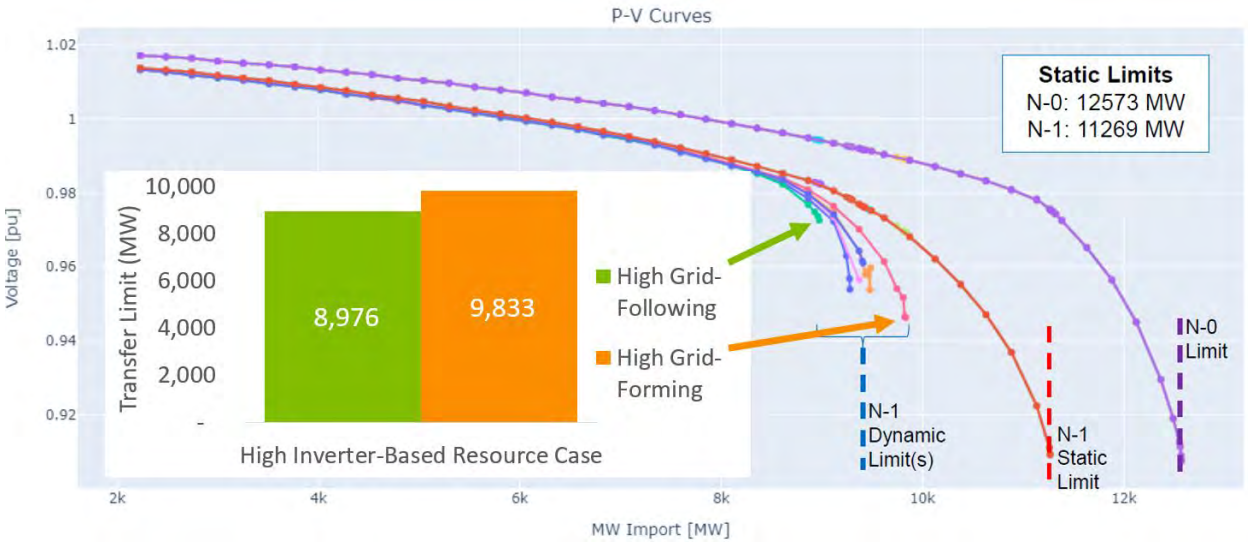


Figure 25: Dynamic impedance screening results comparing four select cases, varying IBR levels and grid-forming to grid-following proportions.

[37] Section C.3.3 in the Technical Appendix describes important caveats that place this demonstration assessing voltage stability limits in the realm of research and demonstration rather than conforming to typical reliability planning practices (e.g., TPL-001 contingencies).

Find a detailed explanation of the full voltage stability analysis and results in section C of the Technical Appendix.

SYSTEM STABILITY ATTRIBUTE RISK IS BEST ADDRESSED THROUGH PLANNING, REGULATORY SOLUTIONS, TECHNOLOGY STANDARDS, AND LOCALIZED COST-OF-SERVICE PROCUREMENTS, WHEN APPLICABLE

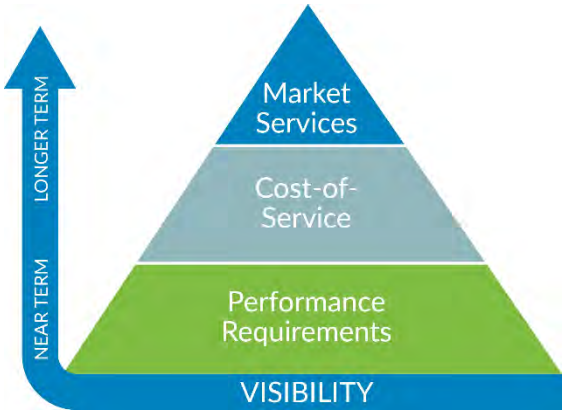
Stability challenges, including voltage stability, are best addressed in the planning timeframe by regulatory solutions because reactive deficiencies and solutions are highly localized. Obvious, low-cost solutions may be coordinated by technology standards and controls. Functionally, the types of solutions pursued should fit together in a way that drives efficiency and effectiveness, potentially forming a hierarchy (Figure 26).

Visibility: The development of new tools to provide clear visibility into localized voltage stability concerns is a prerequisite to forming any type of solution. Relatively few techniques exist for assessing large disturbance dynamic stability, and grid-following technologies appear to have a wide range of responses to more severe disturbances. Visibility examples include SCR screening, dynamic impedance screening, and critical clearing time screening.

Performance requirements: Build in voltage stability support through interconnection requirements applicable to all new resources, effectively minimizing the solution space required by other mitigations. Performance requirements should target control (i.e., software) capabilities without major cost implications. Examples include voltage ride-through, reactive current injection, and reactive power capability range.

Cost of service: Target specific needed capabilities that are outside of the standard set required for all resources. Cost of service solutions could include advanced functionalities that require additional conversion capacity or on-site energy storage.

Market services: Procure and dispatch services not met by a cost-of-service model. For instance, incentivizing the availability and delivery of stability services that an asset might otherwise withhold or not dispatch. While market services may ultimately be required in the long term, market solutions will be considered only after first exploring other options due to the localized nature of voltage stability issues.

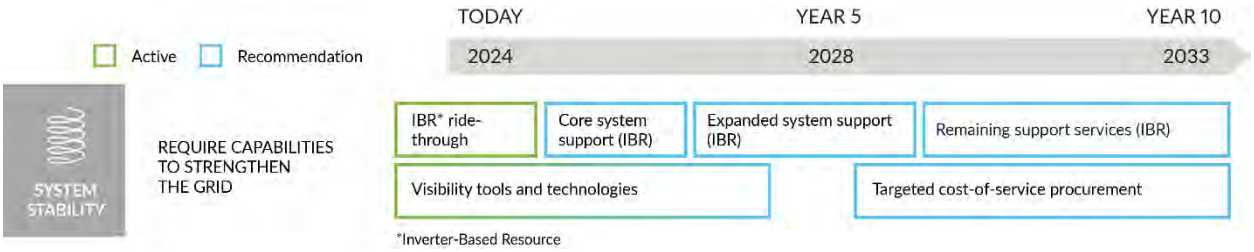


WHAT NOT TO DO NOW

Initial voltage stability issues are ineffectively addressed through market products given the local nature of the problem and solution and the subset of participants needed to engage with the issue. It has long been recognized that there cannot be a well-functioning market for reactive power like there can be for real

power; few jurisdictions have markets for reactive power services[38], other than incorporating voltage-based flow limits as MISO already does, and MISO is not aware of a large organized market with reactive power market products. MISO may revisit this solution in the future as these newer types of markets are demonstrated and refined on smaller island systems.

ROADMAP: REQUIRE CAPABILITIES TO STRENGTHEN THE GRID



[38] MISO's literature review found that Ireland's EirGrid has market services for reactive power. Further, the United Kingdom's National Grid Electric System Operator appears positioned to procure dynamic reactive power services. MISO did not view either of these island systems as directly comparable to the MISO context.

VOLTAGE STABILITY: Require capabilities to strengthen the grid
Require **ride-through capabilities** for interconnection of inverter-based resources (IBR) to address unexpected tripping • Adopt IBR performance from standard IEEE 2800 to keep resources online during a wider range of voltage and frequency disturbances • Address general IBR requirements (e.g., measurement accuracy, applicable voltages) to prepare for the adoption of future capabilities and performance requirements
Require **core system support** capabilities for interconnection of IBRs to support system stability more actively • Adopt high-level grid-forming performance requirements for energy storage systems, initially targeting "system strength" responses, with very fast resource reactive current controls • Expand adoption of IEEE 2800 to include voltage and frequency responses to support grid stability more actively under both normal and disturbance conditions. • Increase focus on assessing IBR plant conformance with sector partners
Require **expanded system support** with more active IBR controls to support a system with high levels of IBR • Adopt additional IBR performance requirements in IEEE 2800 which include very fast controls • Expand adoption of grid-forming performance requirements to include "synchronizing power" and "very fast frequency" (i.e., inertia-like responses) • Evaluate existing tool granularity and efficacy in assessing very fast IBR performance
Require **remaining support services** to enable an IBR-dominant system • Incorporate grid-forming black start capabilities so that IBR resources can qualify and contribute to re-energizing the system after major disturbances • Consider power electronic upsizing (i.e., inverter) to support system needs related to reactive fault current injection, black start, and system protection
Evaluate **targeted cost-of-service procurements** to incentivize other technologies and the "energy buffer" required for more advanced grid-forming IBR performance • Evaluate need for additional stability procurement requiring other technologies (e.g., static synchronous compensators, synchronous condensers, etc.) or upsized IBR hardware (e.g., inertia-like response, increased fault current) based on the impact of prior changes • Consider solution coverage over the broader range of stability issues – often categorized as voltage, frequency, angular, and converter-related – when evaluating cost of service solutions
Advance **visibility tools and technologies** to make visible of shifting risks and support further solution evaluation • Advance stability screening tools to better account for different types of IBR control responses • Continually refine grid-forming and grid-following model parameterization to match evolving performance requirements • Ensure appropriate model quality review procedures and tools are in place • Evaluate the need for limited electromagnetic transient (EMT) capabilities to evaluate grid-forming performance in the near-term and potentially expand to targeted system studies long-term • Consider additional needs for event recording technologies (e.g., digital fault recorders) to investigate events and validate models • Explore sensing and monitoring capabilities (e.g., phasor measurement units) for improved visibility of operational stability conditions

Table 5: Hypothesis solutions roadmap to proactively address voltage stability attribute risk by requiring capabilities to strengthen the grid.

MISO recommends IBR performance requirement adoption in four phases, each targeting specific ways in which grid-following and grid-forming IBR plants positively contribute to voltage stability. The phased design considers both reliability needs and industry readiness to install conforming plant equipment (Figure 27).

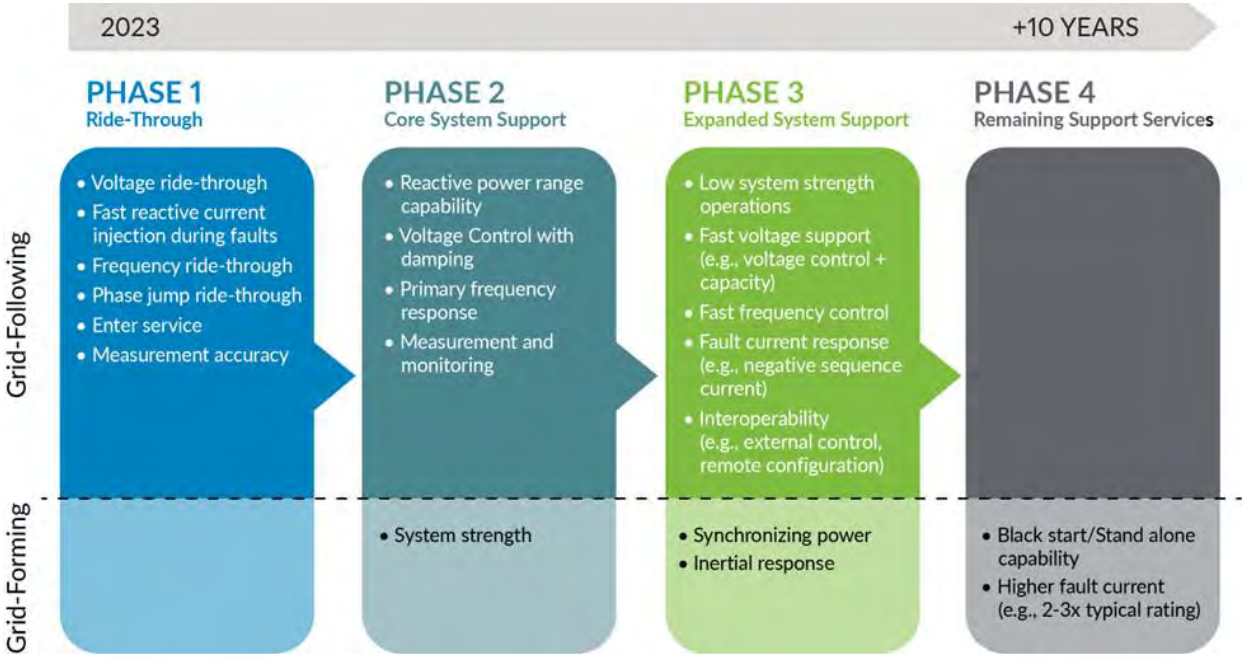


Figure 27: Summary of MISO's phased recommendation on grid-following and grid-forming capabilities and performance requirements

SOLUTION: Require ride-through capabilities for interconnection of inverter-based resources to address unexpected tripping

In January 2023, MISO embarked on a path to improve IBR performance requirements using a reliability risk-based approach to evaluate potential gaps in MISO's current Tariff. MISO shared the results of the risk assessment in March 2023 and finalized proposed tariff language in November 2023 to address the highest priority performance requirements and capabilities.[39] This proposal is Phase 1 of the recommended phased approach.

Performance requirements were prioritized based on whether they could address IBR tripping causes listed in eight recent NERC Disturbance Reports.[40] A supplemental source used for prioritization was the Federal Energy Regulatory Committee (FERC)'s IBR Notice of Proposed Rulemaking (NOPR) that led to Order 901, which in part directed NERC to develop standards to address the most significant IBR performance issues.[41]

The risk-based assessment found that the highest priority requirements were related to voltage support and dynamic responses. Priorities included frequency and voltage ride-through capabilities which require

[39] MISO, MISO proposed GIA redlines to incorporate IBR Performance Requirements, Planning Advisory Meeting Materials, November 15, 2023.

[40] NERC, Event Reports, accessed November 2023.

[41] FERC, Docket No. RM22-12-000; Order No 901. Issued October 19, 2023.

IBRs to stay connected during a range of disturbances, expanding on existing MISO ride-through requirements. Other priorities marked new capabilities, such as rate-of-change-of frequency ride-through and transient over-voltage ride-through, not contemplated in existing MISO requirements. Beyond ride-through, other capabilities identified as high priority for maintaining reliability include current injection during voltage ride-through and enter service criteria.

SOLUTION: Require core system support capabilities for interconnection of inverter-based resources to more actively support system stability

For Phase 2, MISO recommends developing grid-forming performance requirements for Battery Energy Storage Systems (BESS), targeting finalization of the performance capabilities by early 2025 with implementation timing determined with input from stakeholders. The grid-forming BESS requirements in Phase 2 aim to address strength support (i.e., fast reactive power support for voltage changes).

A NERC whitepaper released in September 2023 recommends that all newly interconnecting BESS should have grid-forming controls.[42] NERC also states that grid-forming requirements, testing procedures, policies, and/or incentives should be developed now for BESS and co-located resources with BESS. NERC suggests grid-forming BESS technology offers a low-cost opportunity to improve stability. MISO agrees with these recommendations and suggests phasing in grid-forming requirements through MISO's stakeholder processes.

Emerging grid-forming practices around the globe – *International grid operators overseeing resource transitions to high penetrations of IBRs have begun encouraging or requiring grid-forming capabilities from new resource interconnections. The Australian Energy Market Operator [1] and National Grid Electricity System Operator (NGESO)[1] have published voluntary grid-forming specifications, which are seen as a first step to contributing to stability support. Finland's Fingrid has released mandatory grid-forming specification that apply to only battery energy storage system (BESS) projects interconnecting in weak grid areas.[1] These early specifications focus on what some call "core" grid-forming capabilities, which are well-known capabilities that require no or minimal material modification to inverters compared to current grid-following practices.*

Regarding grid-following performance, MISO recommends expanding adoption of the IEEE 2800-2022[43] standard to include additional voltage and frequency capabilities and performance specifications to support grid stability more actively during normal operations (steady state) and disturbances (dynamic). These requirements could include reactive power range capabilities and voltage control with damping performance to support small signal voltage stability (e.g., sub-synchronous oscillations). In addition, MISO may recommend other performance not directly related to voltage stability, such as primary frequency response. Given the more active nature of some of these responses, additional supporting analysis is likely required, and MISO may consider recommending IEEE 2800 clauses related to measurement and monitoring to support performance monitoring and model validation.

[42] NERC. "White Paper: Grid Forming Functional Specifications for BPS-Connected Battery Energy Storage Systems", September 2023.

[43] IEEE, "IEEE Standard for Interconnection and Interoperability of Inverter-Based Resources (IBRs) Interconnecting with Associated Transmission Electric Power Systems", April 2022.

As IBR performance requirements continue to mature in the U.S., MISO recommends increased focus on assessing IBR plant conformance together with sector partners (interconnection customers, transmission owners, generator owners) and aided by international practices. MISO anticipates the future publication of draft standard IEEE P2800.2[44] will aide in defining conformance assessment best practices. Until then, MISO recommends working with the stakeholder community to define stopgap measures to ensure efficacy of performance requirements in place.

SOLUTION: Require expanded inverter-based resource performance to support a system with high levels of IBR

In Phase 3, the expanded system support performance requirement recommendations include adoption of remaining IEEE 2800 capabilities and performance; extending grid-following inverter requirements beyond current standards; and introducing additional grid-forming performance requirements for battery storage (BESS). These requirements start to extend stability support performance beyond strictly targeting voltage stability, which MISO recommends as additional attribute risk factors come into focus (e.g., declining system inertia).

Assuming no revision of IEEE 2800, additional performance capabilities recommended for adoption include fast frequency response, fault current response (e.g., negative sequence current), and expanded interoperability features (e.g., remote configuration). These expanded system support requirements come with more decision points and the potential for expanded analysis needs when compared to the earlier groupings of performance requirements. For instance, while IEEE 2800 offers different approaches for fast frequency response[45], industry research is still evaluating the use cases and effectiveness of these different options.[46] Considering additional grid-following capabilities, MISO will also consider recommendations that are not currently contemplated in IEEE 2800, such as defining a minimum level of system strength at which grid-following controls must be capable of stable operations.

Building upon grid-forming BESS recommendations established, MISO will expand performance requirements for this technology in Phase 3 to include expanded stability support features such as synchronizing power and very fast frequency response (i.e., inertia-like response). MISO anticipates additional detailed analysis will be required before enabling very fast frequency control to prevent unintended control interactions.

Lastly, MISO will assess industry readiness to expand grid-forming requirements to other IBR such as wind and solar resources without a storage component. MISO understands original equipment manufacturers are developing grid-forming capabilities for wind and solar plant equipment but have not publicly committed to timeframes when equipment may be available. MISO will continue to monitor industry control developments.[47]

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[44] IEEE. (Draft) *Recommended Practice for Test and Verification Procedures for Inverter-Based Resources (IBRs) Interconnecting with Bulk Power Systems*.

[45] IEEE 2800-2022 includes discussion on fast frequency response (FFR) proportional to frequency deviation, FFR proportional to the rate of change of frequency (df/dt), fixed magnitude FFR with frequency trigger (step response), fixed magnitude FFR with df/dt trigger.

[46] NREL, *Different Types of Fast Frequency Response from Inverter Based Resources*, October 2023.

[47] MISO participates in the universal interoperability for grid-Forming inverters (UNIFI) consortium and NERC's inverter-based resource performance subcommittee (IRPS), among other industry venues. UNIFI, *Specification for Grid-forming Inverter-Based Resources, Version 1*, December 2022. NERC, Inverter-Based Resource Performance Subcommittee (IRPS).

SOLUTION: Require remaining support services to enable an inverter-based-resource-dominant system

Preparing for a system with very high levels of load served by IBR, MISO's Phase 4 recommends incentivizing capabilities for remaining services that are primarily supplied by synchronous machines today. This largely translates to targeting black start and fault current needs which carry additional costs requiring incentivization.

MISO recommends defining grid-forming black start capabilities and performance requirements so that IBRs can qualify and contribute to re-energizing the system after major disturbances. Stakeholders and MISO may need to investigate potential barriers to IBR qualification as black start resources and consider options to allow resources with needed capabilities to participate.

Further, MISO recommends exploring inverter upsizing requirements needed for system support services related to reactive fault current injection, black start, and system protection (i.e., fault detection). Upsizing equipment drives increased capital costs, and potential operating and maintenance expenses, which would likely require incentives. Potential incentives are discussed further in the conditional solution section that follows.

SOLUTION: Evaluate targeted cost-of-service procurements to incentivize other technologies and the "energy buffer" required for more advanced grid-forming inverter-based resource performance

MISO anticipates that low-cost performance requirements, largely implementable through software-defined control changes, will provide only partial coverage of steady state and dynamic voltage stability needs. Additional assets are likely needed to address steady state reactive power and voltage damping requirements as well as fast active and reactive current responses.

A range of technologies are available to address voltage stability needs, including capacitor banks, static var compensators, static synchronous compensators (STATCOM), enhanced STATCOMs (i.e., on-board storage), high-voltage direct current (HVDC) terminals, and synchronous condensers. Each technology has unique technical and economic considerations. MISO recommends assessing applicable technology characteristics to gauge the potential role of each technology to mitigate stability risks and determine which assumptions to use in planning studies, should the technology be proposed as a potential mitigation measure. MISO may consider additional analysis to demonstrate potential roles for each technology. Such analysis should be coordinated with additional stability considerations (e.g., frequency, angular, converter-related). This was out of scope for this year's attributes effort.

Another cost-of-service mechanism may be required for IBR performance requirements that materially impact the capital or operating and maintenance costs for IBR plants. MISO suggests these additional costs are likely to materialize to address (1) IBR converter upsizing, and (2) "energy buffers."

Converter upsizing allows for higher instantaneous current injection which could be needed to support higher levels of steady state reactive power, reactive fault current injection, black start capabilities, and system protection needs (i.e., fault detection). The level of converter upsizing to support voltage stability would be based on site-specific assessments of system needs. Future long-range assessments could consider evaluating indicative magnitudes and potential locations of converter upsizing opportunities.

Energy buffers ensure active power can be supplied when needed, which can come in the form of storage or operating a plant below the maximum available power. Energy buffer requirements may require additional equipment, such as batteries or super capacitors, or missed opportunity costs for selling energy or providing ancillary services. Examples of services that may require an energy buffer could include synchronizing power and frequency responses.

SOLUTION: Advance visibility tools and technologies to improve transparency of shifting risks and support further solution evaluation

Building upon the 2023 work, MISO and stakeholders should consider options to advance stability screening tools to better account for different types of IBR control responses. MISO recommends continued development and evaluation of the dynamic impedance screening approach. In addition, other approaches beyond SCR (e.g., critical clearing time metrics adapted for IBR) should be considered. The objective is to have scalable approaches to accurately assess the various stability challenges that could emerge in a high IBR resource portfolio.

Future approaches should continue to refine selection of analysis tools (e.g., positive sequence dynamics versus electromagnetic transient) and IBR model parameterization to match evolving performance requirements and impact assessment needs. Recent NERC event reports have indicated that there are reliability risks associated with inaccurate models and insufficient tool granularity.[48] MISO recommends engaging stakeholders to ensure appropriate model quality review procedures and tools are in place within the generator interconnection process.

MISO also recommends investigating the need for limited EMT simulation capabilities to evaluate grid-forming functional performance in the near term and potentially expanding to targeted system studies in the future. EMT capabilities are also needed for resource characterization within the dynamic impedance screening approach. NERC and industry have recognized the need for model quality verification procedures, especially when using EMT models. MISO recommends working with stakeholders to explore the need for standardized model quality review procedures, both for positive sequence dynamics models and EMT models, to the extent each type of model is required.

Lastly, MISO recommends investigating the need for operational sensing and monitoring technologies to improve visibility in the operating horizon and for use in post-event investigations. As an example, MISO recommends working with stakeholders to consider additional needs for event recording technologies (e.g., digital fault recorders) to investigate events and validate models. Further, MISO and stakeholders should explore sensing and monitoring capabilities (e.g., phasor measurement units) for improved visibility of operational stability conditions across a wide area.

SYSTEM STABILITY ANALYSIS NEXT STEPS

Future investigations into voltage stability risks and solutions could target questions such as:

- What proportion of new IBR should be grid-forming, and at what locations, to support reliability and reduce overall system costs?

[48] NERC, *2022 Odessa Disturbance*, December 2022.

- What mix of other technologies (BESS, enhanced STATCOM, synchronous condensers, etc.) best supplements advanced IBR controls for stability support?
- How much energy buffer is needed for certain grid-forming capabilities (e.g., synchronizing power)?
- How much converter upsizing is needed to meet stability or system protection needs?
- How do different types of loads (e.g., high vs low inertia loads) effect the performance of grid-forming, grid-following, and different combinations of these controls?

Acknowledgments

MISO thanks The Brattle Group, Telos Energy, and HickoryLedge LLC for their contributions to this effort.

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The latest status of MISO's attributes-related work can be found on MISO's Dashboard for "Identification of Sufficient Reliability Attributes RASC – 2022-1." Ongoing stakeholder discussions will be coordinated through the MISO Stakeholder Resource Adequacy Subcommittee.

Acronyms

AEMO: Australian Energy Market Operator

BESS: Battery Energy Storage System

CCGT: combined-cycle gas turbine51

CVaR: Conditional Value at Risk

DER: Distributed Energy Resource

DLOL: Direct Loss of Load

EGRET: Electric Grid Research & Engineering Tool

EMS: Energy Management System

EMT: Electromagnetic Transient

EPRI: Electric Power Research Institute

EUE: Expected Unserved Energy

FERC: Federal Energy Regulatory Commission

GFL: Grid Following

GFM: Grid Forming

HVDC: High Voltage Direct Current

IBR: Inverter-Based Resource

IEEE: Institute of Electrical and Electronics Engineers

IMM: Independent Market Monitor

LAC: Look-Ahead Commitment

LMR: Load Modifying Resource

LOLE: Loss of Load Expectation

LOLH: Loss of Load Hours

MISO: Midcontinent Independent System Operator

MTEP: MISO Transmission Expansion Plan

NERC: North American Reliability Corporation

NOPR: Notice of Proposed Rulemaking

NSI: Net Scheduled Interchange

PRA: Planning Resource Auction

PRM: Planning Reserve Margin

PRMR: Planning Reserve Margin Requirement

RAN: Resource Availability and Need

RBDC: Reliability-based demand curve

RDT: Regional Directional Transfer

RIIA: Renewable Integration Impact Assessment

RRA: Regional Resource Assessment

RTO: Regional Transmission Organization

SCR: Short Circuit Ratio

STATCOM: Static Var Compensators, Static Synchronous Compensators

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

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

Exhibit 86
MISO Attributes Roadmap Technical Appendix

Technical Appendix: Attributes Roadmap

Version Number	Purpose / Change	Date
1.0	Initial posting.	December 2023
1.1	Updated with hyperlinks between the *Technical Appendix* and the *Attributes Roadmap* per stakeholder feedback.	June 2024

Introduction

This technical appendix provides a detailed discussion of the data inputs, analytical tools, methods, modeling assumptions and results that support the insights presented in MISO's 2023 *Attributes Roadmap*. The analysis of current and future portfolios informed the selection and prioritization of the solution hypothesis in that document.

MISO's attributes effort began by studying industry research and the experiences and approaches of other grid operators facing similar challenges. This landscape review, in addition to MISO's past analyses and experiences, led to the identification of three priority system attributes where near-term risk for the MISO system is most acute: system adequacy, flexibility, and system stability (Figure 1).

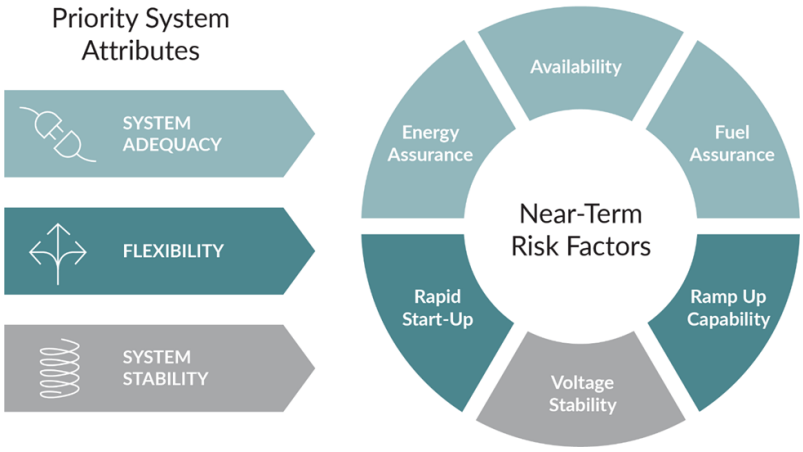


Figure 1. Three priority system attributes and near-term risk factor focus areas

System Adequacy is the ability to serve load in all realistic scenarios, including the most challenging periods, by having enough supply to meet demand when and where it is needed. Generation capacity is considered when measuring this attribute, as well as actual availability every hour of the year. As the system adds more weather-dependent generators, the risk hours shift away from the traditional summer peak and increasingly to non-summer months. Maintaining reliability through multi-day periods of low renewable resource output, or correlated outages due to fuel supply or utilization issues presents new and additional energy and fuel assurance risk factors.

Flexibility is the ability to meet the ramping needs of the system with multiple response timeframes and durations. As generation becomes more weather-dependent and electrification trends change traditional load patterns, the complexity of forecasting and operations increases significantly, leading to greater system uncertainty and variability. MISO has identified rapid start-up and ramp up capability as near-term risk factors, but flexibility in a broader sense includes ramp rates, shut-down times, and minimum generation levels. A more flexible future system will be required to meet the emerging challenges and ensure reliability while maximizing economically efficient operations and system investments.

System stability is the ability to remain in a state of operating equilibrium under normal conditions and to recover from disturbance events, including unplanned generation outages and rapid changes in generation output driven by changing weather. MISO identified voltage stability as the nearest term stability risk. Voltage stability is often thought of as load-driven rather than resource-driven, though resource characteristics affect stability outcomes. The addition of inverter-based resources and retirement of resources that historically provided sufficient reactive power, requires a new approach to ensure ongoing reliability and stable outcomes.

Over the course of 2023, MISO has designed and performed foundational quantitative analyses to gain improved insights and understanding to better describe and define the system attributes today and under five-year and 10-year future scenarios. The team studied potential market reforms from two perspectives: (1) the planning horizon (long-range investment and retirement timeframe) where the risk is not having sufficient resources, and (2) the operating horizon (near real-time timeframe) where the risk is not using available resources efficiently.

This technical appendix summarizes this effort and is organized in the following sections:

A. System Adequacy

B. Operational Adequacy

C. Voltage Stability

D. Attribute Support from MISO's Market Structures

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Table of Contents

A. System Adequacy 4
A.1 Methodology 4
A.1.1 Resource Adequacy Analysis 4
A.1.2 Tools 5
A.1.3 Datasets 5
A.1.4 Accreditation 5
A.2 Study Years and Data Sources 6
A.2.1 PY23-24 Base Model 7
A.2.2 Future 2A Base Model 8
A.3 Scenarios 13
A.3.1 Business as Usual 13
A.3.2 Enhanced Risk Assessment (ERA) 14
A.3.3 Adequacy-Flexibility Constraint 15
A.4 Results 15
A.4.1 Business as Usual 15
A.4.2 Enhanced Risk Assessment (ERA) 18
A.4.3 Adequacy-Flexibility Analysis 22
A.5 Conclusions 25

B. Operational Adequacy 26
B.1 Framework for Market Simulations 26
B.1.1 Tool 26
B.1.2 Metric 26
B.1.3 Two-Stage Simulation Framework 26
B.1.4 Screening Methodology for Stressed Periods 28
B.2 Scenarios 28
B.3 Future Portfolio Assumptions 29
B.3.1 Data Inputs and Assumptions 29
B.3.2 Methodology for Forecast Uncertainty Assumptions 30
B.4 Results 31
B.5 Conclusions 39

C. Voltage Stability 40
C.1 Voltage Stability Definition 40
C.2 Current State of the MISO system 41
C.2.1 Renewable Integration Impacts Assessment 41
C.2.2 Planning 43
C.2.3 Operations 45
C.2.4 Markets 45
C.3 Attributes Voltage Stability Analysis 45
C.3.1 Limitations of Screening Tools 45
C.3.2 Short-Circuit Ratio 45
C.3.3 Dynamic Impedance Method 53
C.4 Conclusion 60

D. Attribute Support from MISO's Market Structures 61

A.System Adequacy

This section of the appendix provides supplemental information on the analysis described in the System Adequacy section of MISO's 2023 *Attributes Roadmap*. The analysis informs the development of the solution hypothesis by quantifying the impact of emerging risk factors (availability, energy, and fuel assurance) on MISO-wide accreditation and planning requirements using a resource adequacy analysis that follows best practices. This analysis also explored the implications of including operational constraints in resource adequacy models. This approach was used to analyze both the current portfolio and future portfolios using MISO's Future 2A[1].

A.1 Methodology

A.1.1 Resource Adequacy Analysis

Resource adequacy analysis, as required by the North American Electric Reliability Council (NERC) Standard BAL502-RFC-0211, aims to ensure sufficient installed generation capacity to meet electric load, measured against a prescribed target. The objective of the resource adequacy analysis in the System Adequacy portion of the Attributes work is to understand how the risk of unserved energy changes with the evolving resource mix over the next decade. The resource adequacy analysis aims to identify changes to the planning reserve margin requirement (PRMR) and accreditation of resources through the direct loss of load (DLOL) method[2]. As the resource mix rapidly changes with the addition of renewable and storage resources, it becomes clear that these resources play an important role in serving load and maintaining system reliability. The stochastic and energy-limited nature of these resources result in changes to the reliability risk profile and a shift in the probability of loss of load to periods outside of the traditional risk periods.

The System Adequacy analysis uses a seasonal resource adequacy construct to estimate DLOL using MISO's currently established metric of a loss of load expectation (LOLE) of 1 day in 10 years. The LOLE analysis uses a sequential Monte Carlo simulation to model a wide range of system conditions and assess the system's reliability. The LOLE analysis is a chronological, 8,760-hour simulation and includes multiple weather years. Multiple samples are developed for generator forced outage profiles for each weather year. LOLE, and other metrics, are calculated using an average across samples and weather years.

To capture the interannual variability of weather-related patterns, synchronized load, wind, and solar hourly datasets were used for the study. Thermal outages are accounted for in the form of planned and forced outages. The former is determined by the maintenance rate and mean time to repair while the latter uses the forced outage rate. In summary, the analysis considers the variability of load, wind, and solar output along with planned maintenance and forced outages of generation units. The modeling inputs vary slightly from the standard business practice to incorporate the expanded scope of the attributes work.

Following current practices at MISO, the LOLE model was adjusted and brought to criteria. First, the simulation is run without any adjustments and the resulting natural LOLE is determined. Next, annual adjustments are performed by adding or removing fixed load so that the average LOLE across all weather years reaches 0.1 days/year. For seasons with no LOLE resulting from this process, seasonal adjustments are then made to the system until each season results in a LOLE of at least 0.01 days/year. If the LOLE is less than the target for a season, then fixed load is added to the model. If the LOLE is greater than the target for a season, then proxy combustion turbine generators

[1] MISO, *MISO Futures Report, Series 1A*, November 2023.

[2] MISO, *Resource Accreditation White Paper, Version 1.1*, November 2023.

with a size of 160 MW and class average equivalent forced outage rate (EFORd) are added to the model until the seasonal LOLE target is achieved.

A.1.2 Tools

The Planning Adequacy analysis uses a program developed by Energy Exemplar called PLEXOS to perform the resource adequacy assessment. The PLEXOS model is a probabilistic, hourly chronological simulation over the study year, which uses the sequential Monte Carlo method to develop random forced outage samples. Planned thermal outages are determined by the maintenance rate and mean time to repair, while forced outages use historical forced outage rates. Both the planned maintenance and sequential Monte Carlo are based on optimization techniques.

A.1.3 Datasets

In Planning Adequacy analysis, weather-dependent characteristics of load, wind and solar generation, and extreme weather-dependent thermal generation outage were collected to represent the diverse operating conditions. For the PY23-24 model, the 2022 Regional Resource Assessment (RRA) model was aligned with MISO's LOLE study[3] model. The equivalent datasets for F2A 2027 and 2032 models are sourced as below:

- Load: Actual load recorded for the operation years 2007-2021 was collected and scaled based on energy and capacity peaks specified by MISO Future 2A's assumptions[4].
- Wind and solar generation: For all existing and planned siting, hourly forecasted generation was calculated based on each siting's geographical location, using National Renewable Energy Laboratory's (NREL) and Vibrant Clean Energy's dataset of weather years 2007-2021. The generation was aggregated per Local Resource Zone (LRZ) for the simulations.
- Extreme weather-dependent thermal generation outage: Temperature- and fuel-dependent outages were analyzed to create hourly correlated outages, scaled to the capacity of thermal generation in each model.

A.1.4 Accreditation

In addition to examining how risk evolves in LOLE models under different assumptions, MISO studied the impact on the capacity value of different resources. Accreditation estimates were calculated for different resource classes and followed MISO's DLOL class accreditation proposal,[5] as of September 2023. The DLOL method calculates a resource's resource adequacy contribution by measuring its ability to serve load during times of system shortfall events in the LOLE model.

Resource availability during modeled loss-of-load hours, across all samples, is aggregated by resource class. Average class-level availability is averaged by season and load forecast error (LFE) tranche, and the weighted average across LFE tranches results in the DLOL in MW terms. To express DLOL as a percentage, the available DLOL MW is divided by the resource class installed capacity. The standard MISO resource adequacy LOLE model includes the effect of LFE, but that feature was excluded from this analysis to reduce the amount of processing required for the scenarios in this analysis. Therefore, DLOL results in this study are not weighted by LFE probabilities. Similarly, the non-thermal technologies were aggregated into a single class for reporting purposes. Figure A-1 presents the DLOL calculation process as shown in MISO's accreditation white paper, which includes the LFE tranche steps.

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[3] MISO, *Planning Year 2023-2024 Loss of Load Expectation Study Report*, Updated May 2023.

[4] MISO, "Future 2A Energy Adequacy and Siting", Presented at MISO's LRTP Workshop, April 28, 2023.

[5] MISO, *Resource Accreditation White Paper, Version 1.1*, November 2023.

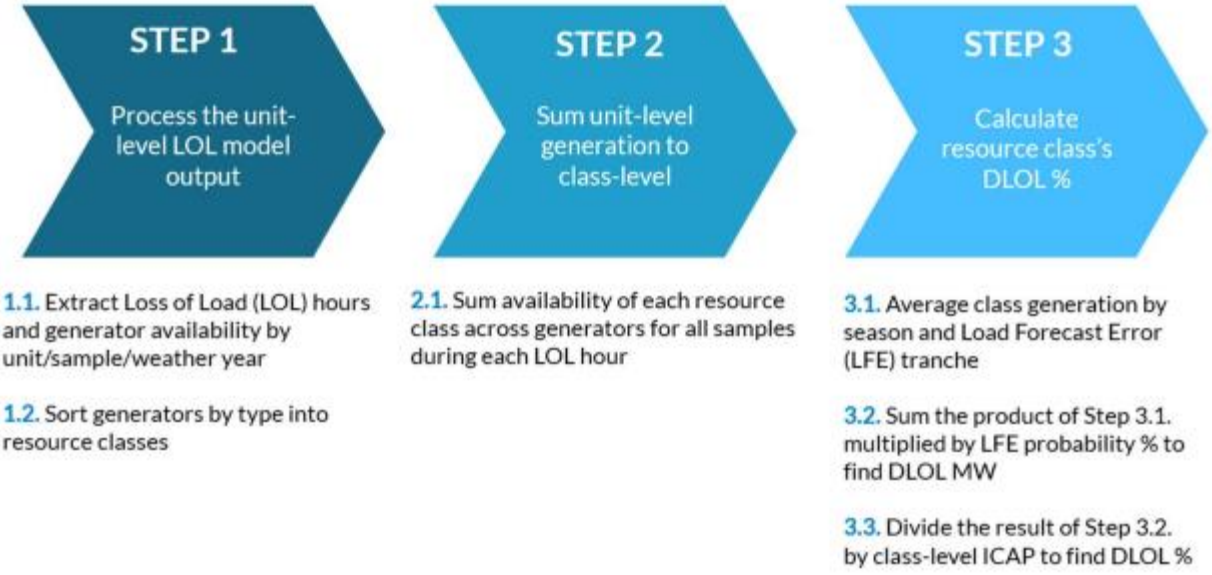


Figure A-1: DLOL calculation process from MISO's Resource Accreditation White Paper (v1.1)[5]

A high-level verification was performed to compare the outcomes of the planning year 23-24 (PY23-24) LOLE Study[6] and this work. Inputs were aligned as much as possible, but the use of different tools and techniques lead to small differences in the results[7].

A.2 Study Years and Data Sources

The System Adequacy analysis was designed to cover the energy transition that is expected to occur over the next decade to inform near term decisions about actions MISO should take to ensure system reliability attribute sufficiency. To that end three study years were selected: PY23-24, the year 2027, and 2032. Figure A-2 summarizes the major assumptions for these years. The first year was intended to represent current system conditions and its assumptions are aligned with the PY23-24 LOLE Study[8]. 2027 and 2032 represent medium- and longer-term forecasts and they are consistent with the Future 2A expansions in the MISO Futures Report[9].

[6] MISO, "Market Redefinition: Accreditation Reform", slide 6, presented at MISO's RASC, October 4, 2023.

[7] A benchmark of the results was shared at MISO "System Reliability Attributes Analysis and Roadmap Workshop #2" presented at MISO's RASC workshop, October 31, 2023.

[8] MISO, *Planning Year 2023-2024 Loss of Load Expectation Study Report*, Updated May 2023.

[9] MISO, *MISO Futures Report, Series 1A*, November 2023.

PY23-24	•Probabilistic model •PY23-24 LOLE Study as basis for resource portfolio and load •30 weather years (1992-2021) •125 random outage samples per weather year
2027 & 2032	•Probabilistic models •Future 2A expansion as basis for resource portfolio and load •15 weather years (2007-2012, 2014-2021) •250 random outage samples per weather year •Load includes electrification and energy efficiency forecasts

Figure A-2: Main assumptions and sources by study year

The transition in the resource mix is presented in Figure A-3, which highlights the increase in variable renewable generation, coupled with the retirement of coal generation. The remainder of this subsection presents more details on the assumptions used across the study years, including those that lead to the capacity mix presented in the figure.

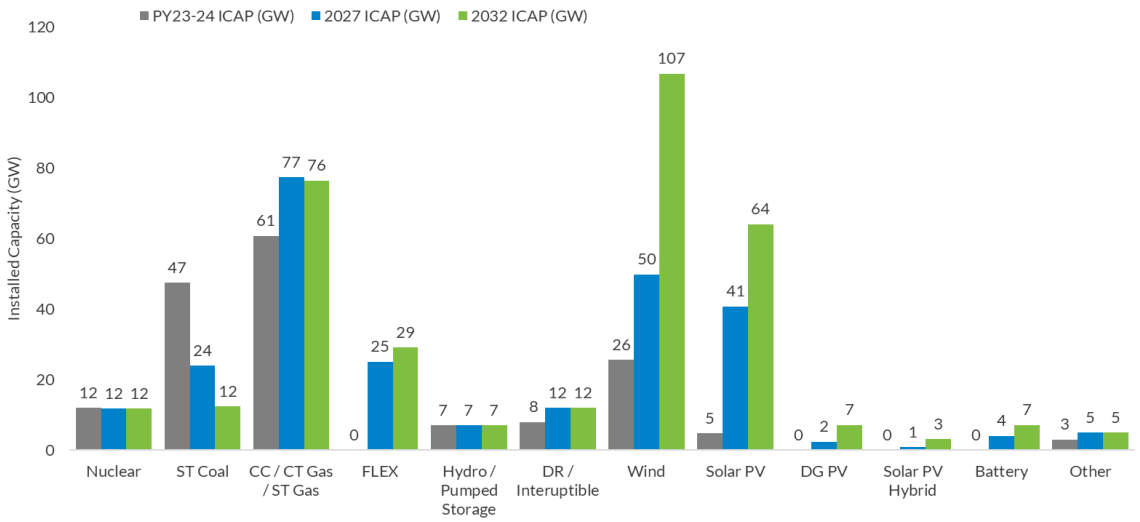


Figure A-3. Capacity mix assumed for the three study years

A.2.1 PY23-24 Base Model

The basis for the model in PLEXOS was the 2022 Regional Resource Assessment (RRA)[10], but data used for MISO's PY2023-2024 LOLE study[11] was incorporated into the PLEXOS model for the current year analysis. The study used 125 samples per weather year, and 30 weather years were included (1992-2021).

[10] MISO, *Technical Appendix: RRA Assumptions and Methodology*, from MISO, *2022 Regional Resource Assessment*, November 2022.

[11] MISO, *Planning Year 2023-2024 Loss of Load Expectation Study Report*, Updated May 2023.

Load

Hourly load data for each LRZ for each weather year was taken from the PY23-24 LOLE Study.

Generation

Installed capacity (ICAP) values were adjusted from 2022 RRA values to match the PY23-24 capacity values.

Seasonal forced outage rates (FOR) were incorporated into the model. These values were taken from the PY23-24 LOLE study on a unit-by-unit basis when units could be mapped, otherwise class average values were used. Mean, minimum, and maximum time to repair for forced outages were taken from the 2022 RRA, which used 2013-2018 GADS data.

Annual maintenance rates from the 2022 RRA were used in the model. Maintenance was scheduled in one event per unit per year using daily peak load resolution.

Renewable Profiles

Solar and wind profiles for each LRZ for each weather year were taken from the PY23-24 LOLE Study.

External Units (Firm and Non-Firm)

Non-firm external imports were included in the model, following the distribution in Table 3-5 from the PY23-24 LOLE study.

Firm external generation units were also included in the model from the PY23-24 LOLE study. PY23-24 data for the specific units was used for ICAPs, FORs, forced outage mean time to repair, and maintenance rates. Class averages from the F2A data were used to assign fixed operation and maintenance cost, variable operation and maintenance, and heat rates for each external unit.

A.2.2 Future 2A Base Model

The 2027 and 2032 generation portfolios were taken directly from the Future 2A (F2A) output[12], so most assumptions about generation mix match those in the Futures assumptions documents. 250 samples were used per weather year.

Load

F2A load was the basis for load assumptions. Applied Energy Group (AEG) provided the MISO Futures group with annual peak load and annual energy data, that were based upon State Utility Forecasting Group values from the Futures Series 1. The base weather year for F2A load was 2018, and to provide load shapes for weather years 2007–2012 and 2014 – 2021, historical hourly load was gathered and scaled. Next, AEG's electrification, energy efficiency, and demand side management assumptions were adjusted to align days of the week with each historical weather year to develop an electrified load shape for each weather year. Each electrified weather year was then shaped in PLEXOS to reach the F2A zonal peak and annual energy assumptions. Figure A-4 presents two weather year samples for modeled, final load, and Table A-1presents 2027 and 2032 annual energy and zonal peak assumptions.

[12] MISO, *LRTP Tranche 2 – Futures Refresh, Assumptions Book*, Updated April 2023

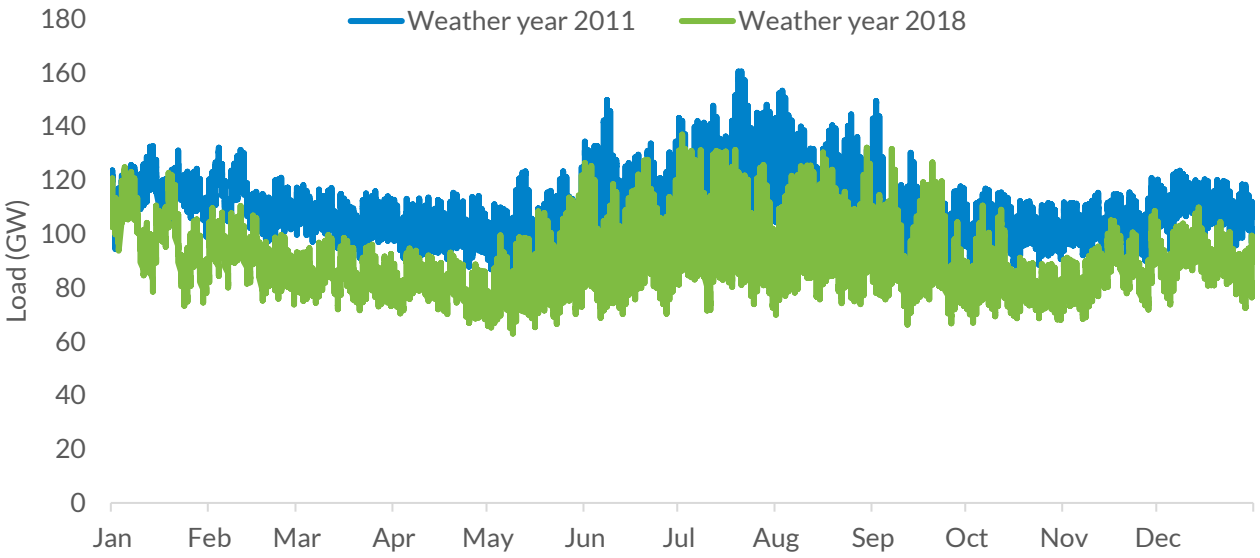


Figure A-4: Sample MISO-wide load profiles for study year 2027

LRZ	Annual Energy (GWh)		Annual Zonal Peak (MW)	
	2027	2032	2027	2032
LRZ 1	114,950	123,255	19,576	20,945
LRZ 2	73,097	80,374	13,268	14,578
LRZ 3	57,446	62,123	10,190	10,843
LRZ 4	55,684	59,790	10,222	10,909
LRZ 5	42,830	45,890	8,655	9,080
LRZ 6	113,354	121,692	19,718	21,207
LRZ 7	118,702	127,942	23,129	24,374
LRZ 8	44,109	45,961	8,527	8,964
LRZ 9	138,646	144,936	22,703	23,773
LRZ 10	24,297	24,950	4,756	4,851

Table A-1. Future 2A annual energy (GWh) and annual zonal peak demand (MW)

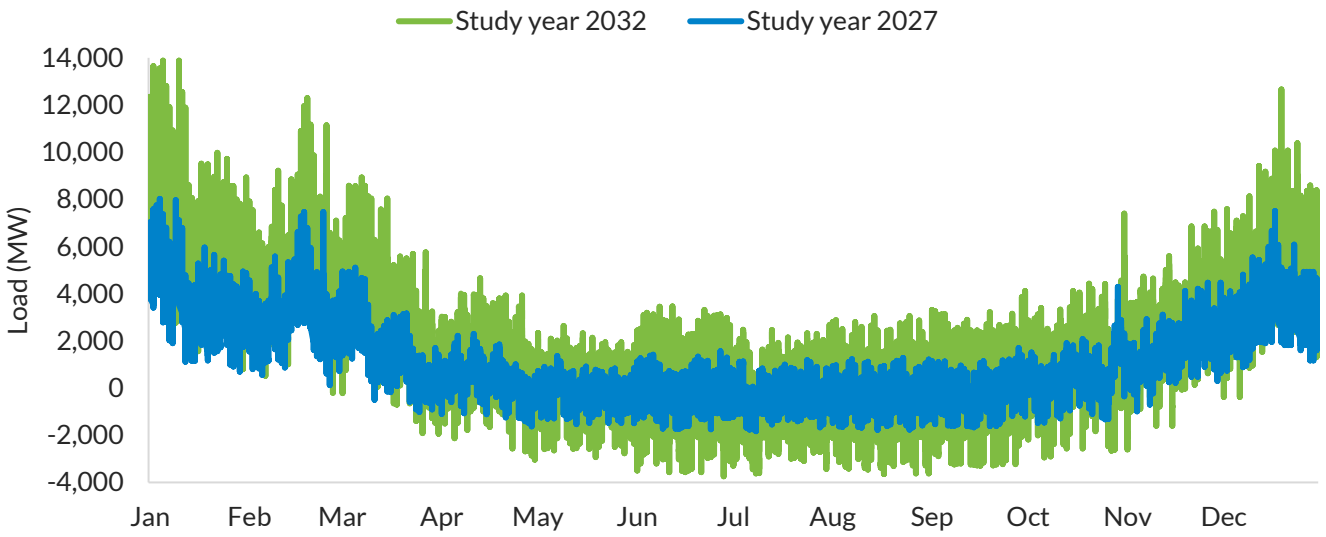


Figure A-5: MISO-wide net electrification (electric vehicle and building electrification load minus energy efficiency)

Generation

Generator capacities and retirement/installation dates were taken from the F2A expansion.

Seasonal FORs were incorporated into the model, along with annual forced outage mean time to repair (MTTR). These values were taken from the PY23-24 LOLE study on a unit-by-unit basis for existing units, and class averages by LRZ were used to assign FORs to future thermal units. FLEX units in the F2A model were assumed to have FORs similar to combustion turbine units.

Annual maintenance rates were incorporated into the model. These values were taken from the PY23-24 LOLE study on a unit-by-unit basis for existing units, and class averages by LRZ were used to assign maintenance rates to future thermal units. FLEX units in the F2A model were assumed to have the maintenance rates of an average gas combustion turbine unit. Maintenance was scheduled in one event per unit per year, matching PY23-24 LOLE study assumptions.

FORs were used and maintenance was scheduled for all unit types except the following:

- Demand response
- DG photovoltaic (PV)
- Interruptible
- Solar PV
- Solar PV Hybrid
- Wind
- Batteries

Additional generator properties were included for thermal units from F2A data. Unit-specific data was used for fixed operation and maintenance cost, variable operation and maintenance cost, heat rates (not used for hydro), and monthly maximum rating values.

Hybrid Units

For hybrid units, 70% of the capacity defined in F2A was assumed to be PV and 30% of the capacity was assumed to be battery. This matches the assumptions used in the 2022 Regional Resource Assessment.

Additionally, there were two constraints for hybrid units implemented in the model. The first is a point of interconnection constraint, which ensures that the solar output and battery output combined cannot be greater than the total hybrid unit capacity at any given time. The second constraint is that the battery portion of the hybrid unit can only charge from the output of the PV portion of that unit.

Specific assumptions relating to batteries, both stand-alone and hybrids, are listed in Table A-2.

Consideration	Modeling Assumption
Battery Capability	Four-hour discharge capability at rated output
Battery Efficiency	Charging efficiency 85% and discharging efficiency 100%
State of Charge	Initial SOC set at 100% and changes as a function of dispatch decisions. Does not reset at the beginning of each day.
Operation	Maximize contribution during loss of load events.
Charging Source – Stand-Alone Battery	Battery can charge from the grid.
Charging Source – Hybrid Battery	Battery component may only be charged from solar PV and not directly via grid.

Table A-2. Modeling assumptions used for stand-alone and hybrid batteries.

Renewable profiles

Hourly wind energy production profiles were gathered from NREL's Wind Integration National Dataset (WIND) Toolkit for the years 2007-2012. Solar data was sourced from NREL's Solar Integration National Dataset (SIND) Toolkit for the same years. Additional data was supplied by Vibrant Clean Energy for the years 2014-2021.

Each wind and solar resource were assigned specific energy-production profiles based on their location, one profile with hourly granularity for each of the 14 years (2007-2012, 2014-2021) studied. Exact latitude and longitude data for future units came from the F2A siting. Exact location data for existing units came from PROMOD when available or was otherwise manually approximated.

Figure A-6 and Figure A-7 present sample MISO-wide solar and wind profiles, respectively, for study year 2027.

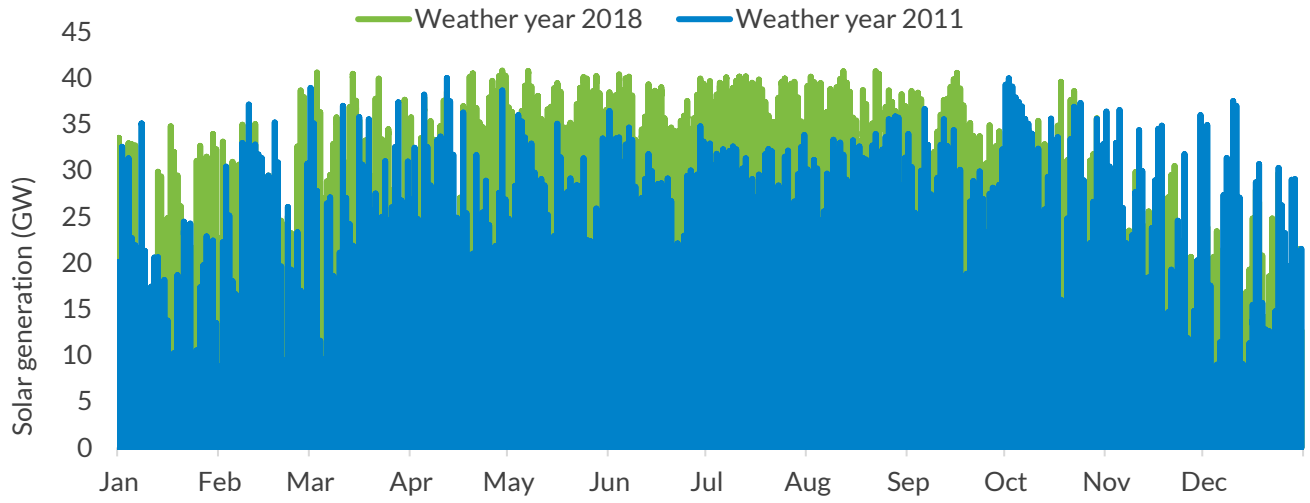


Figure A-6: Sample MISO-wide solar profiles for study year 2027

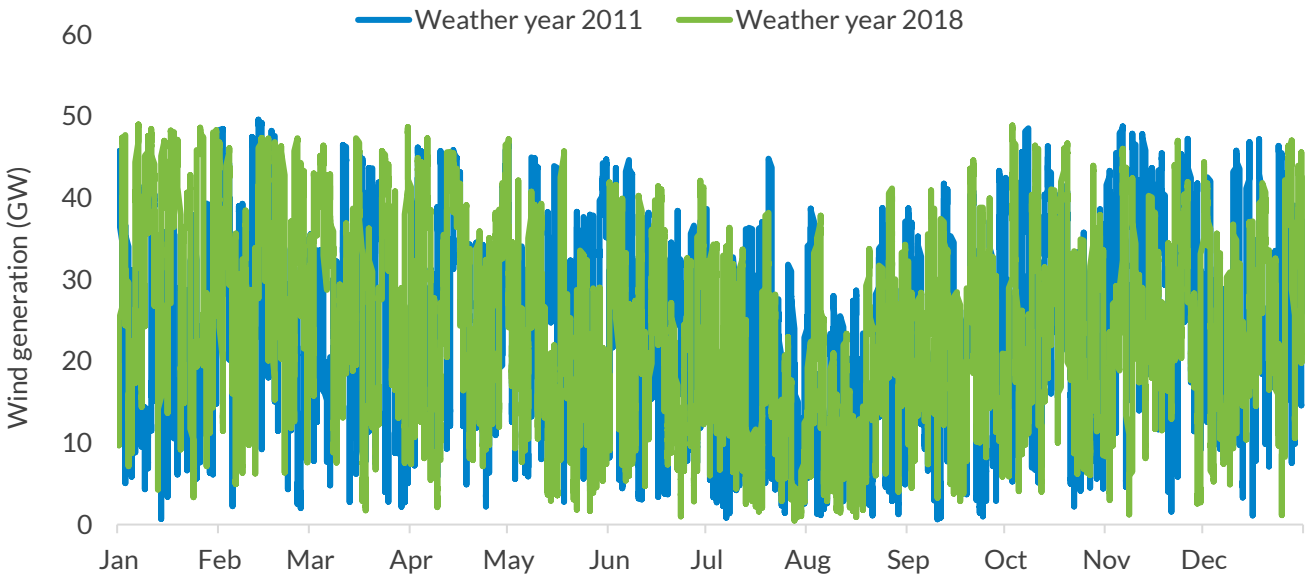


Figure A-7: Sample MISO-wide wind profiles for study year 2027

External Units (Firm and Non-Firm)

Non-firm external imports were included in the model, following the distribution in Table 3-5 from the PY23-24 LOLE study.

Firm external generation units were also included in the model from the PY23-24 LOLE study, and data for the specific units was used for monthly ratings, forced outage parameters (rates and mean time to repair), and maintenance rates. Class averages from the F2A data were used to assign fixed- and variable-operation and maintenance costs, and heat rates for each external unit.

A.3 Scenarios

The model year portfolios were analyzed under three scenarios: business as usual (BAU), enhanced risk assessment (ERA), and flexibility. Figure A-8 summarizes the design behind these three scenarios and how they align with the overall risk factors in the Attributes framework.

- **Business as usual (BAU)**
  - Aligns with base business RA modeling practices and includes cold-weather dependent thermal forced outages
  - *Risk factors:* Availability and Fuel Assurance
- **Enhanced risk assessment (ERA)**
  - Add regional directional transfer (RDT) constraint between MISO North/Central and South, heat rates, fuel prices, and price-responsive storage dispatch to the BAU scenario
  - *Risk factors:* Availability, Fuel Assurance, and Energy Assurance
- **Flexibility**
  - Add generator ramp rates (MW/min) and minimum stable levels to the BAU scenario
  - *Risk factors:* Availability, Fuel Assurance, Rapid Start-Up, and Ramp Up

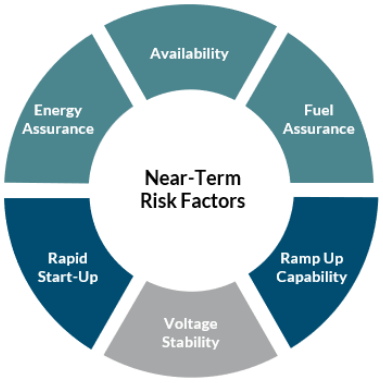


Figure A-8: System adequacy risk factor scenarios

The rest of this subsection introduces the specific assumptions of each scenario.

A.3.1 Business as Usual

In the PY23-24 LOLE study, weather-dependent outages[13] for coal and gas resources were first included in the LOLE study model. Historical MISO GADS[14] data from 2017-2021 was gathered and analyzed to develop forced outages and hourly temperatures by LRZ. From the analysis, which showed a strong relationship between cold temperatures and forced GADS outages for many LRZs, hourly outages in MW were developed for each LRZ and included in the PY23-24 LOLE study model as negative perfect generation.

This analysis implemented the PY23-24 LOLE study outages as hourly MW "adders," with one fixed shape for each weather year. Figure A-9 presents two samples of the MISO-wide weather-dependent outages for the PY23-24 model.

[13] Astrapé Consulting, *MISO Seasonal Inputs for the 2022 LOLE Study*, July 2022.

[14] NERC, Generating Availability Data System

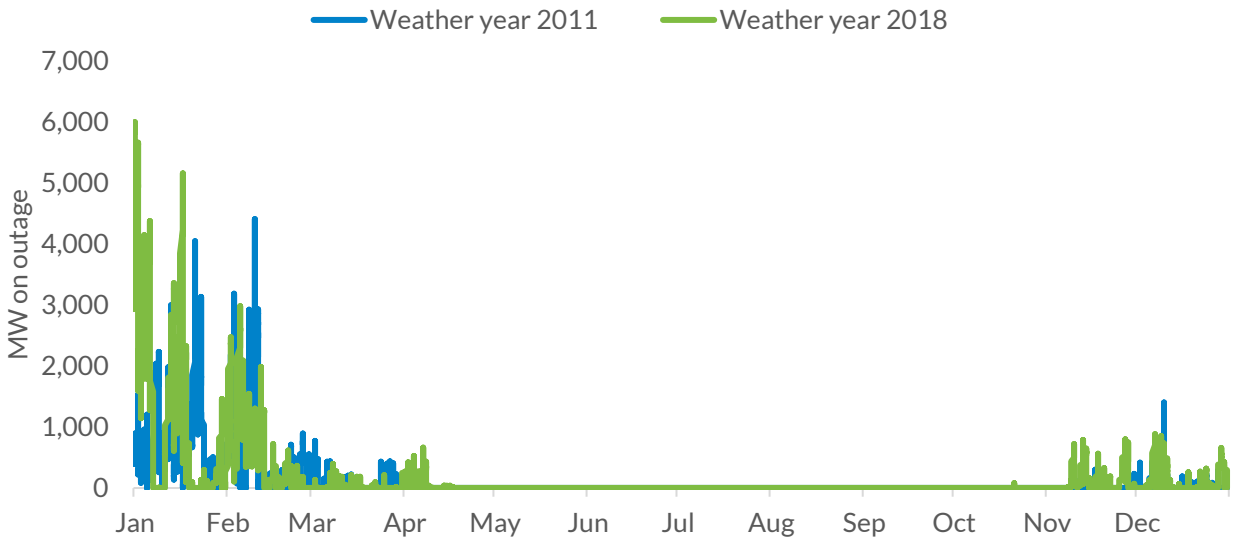


Figure A-9: Sample MISO-wide modeled, weather-dependent outage profiles for study year PY23-24

For the 2027 and 2032 models the hourly outages were scaled based on ICAP in PY23-24 compared to 2027 and 2032. The study represented the Flex units as gas units, so the gas ICAP increased by 65% for 2027 and 70% for 2032, compared to PY23-24. Coal ICAP decreased by 51% for 2027 and 74% for 2032. In all, the hourly outages increased by 35% for 2027 and 32% for 2032, compared to PY23-24.

A.3.2 Enhanced Risk Assessment (ERA)

MISO included the regional directional transfer constraint between MISO North/Central and MISO South in the ERA cases. This constraint places a transfer limit of 3,000 MW from North/Central to South and 2,500 MW from South to North/Central, as shown in Figure A-10. There is no other transmission modeled between individual LRZs.

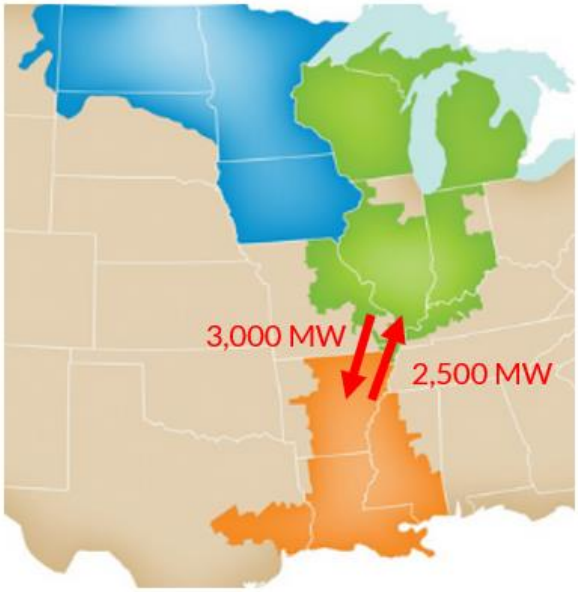


Figure A-10: MISO sub-regions with the regional directional transfer (RDT) constraint highlighted.

Adding transmission constraints complicates the LOLE adjustment process, which is straightforward in traditional copper sheet resource adequacy models. There are multiple ways to reach LOLE targets, depending on 1) whether the LOLE target is enforced at the system level or for each region individually and 2) how adjustments are distributed across the regions. Balance of risk between regions shown in the results section is highly dependent on the selected adjustment method and LOLE target area. Changing the methodology used to adjust may have an impact on simulation results, however, the direction of the results (e.g., shift in risk) are expected to be unchanged.

For the ERA scenario, fixed load adjustment for LOLE analysis was added to each region based on their contribution to MISO coincident peak load. Each region was not adjusted to an independent LOLE target. Instead, all of MISO was adjusted to the 0.1 days/year target, which resulted in a risk profile that was not evenly distributed between the two regions (North/Central and South).

A.3.3 Adequacy-Flexibility Constraint

The goal of this scenario was to further test the BAU model's ability to respond to ramping constraints within the resource adequacy simulations. Both the BAU (without flexibility constraints) and adequacy-flexibility models (with the constraints) were run as rounded relaxation problems for equivalent comparisons.

The historical five year's economic minimum and maximum dispatch and maximum ramping up and down data of thermal units was collected from MISO's historic operation data archive. When commercial pricing node match was available between the unit in operation and the existing unit modeled in PLEXOS, the five-year average of each property was used directly. For the future units and units with missing mapping, a class average was used. To calculate the class average, a class was first defined based on the fuel type of the unit. Among each fuel type, individual units were classified between large, medium, and small categories to form three aggregation groups. PLEXOS units with missing economic mappings were separated into the same classes, first by fuel type and then by their maximum capacity and were assigned the corresponding class average values. Wind and solar curtailment were not considered during the simulation, posing some limitations to the system's capacity to react to net load ramping.

A.4 Results

This subsection summarizes the findings of the analysis. The three scenarios presented in the last subsection were run across study years.

A.4.1 Business as Usual

As expected, LOLE for the PY23-24 model was only present in the summer season with the annual adjustment, and fixed load was added to the remaining seasons to reach a LOLE of 0.01 days/year.

For the 2027 model, LOLE was present in both summer and fall with the annual adjustment, and for the 2032 model, LOLE was present in both summer and winter, which suggests seasonal shifts in risk as the resource portfolio evolves. Figure A-11 presents the loss of load results for the BAU case, showing seasonal loss of load hour frequency from the models, as well as expected unserved energy (EUE) and LOLE for each model. The results show the highest risk in summer for PY23-24, summer and fall for 2027, and summer and winter for 2032.

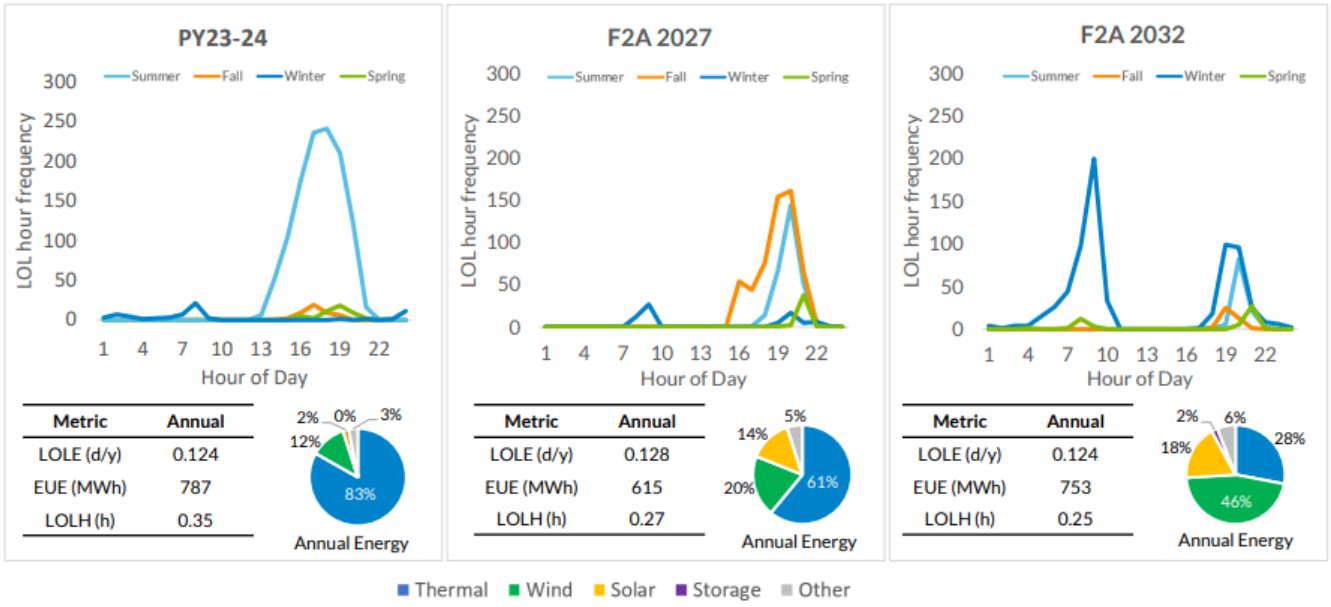


Figure A-11: Loss of load results for the business-as-usual case

DLOL class accreditation estimates were also found for each model year. Due to processing limitations, DLOL results were calculated for wind, solar, storage, and "all other" resource types, which includes all thermal resources and hydro and pumped storage.[15]

Figure A-12 through Figure A-15 present the DLOL results for the summer season, as well as seasonal average diurnal charts which indicate the hours of the season with EUE and average load, load net wind and solar generation, and average wind and solar generation across the season.

Generally, as solar increases in the resource portfolio, risk shifts into evening and early morning hours. At those times solar generation is low, which reduces the solar DLOL across model year portfolios. The charts also show an increase in the "duck curve" shape of net load, as solar increases in the portfolios. Changes to wind DLOLs across model years are mixed as risk shifts into or away from weather years with lower-than-average generation and is less dependent on the time of day of the risk than is solar. Storage DLOLs result in lower values for spring and winter for 2032, as longer-duration EUE events occur which limit the assumed 4-hour ability to fully charge and discharge across the duration of events.

System Adequacy Insight #1:

Accreditation is aligned with the risk distribution, regardless of the underlying sources of risk modeled, and tracks the contribution of individual resources.

[15] All other resource types include nuclear, steam turbine coal, combined cycle, combustion turbine gas, steam turbine gas, flex units, hydro and pumped storage, demand response and interruptible load, solar / storage hybrid, and other.

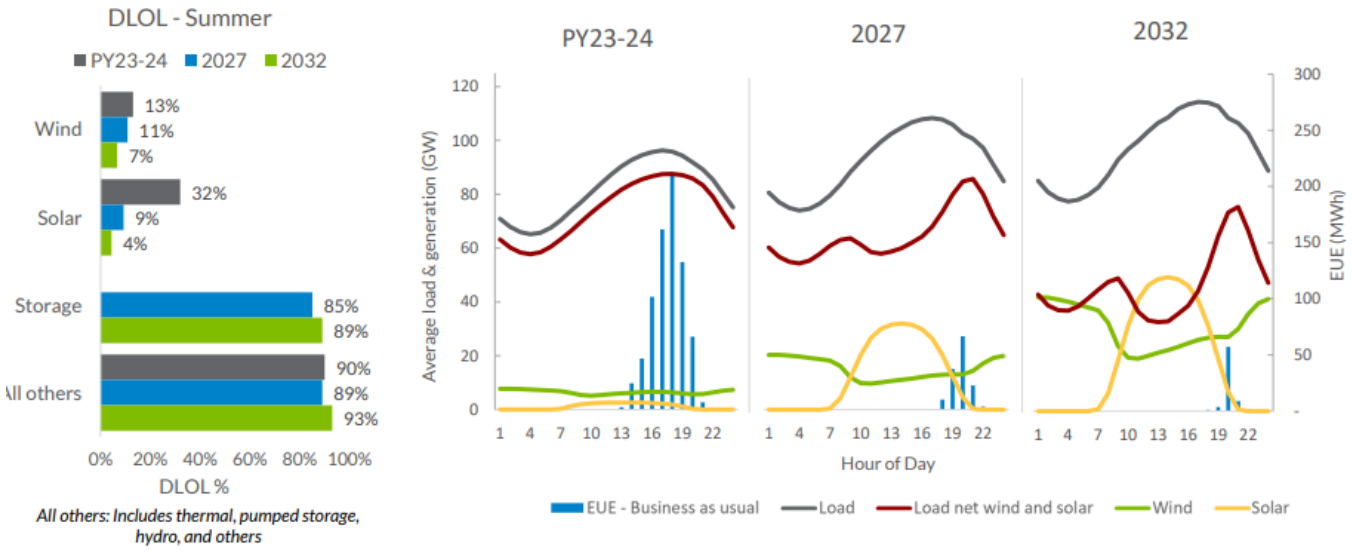


Figure A-12: Summer DLOL results for BAU case

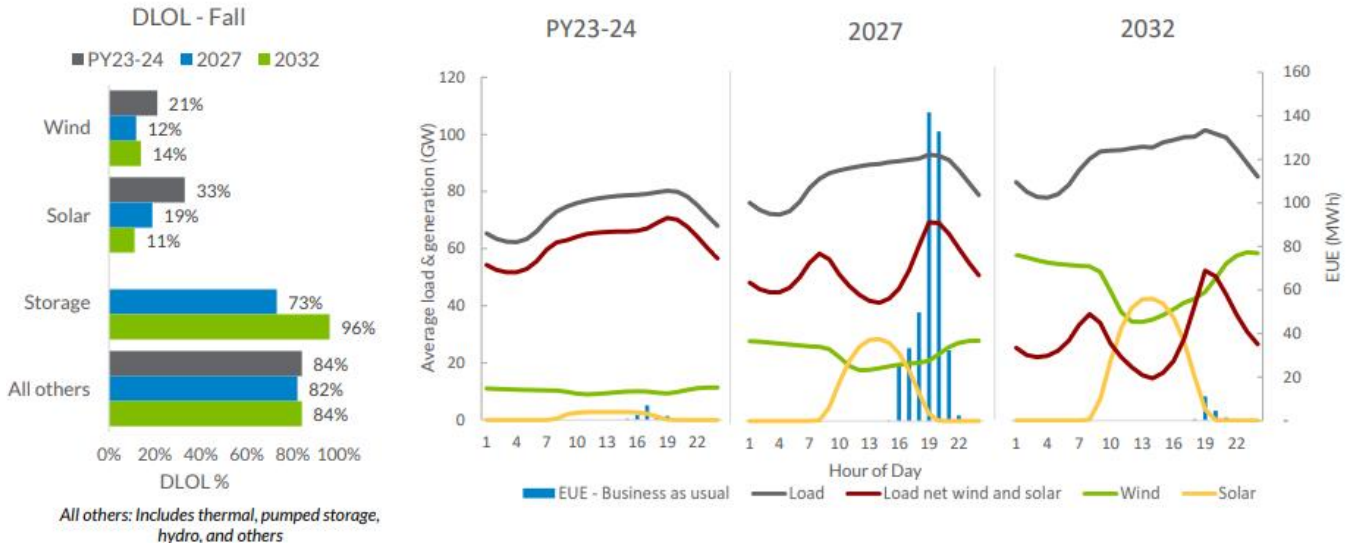


Figure A-13: Fall DLOL results for BAU case

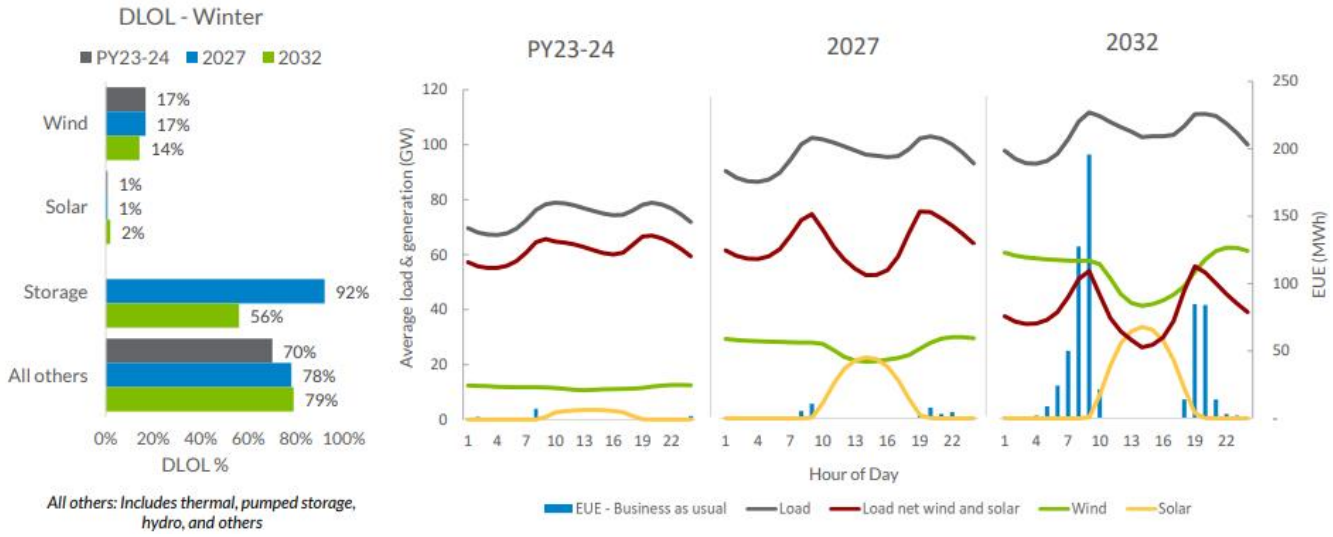


Figure A-14: Winter DLOL results for BAU case

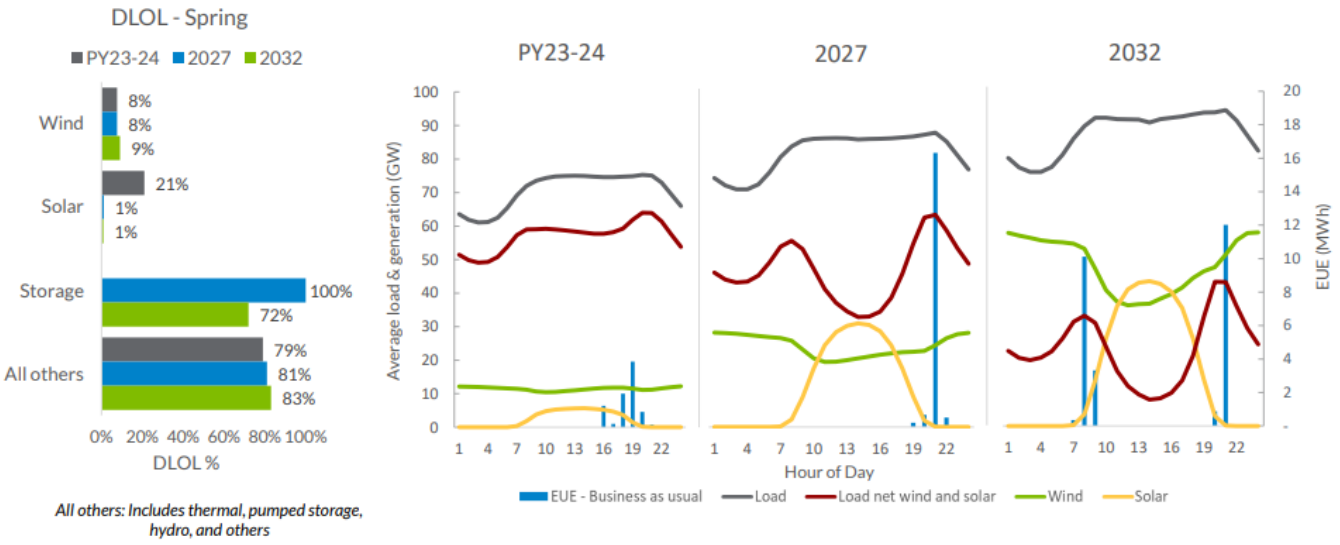


Figure A-15: Spring DLOL results for BAU case

A.4.2 Enhanced Risk Assessment (ERA)

The same adjustments that drove the BAU cases to criteria (0.1 days/year annual LOLE and at least 0.01 days/year LOLE per season) were applied to the ERA cases. The ERA cases, which incorporated the regional directional transfer limits between MISO North/Central and South, had a higher LOLE than the BAU case when at the same adjustment. As shown in Figure A-16, in 2027 LOLE experienced its largest increase in spring and winter when the regional directional

System Adequacy Insight #2:

The acknowledgment of weather-dependent outages and deliverability captures additional risk factors that are projected to appear in future portfolios.

transfer constraint was added, indicating those seasons had the most deliverability limitations between the two MISO regions. Similarly, in 2032 the LOLE increase was concentrated in the winter months for the ERA case, with minimal impacts during the rest of the year coming from the inclusion of the regional directional transfer constraint. The 2032 winter risk increase for the ERA case is driven mainly by deliverability constraints during the 2021 weather year (during Winter Storm Uri).

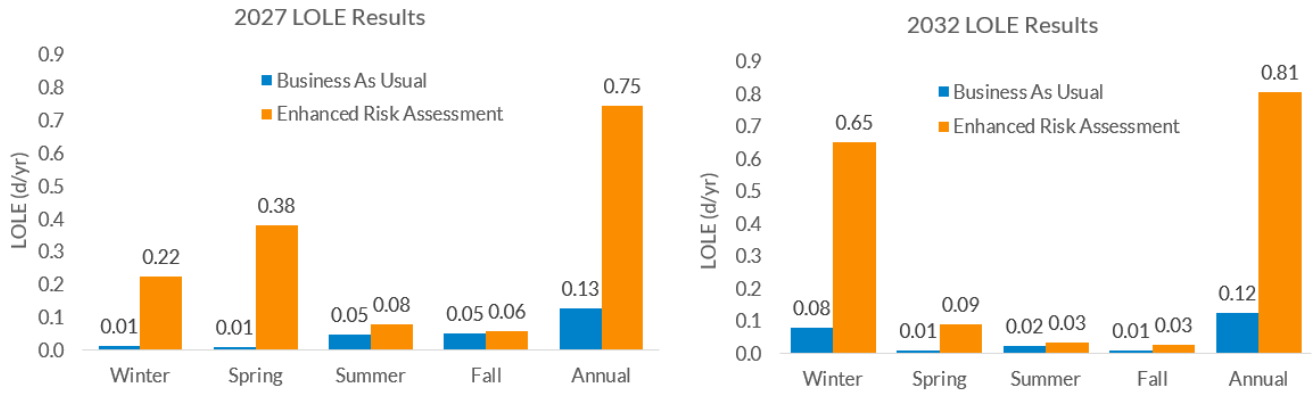


Figure A-16: LOLE comparison between the BAU And ERA cases at the same adjustment

The ERA cases were then adjusted to match the seasonal LOLE values of the BAU cases, to compare the resulting risk profiles and metrics before and after transmission is added in resource adequacy analysis. Figure A-17 shows that in both 2027 and 2032, the ERA case had a smaller EUE value than the BAU case when both were adjusted to the same LOLE target of 0.1 days/year. Loss of load hours (LOLH) did not present a clear trend; LOLH decreased for the ERA case in 2027, but it remained nearly the same between the BAU and ERA case in 2032.

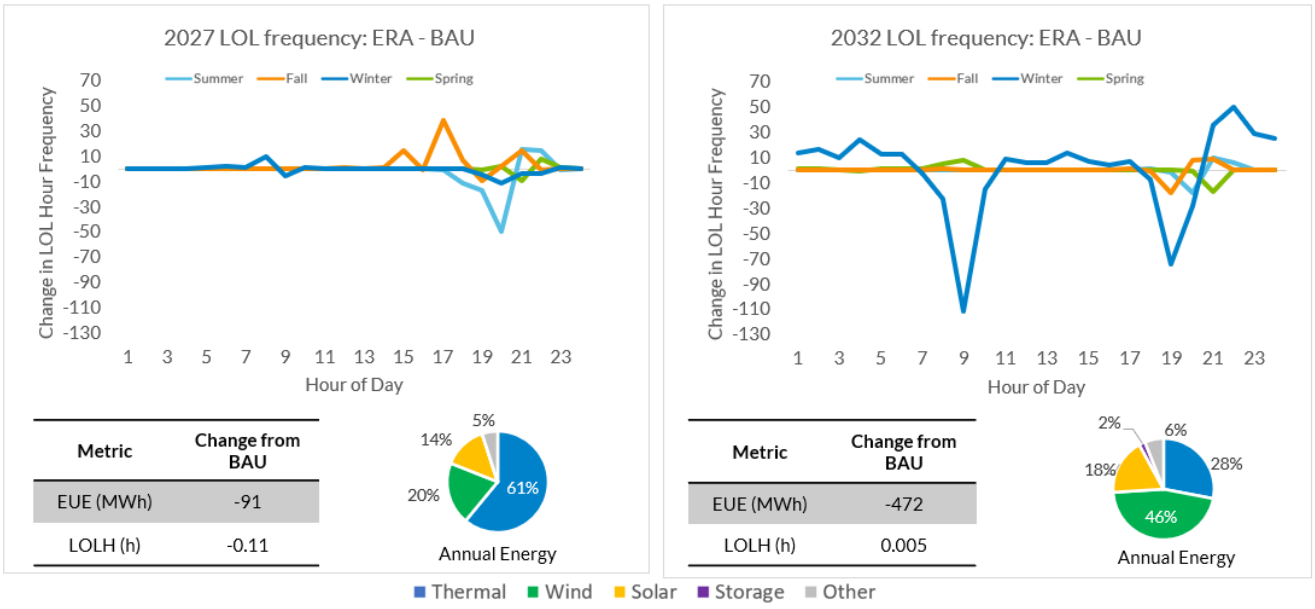


Figure A-17: Loss of load hour frequency and metric changes from the BAU to ERA cases when both are adjusted to the same LOLE targets

The reason for the difference in EUE between the two cases when they are both adjusted to a LOLE target of 0.1 days/year can be explained in part by Figure A-18. For both 2027 and 2032, the BAU cases have a higher average amount of unserved energy per loss of load hour compared to the ERA cases. Additionally, Figure A-19 the ERA cases have a much higher number of unique hours with loss of load across all weather years, despite having a similar LOLH. This indicates that events are smaller in magnitude in the ERA cases and are spread out over a larger portion of the year, rather than a few hours with severe conditions.

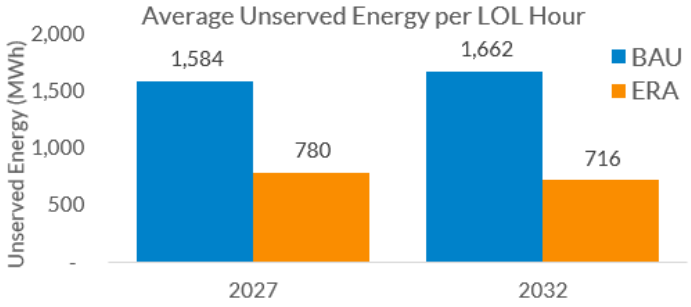


Figure A-18: Average unserved energy per loss of load hour for BAU and ERA cases when both are adjusted to the same LOLE targets

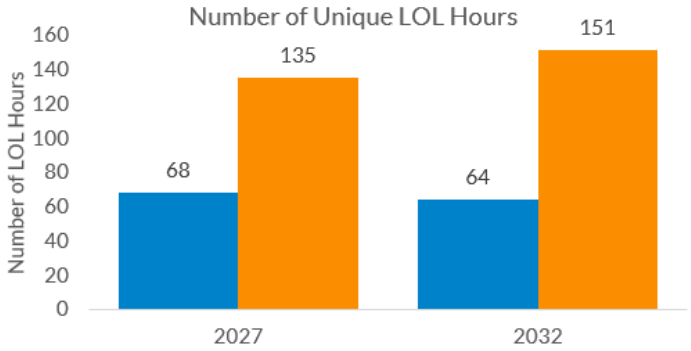


Figure A-19: Number of unique hours across weather years with loss of load when BAU and ERA cases are adjusted to the same LOLE targets

Figure A-20 and Figure A-21 show the accreditation change for each resource class when transmission constraints are added to the model. Wind DLOL increased in almost every season in both 2027 and 2032 from the BAU to the ERA case. This is because most of the wind capacity in the early years of the Future 2A model in the North/Central region, and wind was high in the North during loss of load events in the South in the ERA cases. The details of renewable and storage resource capacity by region for both 2027 and 2032 is shown in Table A-3.

Similarly, storage DLOL decreased in most seasons in the ERA cases because the majority of storage capacity is in the North/Central region and was charging during loss of load events in the South. An example of these two drivers of accreditation changes can be seen in Figure A-22, which isolates a portion of the 2021 weather year that corresponds with Winter Storm Uri — an event that drives a large portion of the LOLE for the 2032 model year.

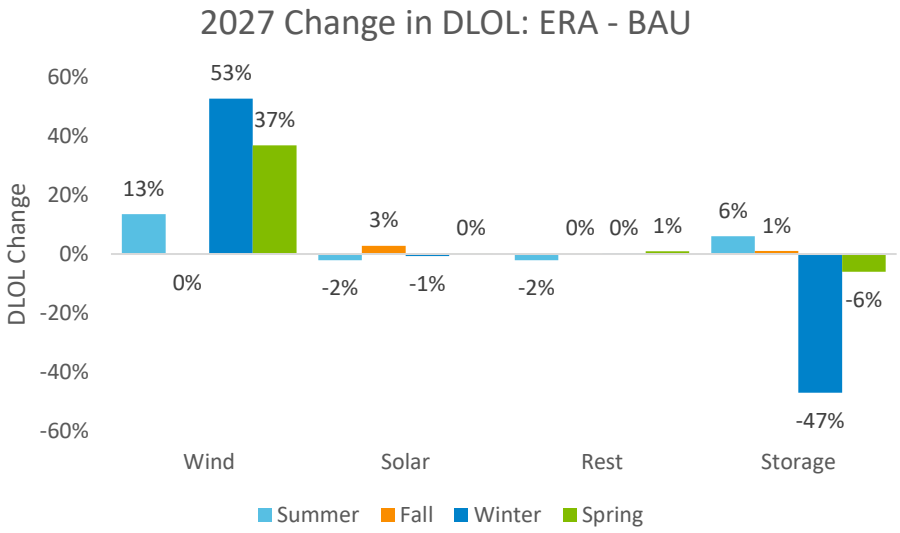


Figure A-20: Change in DLOL by resource class between the ERA and BAU cases in 2027 when both are adjusted to the same LOLE targets

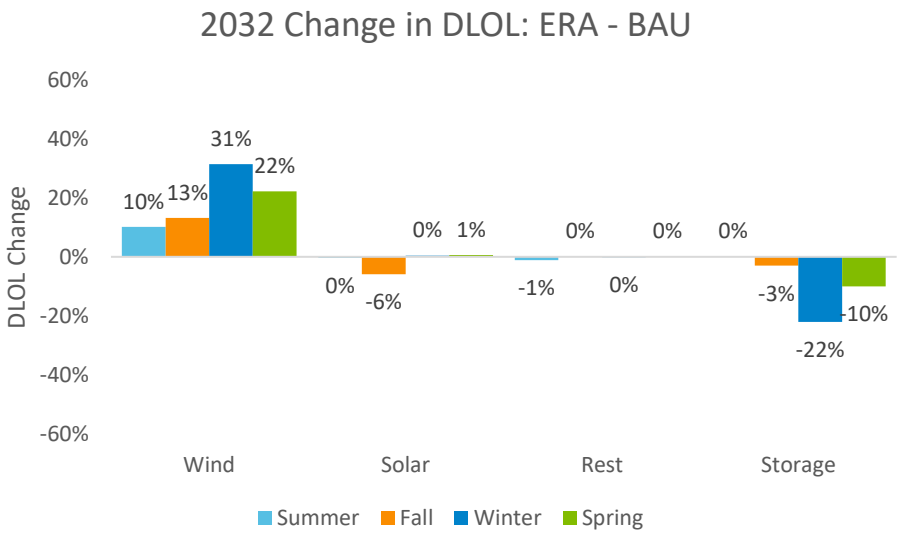


Figure A-21: Change in DLOL by resource class between the ERA and BAU cases in 2032 when both are adjusted to the same LOLE targets

Generator class	2027 ICAP (GW)		2032 ICAP (GW)	
	North/Central	South	North/Central	South
Wind	48.5	1.3	105.1	1.7
Storage	3.6	0.02	6.0	1.3
Solar	28.9	11.9	45.2	18.8

Table A-3. Renewable and storage installed capacities (ICAPs) by region from the Future 2A expansion

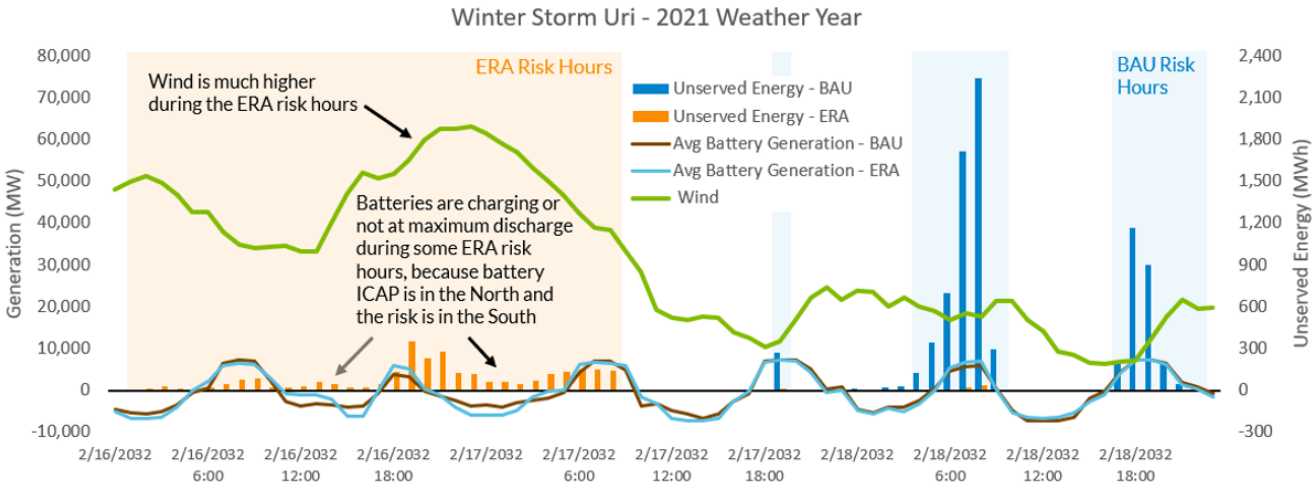


Figure A-22: Example of wind and battery generation and unserved energy from the BAU and ERA cases during Winter Storm Uri in the 2021 weather year simulation

A.4.3 Adequacy-Flexibility Analysis

The adequacy-Flexibility study model used the 2032 BAU model at criteria, i.e., after the LOLE adjustment was completed on a seasonal basis. No additional calibration of the LOLE was applied in this part of the analysis.

System Adequacy Insight #3:

Initial system adequacy-focused flexibility analysis points to potential issues in 2032, additionally analysis is required to understand the implications.

The analysis focused on finding the most challenging event the system might experience, by adding further constraints to the period in which the BAU model's adequacy was most tested. In each season, a week with the highest unserved energy amongst all weather years simulated in BAU was chosen as the starting point. Figure A-23 shows the weeks with high EUE present high correlation of net load and net-load ramping, making the period suitable for testing Adequacy-Flexibility constraints.

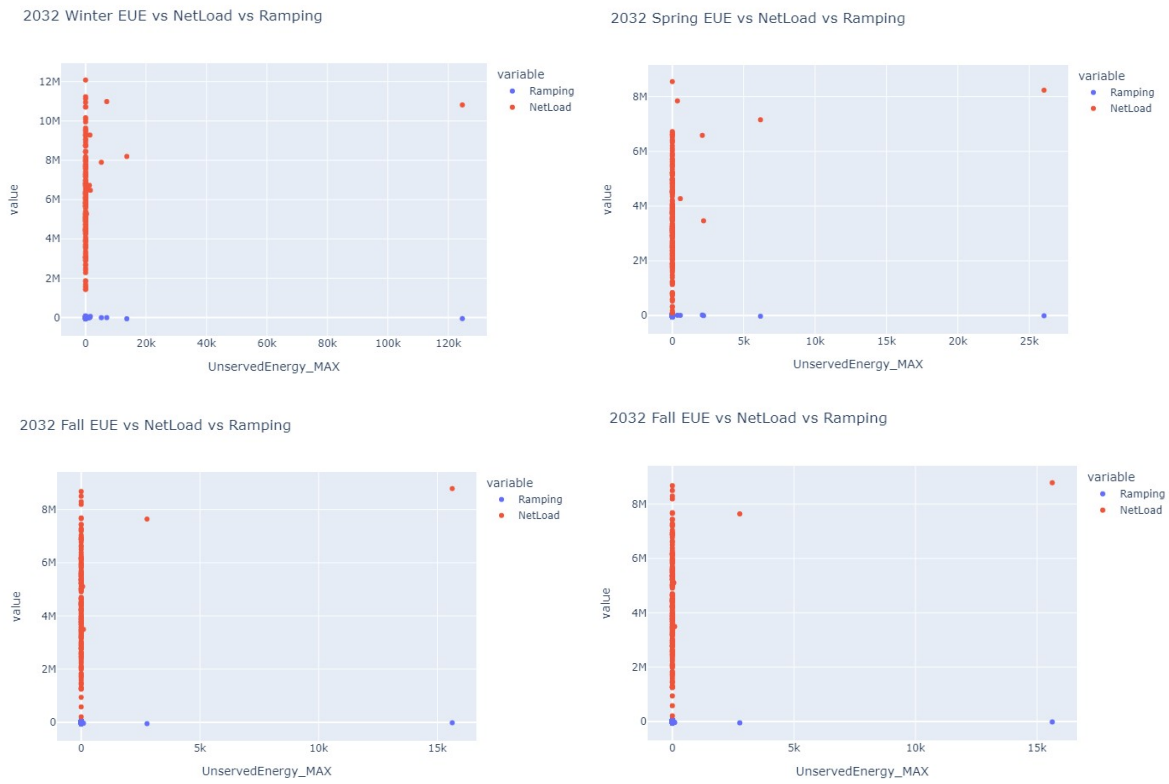


Figure A-23. Weekly unserved energy (MWh) vs net load (MW) and net load ramping (MW) of BAU

Table A-4 shows the final week and weather year chosen for the analysis. The corresponding week of event dates were simulated for the 2032 study year.

Season	Study Year	Weather Year	Week	Dates
Winter	2032	2021	8	February 22-28
Spring	2032	2019	10	March 4-10
Summer	2032	2010	33	August 16-22
Fall	2032	2012	37	September 10-16

Table A-4: Adequacy-Flexibility Analysis Seasonal Simulation Period

No significant changes were observed between the BAU and the Adequacy-Flexibility scenarios for LOLE (number of expected days with events) or LOLH (number of expected hours with events). The EUE of the system showed a significant increase in all seasons, especially in Spring, as shown by Figure A-24. As illustrated in the System adequacy section of the *Attributes Roadmap*, high planned maintenance of thermal units was scheduled during spring and limited the availability of units with higher ramping capability.

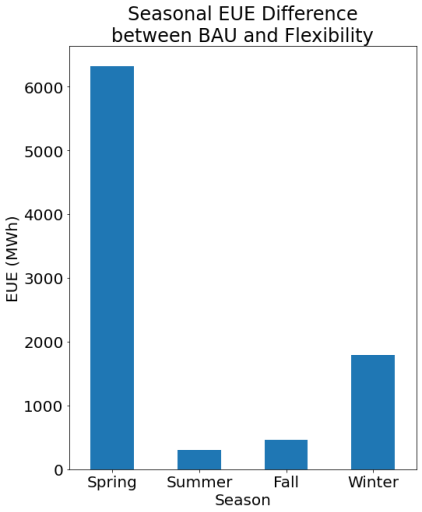


Figure A-24. Seasonal EUE Difference – BAU vs Adequacy-Flexibility

Winter showed the second highest increase in EUE between BAU and Adequacy-Flexibility scenarios. The weather year simulated, 2021, exhibited below average wind generation during its winter, causing longer duration of EUE event. Figure A-25 shows the seasonal comparison of EUE event duration between BAU and Adequacy-Flexibility. Both spring and winter show an increase in longer duration events when the flexibility constraints are applied to the resource adequacy model.

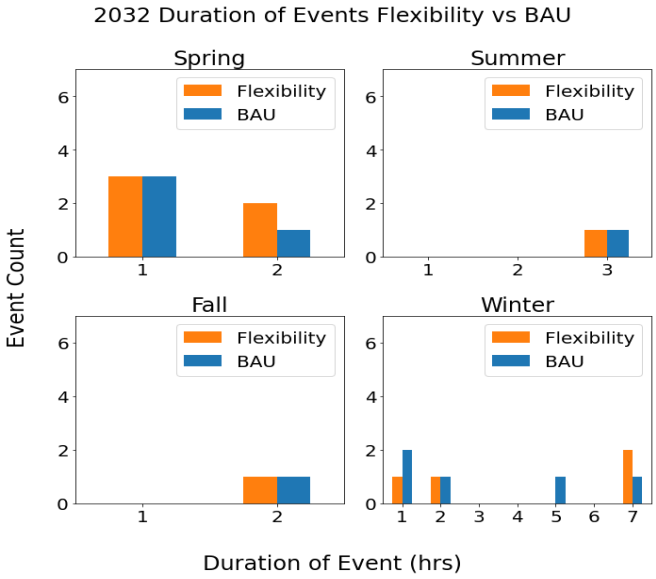


Figure A-25. Seasonal EUE Event Duration – BAU vs Flexibility

Future work may include enable wind/solar curtailment, five-minute simulation, and including operating reserves requirements.

A.5 Conclusions

This section described approaches, tools, and assumptions used in the system adequacy attributes analysis that informed insights and roadmap development. The work of modeling enhancements and understanding their impact on reliability and accreditation will be ongoing. Future investigations into planning horizon attribute risks and solutions could target questions such as:

- How can the LOLE modeling process be enhanced by including additional risk factors in the planned maintenance scheduling?
- What level of transmission granularity is needed to acknowledge local risk factors?
- How should storage operations be captured in LOLE models?

B.Operational Adequacy

The aim of the operational adequacy analysis was to evaluate MISO's current energy and ancillary services market products and rules, to ascertain whether they are able to procure adequate system reliability attributes, in particular under stressed system conditions. The approach taken was to run a two-stage simulation replicating a simplified version of MISO's two-settlement market, comprising of day-ahead market unit commitment followed by real-time market economic dispatch. This approach was used to analyze both the current portfolio and the future portfolio using MISO's Future 2A scenario. This analysis supports the insights and solution hypothesis presented in MISO's 2023 *Attributes Roadmap*.

B.1 Framework for Market Simulations

B.1.1 Tool

The energy market simulation portion of the system reliability attributes analysis work was carried out using a MISO-enhanced version of the Electrical Grid Research and Engineering Tool (MISO EGRET) that has implemented many of MISO's products, services, and commitment rules. The original EGRET is a Python-based unit commitment and economic dispatch tool that was developed by the Sandia National Lab. MISO EGRET is based on the original EGRET, and was developed jointly with Sandia National Lab, National Renewable Energy Laboratory (NREL), Nexant and Arizona State University under an ARPA-E funded project. For this analysis, MISO developed and tested a new two-stage (day ahead and real time) modeling framework suitable for the system reliability attributes analysis work.

B.1.2 Metric

For this analysis, it was assumed that in the operating timeframe unserved energy is more likely to occur on extreme days than days with normal system operating conditions. Hence the current and future portfolio simulations focused on specific individual days, rather than the whole year. Because only individual days were simulated, this report includes the amount of unserved energy for those days instead of expected unserved energy, which is typically used to assess a longer period such as a season or a year.

For the analysis of the current portfolio, four extreme days were selected from the recent history, one from each season. This provided a good representation across the year and captured seasonal variations. For the future portfolio only winter and summer days were selected because they had the highest potential risks, based on the screening methodology used in this study.

B.1.3 Two-Stage Simulation Framework

It is important to note that the simulation approach was not intended to replay the historical emergency events exactly as they occurred. During those historical events, MISO Operations (acting in coordination with MISO's neighbors) took multiple actions to manage the actual events successfully. Thus, the simulated scenarios will differ from the historical outcomes. This was an intentional modeling choice given that the purpose of these simulations was to analyze "what-if" scenarios and thus to learn key lessons for the System Attributes initiative.

The two-stage simulation framework is presented in Figure B-1 and is organized as follows:

- **Day-ahead stage**: generation unit data such as unit parameters and offers were taken from day-ahead production cases. For renewable units (wind and solar) their economic maximum values were taken from the data of the Forward Reliability Assessment Commitment (FRAC) process. MISO's FRAC load forecast was used rather than market participant demand bids, as is typically the case in the Day-Ahead

Market (DAM), since the aim was to judge the impact of MISO's forecast. The FRAC Net Scheduled Interchange amount was considered (i.e., the net imports from MISO's neighbors). Virtual transactions were excluded.

- **Real-time stage**: data from MISO's look-ahead commitment (LAC) process was used for simplicity. The 96 LAC production cases for the day were combined by taking the first interval from each of them and stitching them together.[16] The small differences between the first interval of LAC and the real-time market cases (such as in outages or forecasts) were ignored. The real-time load was assumed to be known in advance with perfect foresight for the economic dispatch simulation.

The simulations for both current and future portfolios did not consider transmission constraints other than the regional directional transfer limit.[17] This limit is 3,000 MW for transfers from North to South, and 2,500 MW for South to North.

This analysis focused solely on the energy and ancillary services market constructs. Intra-day commitments and other reliability actions usually taken by MISO operators were excluded from this framework.

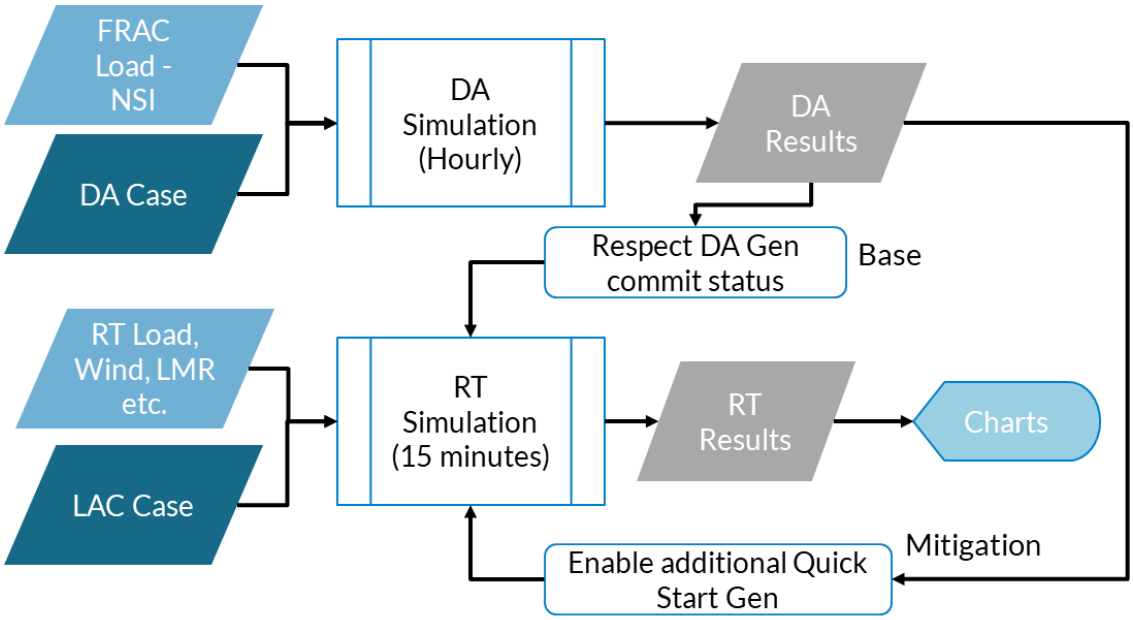


Figure B-1: Simulation framework for energy and ancillary services market

[16] LAC executes every 15 minutes throughout the day on a rolling basis, and the first interval of LAC has a 15-minute span. Thus, we get 96 LAC cases for the whole day.

[17] MISO's Settlement Agreement with SPP and the Joint Parties provides that the upper limit of SPP and the Joint Parties' Available System Capacity is 3,000 MW for flows from MISO North to MISO South and 2,500 MW for flows from MISO South to MISO North. These limits are referred to as Regional Directional Transfer (RDT) Limits.

B.1.4 Screening Methodology for Stressed Periods

The stressed period analysis aimed to find days in the future which have the highest potential for challenging operating conditions. The analysis was based on system net load[18], and associated variability and forecast uncertainty.

The screening analysis assumed that potential flexibility needs are likely to be highest during days with high amounts of net load, net load variability and forecast uncertainty. Net load is defined as load minus renewables (wind and solar PV). Variability is defined as net load changes between time intervals. Forecast uncertainty is defined as the difference between real-time net load and day-ahead forecasted net load.

For each season and future year, the potential stressed days are identified as follows:

- Find the days that contain three or more hours which are at or above the 95th percentile of system-wide net load
- Find the days that contain at least one hour at or above the 95th percentile of net load variability (net load ramp in GW/hour)
- Find the days that contain at least one hour at or above the 95th percentile of net load uncertainty between day-ahead to real-time (net load forecast error in GW)
- Find days in common that have been flagged in Steps 1, 2 and 3 and identify them as stressed days in each season
- The above steps were repeated for each future year, 2027 and 2032
- The days in each future year and season with the highest net load, net load variability and net load uncertainty were identified as the target days for the simulations

B.2 Scenarios

Different types of scenarios were developed to inform the solution hypothesis being considered:

- **Base Case**: this simulated a day-ahead unit commitment for a selected day followed by a real-time economic dispatch. The assumptions described above in the two-stage simulation framework section were used for this scenario. The commitment status for generator units selected in the day-ahead commitment were respected when executing the real-time stage.
- **Stressed Scenarios**: additional stressors were applied assuming the loss of resources that were important for managing the challenging days. This allowed checking whether the day-ahead commitment would have been sufficient to avoid unserved energy. For example, it was assumed that resources such as load-modifying resources or imports etc. were lower than on the given historical day.
- Mitigation Cases:
    - *Mitigation using Quick Start units*: any offline quick start units that were not already committed by the day-ahead process were available to be deployed, assuming perfect foresight
    - *Mitigation using load-modifying resources*: additional load-modifying resources were available to be deployed to mitigate the potential unserved energy, again assuming perfect foresight

[18] Net load is defined as gross minus wind and solar for this analysis.

B.3 Future Portfolio Assumptions

The analysis of the current portfolio used input data from MISO historical records. This section describes the data inputs, assumptions, and methodology for analysis of the future portfolio. The aim of the future portfolio analysis was to evaluate whether MISO's current market products and requirements are sufficient to meet the needs as the generation fleet evolves in the future, and to identify any gaps in the system reliability attributes.

Day-ahead "forecast" load profiles were generated from the real-time "actual" load profiles for future years 2027 and 2032. For wind and solar day-ahead "forecasts" were also generated from the real-time "actual" renewable production for those future years. For both the day-ahead and real-time stages, the net load was obtained by subtracting renewable production from the load and this net load data was used to analyze the potentially stressed periods. Finally, market simulations were conducted for those stressed periods using the MISO EGRET simulation tool developed by MISO.

B.3.1 Data Inputs and Assumptions

For historical time periods both actual and forecast data for load and renewables were available. However, for future years for load only "actual" projections were available, while for renewables "actual" and "forecasts" at the 6 hours ahead (6 HA) timeframe were available. Day-ahead "forecasts" were also needed for the market simulations.

Table B-1 summarizes the sources for the key data inputs needed for the market simulations of the future portfolio, as follows:

- Load: Data from MISO Future 2A was used for projections of future real-time "actual" load. The details of this dataset are described in the Planning Adequacy section (A.3.3).
- Wind and solar: For wind and solar units their locations were determined based on the siting work done under MISO Futures. Next, "actual" real-time and "6 HA forecasts" for renewable unit profiles were generated for these locations using the data supplied by Vibrant Clean Energy.

2027/2032 Input Data	Load	Wind	Solar
Actual	From MISO F2A	From Vibrant Clean Energy	From Vibrant Clean Energy
6 HA Forecast	MISO generated	From Vibrant Clean Energy	From Vibrant Clean Energy
Day-Ahead Forecast	MISO generated	MISO generated	MISO generated

Table B-1: Sources for input datasets needed for market simulation of the future portfolio

The assumptions for the load, renewables, and non-renewable generator units for the future portfolio are summarized in Table B-2.

Consideration	Assumption
Future real-time "Actual" Load	MISO Future 2A load data using the weather year 2018 was considered. The data which includes electrification was aggregated from local balancing authorities (LBAs) to system-level to create annual load profiles at hourly granularity for 2027 and 2032. For the sub-hourly analysis, the hourly profiles were linearly interpolated to generate five-minute granularity load profiles.
Renewable energy production	Offered prices for wind and solar units were assumed to be zero. Wind and solar units were modeled as dispatchable intermittent resources and their hourly generation MW profiles were based on projections made for the future years 2027 and 2032. Wind and solar hourly profiles, based on siting of individual units were created for 2027 and 2032 "actual" generation, using the Vibrant Clean Energy dataset for the 2018 weather year. Also, the Vibrant Clean Energy dataset was used to obtain "forecast" profiles for the six hours ahead timeframe for these units. The hourly profiles were interpolated to generate the five-minute granularity renewable profiles. Finally, all the individual wind and solar profiles were aggregated to the regional and systemwide levels.
Non-renewable generator units	The future portfolio capacity used in the simulations was checked to ensure consistency at the LBA level with the Future 2A capacity for each fuel type. Characteristics (lead time, ramp rate, etc.) for non-renewable generation units were consistent with those from the current portfolio.
Generation outages	Planned and forced outages per season were based on historical average rates for the previous three years. The impact of planned and forced outages in future years 2027 and 2032 were accounted for by derating maximum limits of generation resources for each fuel type.
Net scheduled interchange	The historical real-time systemwide net scheduled interchange profile from a selected event day (Dec. 24, 2022, Winter Storm Elliot) was used for current and future portfolio simulations.
Battery storage operation	Current electric storage resources unit dispatch operation was scaled up consistent with capacities in each MISO region (North/Central, South) based on Future 2A capacities for the future years 2027 and 2032.

Table B-2: Key Assumptions for the Flexibility Assessment

B.3.2 Methodology for Forecast Uncertainty Assumptions

The methodology that MISO used to generate the datasets labelled as "MISO generated" in Table B-1 is as follows:

- The historical day-ahead and real-time load datasets were used to calculate the Total Error in the historical load forecast
- A back-cast dataset that excludes the impacts of weather forecast errors in the load forecast model was used to provide the Model Error
- Assuming that the forecast errors were additive, Weather Error was calculated as the difference between Total Error and Model Error
- The ratio of Weather Error to Total Error for day-ahead load forecast was calculated
- From the available historical actual and 6 HA forecast data, the historical 6 HA load Total Error was calculated

- Using the same ratio of Weather Error to Total Error from the day-ahead case, the 6 HA historical Weather Error and Model Error were obtained
- For future years, MISO assumed that relative Weather Error remains the same, while the Model Error is reduced by 50% (due to assumed improvements in forecasting techniques), i.e., Future 6 HA load Total Error % = Weather Error % + 50% * Model Error %
- This Total Error % is applied to the future actual load profile to get the 6 HA forecast for each of 8,760 hours
- For future day-ahead load forecast error, the steps were similar to those for the 6 HA load forecast case, as described above, i.e., Future day-ahead load Total Error % = Weather Error % + 50% * Model Error %

The historical load Model Error in day-ahead is greater than 6 HA. MISO maintained this relationship in the future data for consistency.

For future day-ahead wind and solar errors, MISO scaled the 6 HA errors using the ratios of the historical day-ahead error to the historical 6 HA error. For example, if in a particular hour of the year the historical 6 HA error is 3% and the historical day-ahead error is 4%, then a scaling factor of 4/3 = 1.333 is applied to scale the future 6 HA error in order to obtain the future day-ahead error. A similar calculation is applied for each of the 8,760 future hours in 2027 and 2032 to obtain the respective day-ahead forecast profiles for wind and solar.

B.4 Results

The increase in renewable (wind and solar PV) penetration in the future fleet results in new patterns in the diurnal net load profiles. The monthly average diurnal net load profiles for the years 2022, 2027, and 2032 are shown in Figure B-2, Figure B-3, and Figure B-4, respectively.

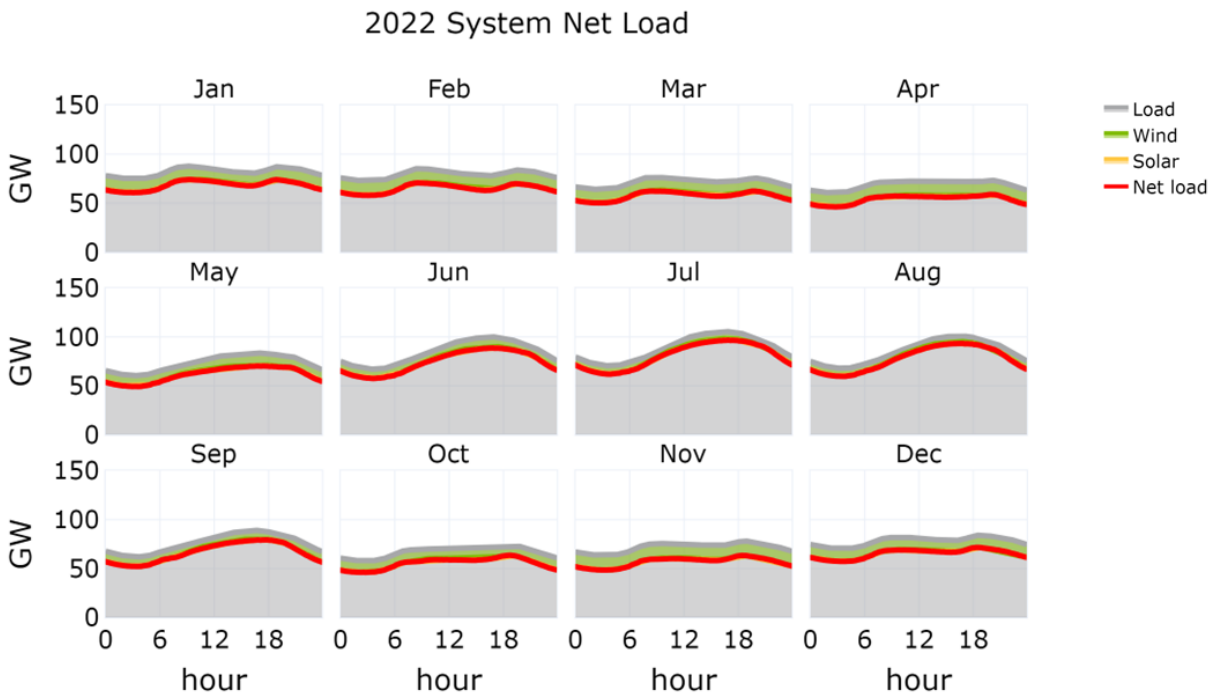


Figure B-2: Monthly averages of diurnal net load components for 2022

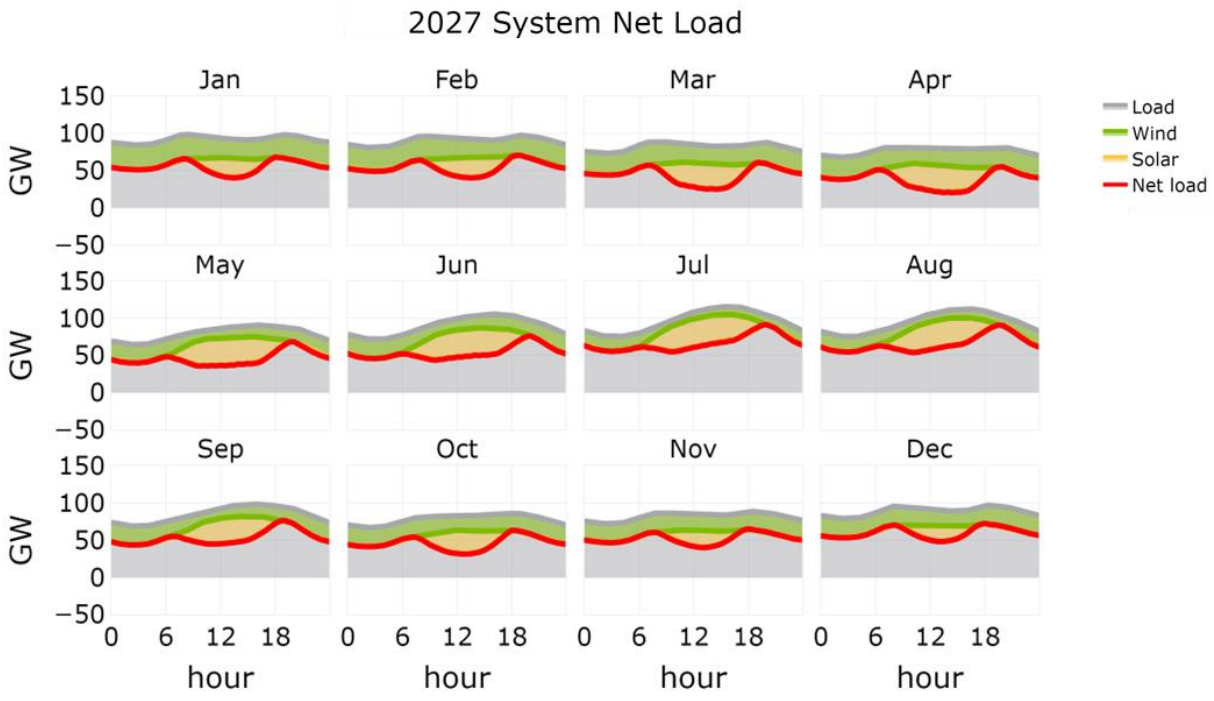


Figure B-3: Monthly averages of diurnal net load components for 2027

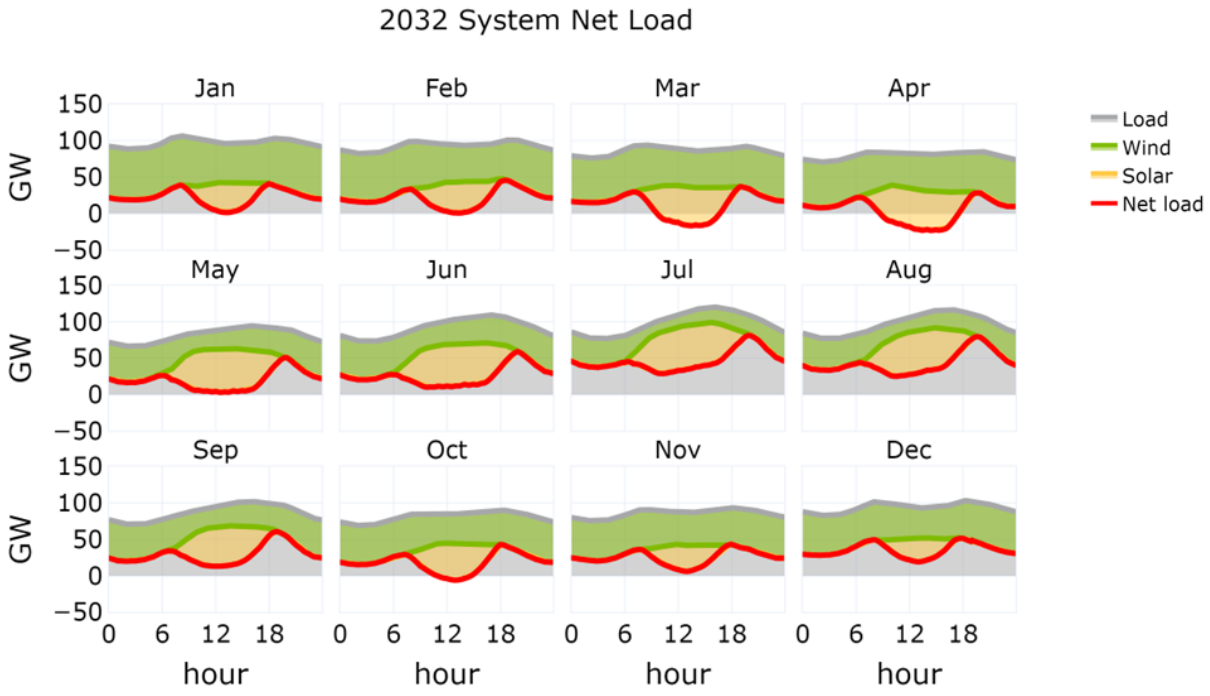


Figure B-4: Monthly averages of diurnal net load components for 2032

As these charts show, with increasing wind and solar penetration the duck-curve shape of net load appears between September and April in 2027 and becomes more pronounced in 2032. Assuming no curtailment of renewables, a number of hours in spring are shown to have negative net load in the afternoon.

Operational Adequacy Insight #1:

Given the fleet transition the increase in net load variability and uncertainty will require new/enhanced market products and dynamic requirements that can achieve the greater flexibility needs on the operational timeframe.

Driven by the portfolio evolution and load profile changes, the future net load ramping need is projected to be much higher. The net load ramp needs in both up and down directions (Figure B-5, Figure B-6) are expected to increase by 2027 and 2032. This poses a challenge as resources with fast ramping capabilities will be needed to manage the larger ramps.

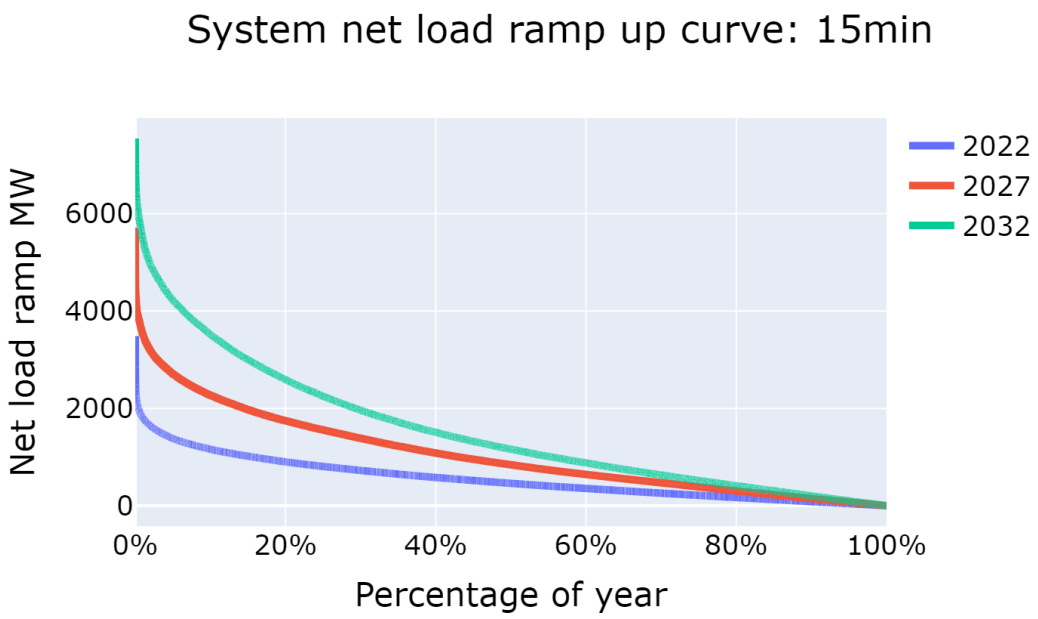


Figure B-5: Systemwide net-load ramp-up duration curve for 15 minutes

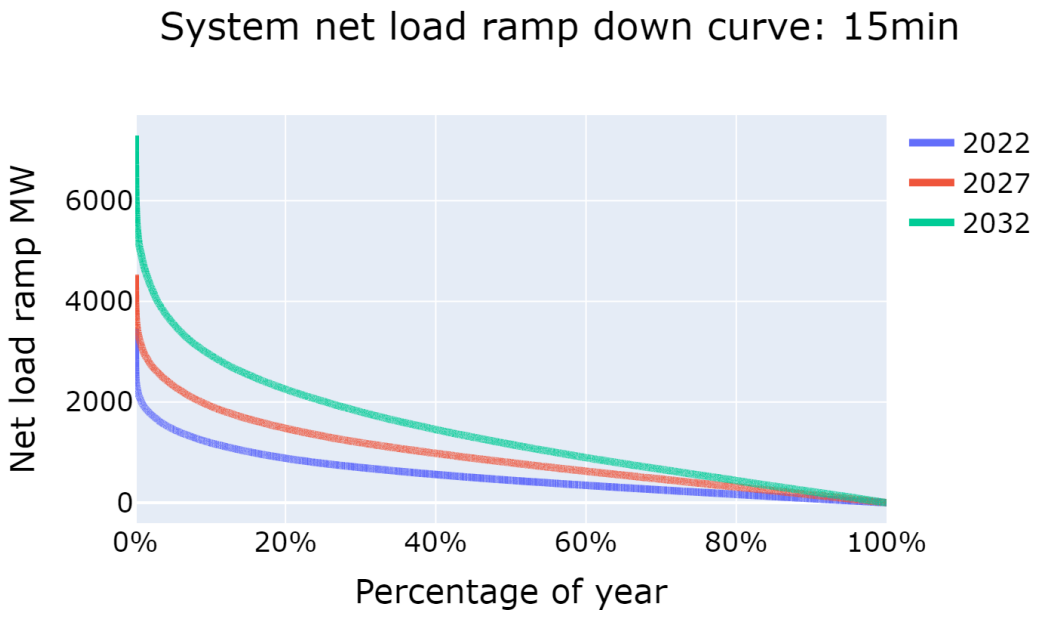
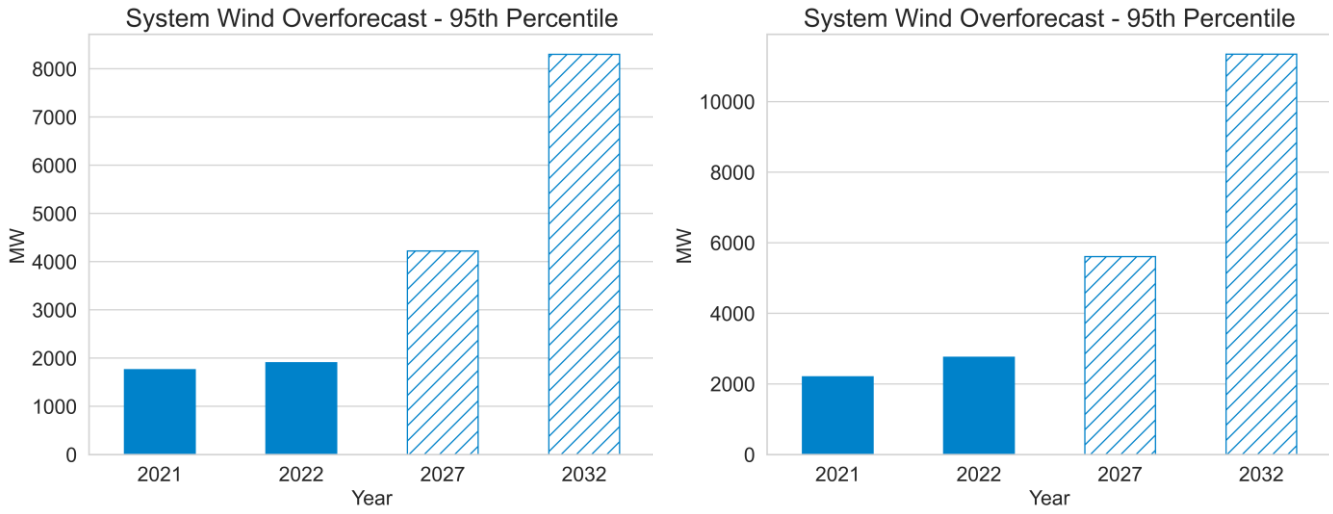


Figure B-6: Systemwide net-load ramp-down duration curve for 15 minutes

Forecast uncertainty for both wind and solar will increase in the day-ahead and short-term (6 HA) horizon from today to 2027 and 2032. For example, the 95th percentile of 6 HA wind over-forecast could increase from 1.9 GW in 2022 to 4.2 GW in 2027 and 8.3 GW in 2032 (Figure B-7a). While the 95th percentile of day-ahead wind over-forecast could increase from 2.8 GW in 2022 to 5.6 GW in 2027 and 11.3 GW in 2032 (Figure B-7b). These estimates assume an improvement in forecasting accuracy.



a) 95th percentile of six-hour ahead wind over-forecast b) 95th percentile of day-ahead wind over-forecast

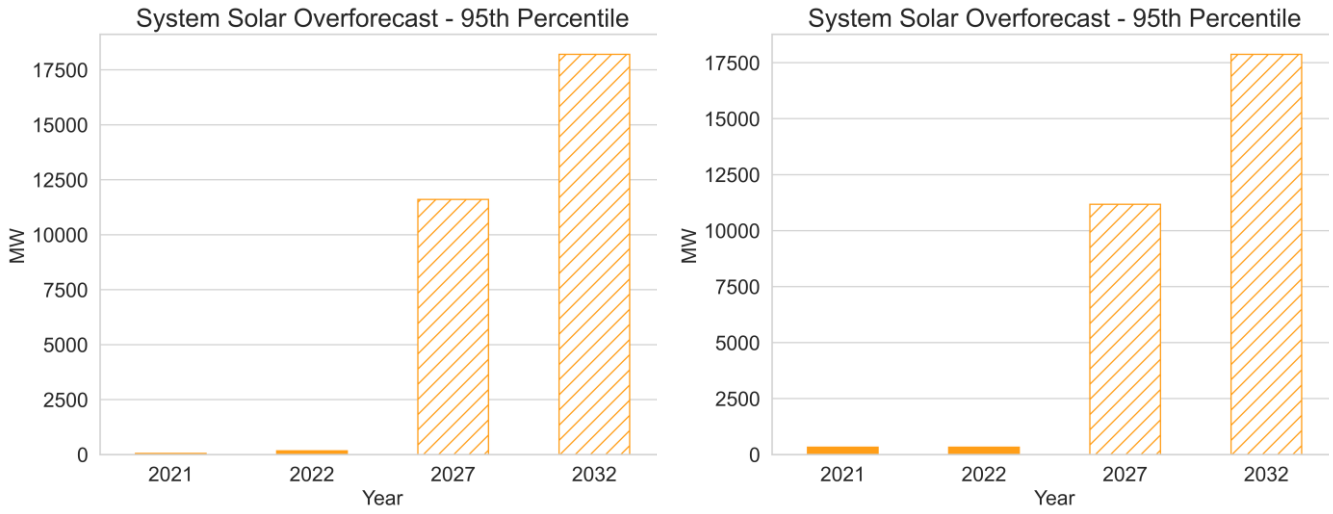
Figure B-7: Wind over-forecast errors in 2021, 2022, 2027 and 2032

Solar PV uncertainty could become larger than wind forecast uncertainty in the future, as solar penetration increases following the trends in Future 2A. The 95th percentile of six-hour-ahead solar over-forecast could increase from 0.17 GW in 2022 to 11.6 GW in 2027 and 18.2 GW in 2032 (Figure B-8a). The 95th percentile of day-ahead solar over-forecast could increase from 0.3 GW in 2022 to around 11.2 GW in 2027 and 17.9 GW in 2032 (Figure B-8b).

Literature on forecasting experience shows that shorter forecast lead times are correlated with lower forecast errors.[19] However, this was not the trend observed in MISO for 2021 and 2022, with the mean short-term solar forecast error being comparable or even larger than the day-ahead error. This analysis projected current MISO statistics for future years 2027 and 2032, so the trends did not match the expectation from literature. This could change in the future as the penetration of solar in the MISO footprint increases.[20]

[19] CAISO, "Day-ahead market enhancements discussion: Role of forecast uncertainty" Presented at CAISO's Market Surveillance Committee Meeting, Aug 27 2021.

[20] Penetration of solar PV in MISO footprint in 2021 and 2022 was much smaller than in California ISO (CAISO).



a) 95th percentile of six-hour ahead solar over-forecast b) 95th percentile of day-ahead solar over-forecast

Figure B-8: Solar over-forecast errors in 2021, 2022, 2027 and 2032

Figure B-9 shows the potential stressed days in 2027 and 2032 flagged by the screening method. Those days are highlighted as the cells in the calendar chart and are represented with their highest net load values (in GW).

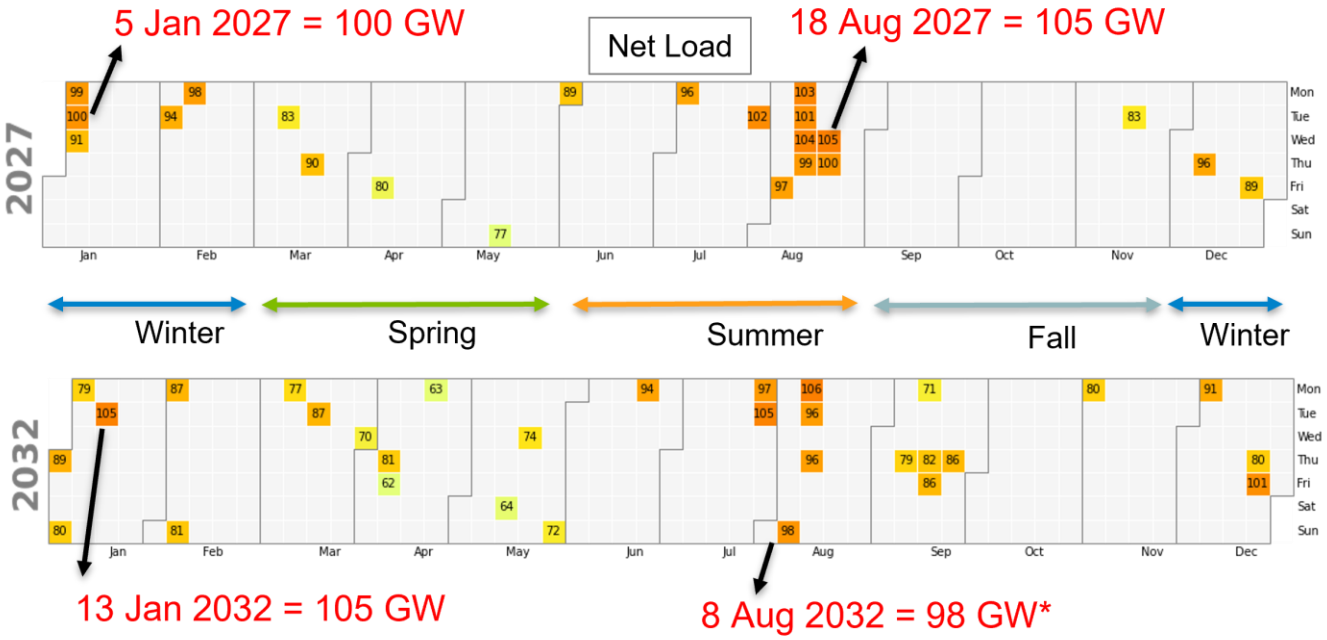


Figure B-9: Calendar chart of potential stressed days in 2027 and 2032

Figure B-10 presents a bar chart containing the actual maximum generation alert/warning/event days from 2022, as well as the potential stressed days from 2027 and 2032, grouped by the season. The operational risk in the future gets more spread out across the year as risky days begin to show up in the shoulder seasons. Additionally, the total number of risky days increases in the future.

Operational Adequacy Insight #2:

The projected increase in risky days and lack of guarantees for availability of emergency and external resources increase the need to rely on demand side resources.

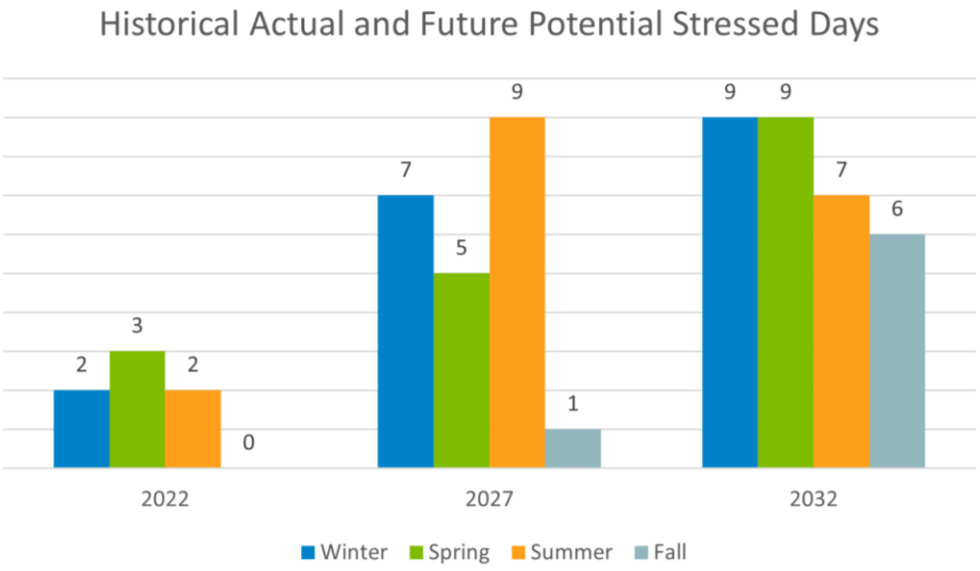


Figure B-10: Historical events and future potential stressed days by season

Figure B-11 shows the simulation results of various scenarios for the target potential stressed day for the event in winter of 2027. For the base case scenario (assuming no operator actions) the day-ahead commitment was inadequate to meet the real-time load, resulting in a small amount of unserved energy. Three individual stress scenarios are considered:

- A 50% drop in wind production throughout the day
- The removal of external imports (MISO rather ends up exporting power)
- A high-impact single gas pipeline outage

Operational Adequacy Insight #3:

The projected increase in duration and severity of events coupled with the retirement of conventional resources highlights the need for enabling the potential of emerging resources.

This last contingency, given Future 2A projected retirements, occurs in the MISO North/Central region and amounts to 6 GW. The wind-reduction scenario has the largest increase in unserved energy amongst the three cases. Finally, the worst-case event was simulated, where all three stress conditions occur on the same day.

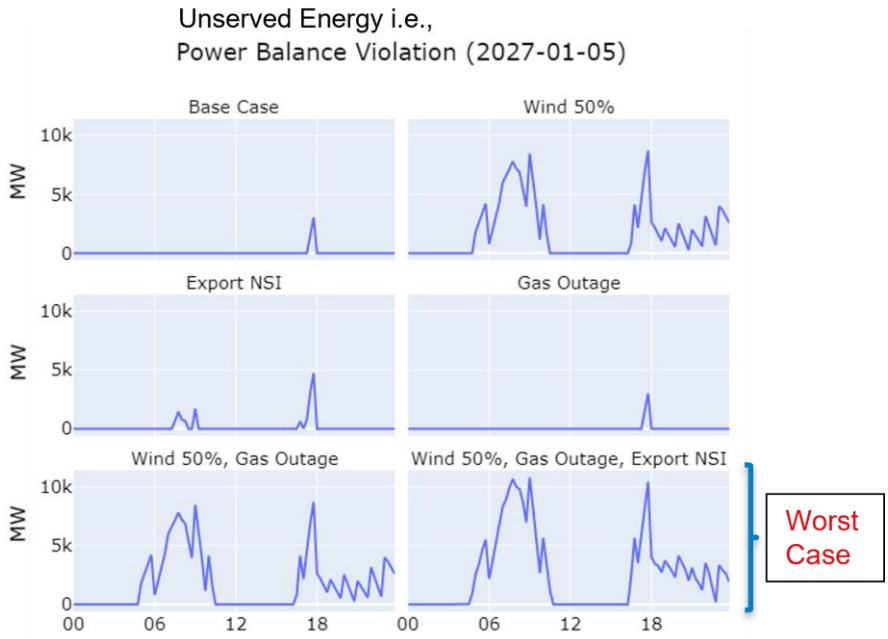


Figure B-11: Simulation results for base case and stressed scenarios for the winter 2027 event

Figure B-12 illustrates how the use of quick-start units can address flexibility challenges. The worst-case event is used as the starting point and then quick start units are added until the unserved energy is mitigated. Quick start units are added according to their lead time, starting with the fastest group (i.e., "quick 20 minutes"), followed by units with increasing lead times (e.g., up to 60 minutes or 120 minutes). The unserved energy is completely mitigated with units of lead-time of up to 5 hours.

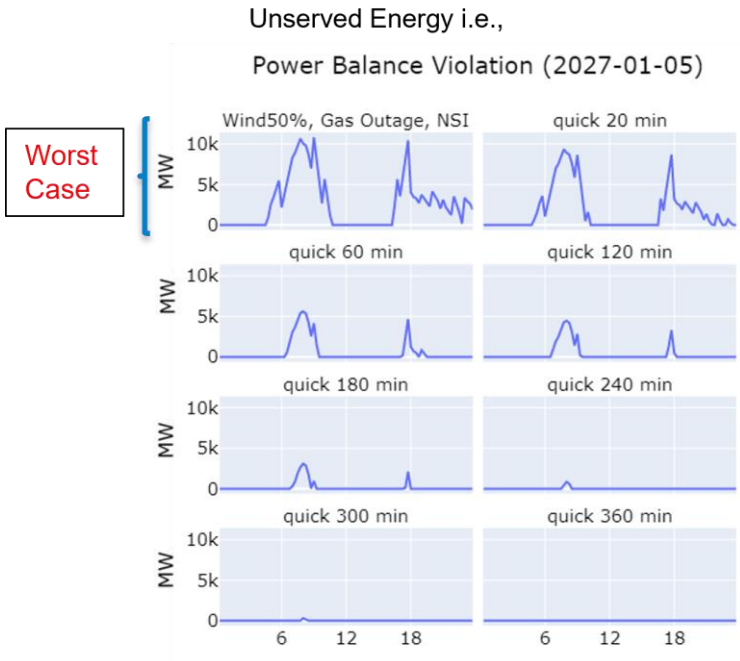


Figure B-12: Simulation for worst stress case and mitigation using quick start units for the winter 2027 event

Figure B-13 shows the available capacity of quick start units for different lead times throughout the day for the winter 2027 target day. Quick start capacity needs to be available during the high-risk hours to mitigate the unserved energy. This illustrates the need for resources to be available at the right time, and not just in an aggregate sense. MISO needs improvements in its commitment processes to ensure that adequate resources are always available to manage unanticipated changes in system conditions. This is relevant given the growing uncertainty in net load as the penetration of renewable generation increases.

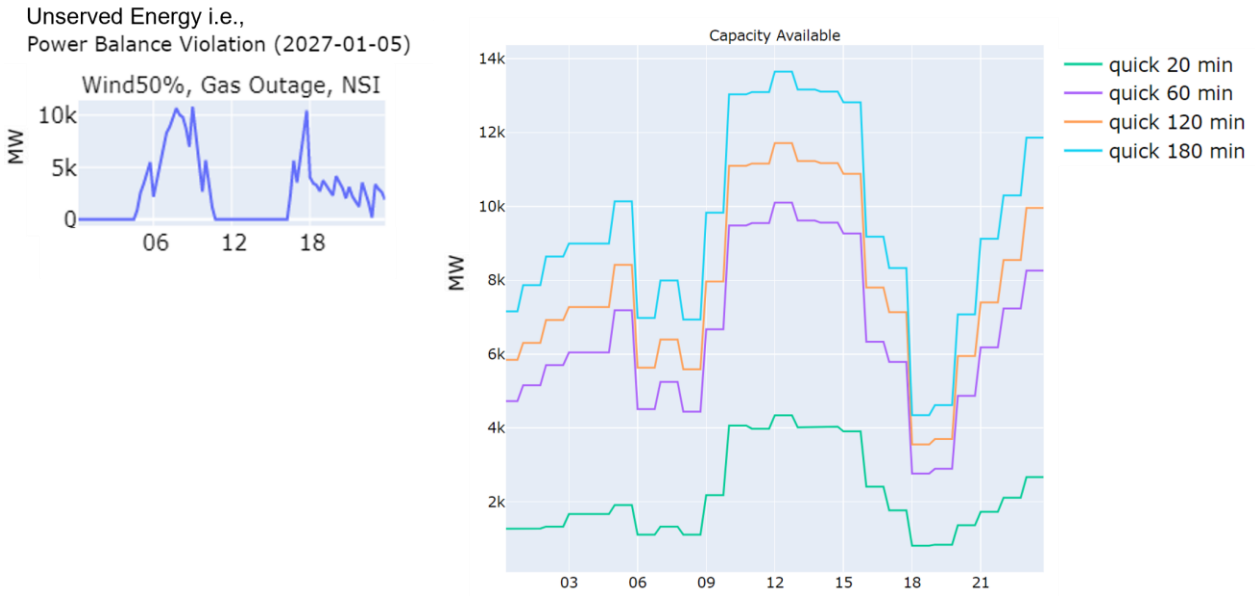


Figure B-13: (Left) Unserved energy result for the worst case of the winter 2027 event; and (Right) total capacity of quick start units for different lead times in minutes (≤20 min, ≤60 min, ≤120 min, ≤180 min)

B.5 Conclusions

This technical appendix describes approaches, tools, inputs, and assumptions used in the operational adequacy attributes analysis that informed the insights and the development of MISO's 2023 *Attributes Roadmap*. The insights and results were directionally indicative as to whether enhanced market practices or new products are needed to mitigate the risks in the operating timeframe.

C.Voltage Stability

This section in the technical appendix provides supplemental information on the analysis described in the System Stability section of MISO's 2023 *Attributes Roadmap*. Before addressing the analysis, voltage stability is defined within the broader stability landscape and an overview of MISO's current practices are provided. The context and current state information is not intended to be comprehensive, but rather to provide some information useful in understanding how MISO's voltage stability analysis relates to previous findings and existing practices.

C.1 Voltage Stability Definition

Voltage stability refers to the ability of a power system to maintain steady voltages close to nominal value at all buses in the system after being subjected to a disturbance.[21] It depends on the ability of the combined generation and transmission systems to provide the power requested by loads.[22] Voltage stability is often thought of as load-driven rather than resource-driven, though resource characteristics affect voltage stability outcomes.

A lack of adequate voltage stability could result in loss of load in an area or protective system tripping of transmission lines or system components, potentially leading to cascading outages. Voltage collapse, one potential result from voltage instability, has been identified as a contributing factor in large scale blackouts across the globe, including Scandinavia (2003), the northeastern U.S. (2003), Athens, Greece (2004), and Brazil (2009). Several factors can cause voltage instability, such as insufficient reactive power support, excessive loading, loss of transmission lines or generators, or inadequate voltage regulation. During the northeastern U.S. event in 2003, voltage instability resulted after multiple line tripping contingencies caused voltage fluctuations and reactive power deficiencies, in turn causing generators and transformers to trip or malfunction.

Voltage stability is one family of power system stability issues that can arise on the grid. Figure C-1 shows a taxonomy often used within engineering technical papers on the matter.[23] Voltage stability has the additional dimensions of small and large disturbance and short- and long-term timescales, described in greater detail below.

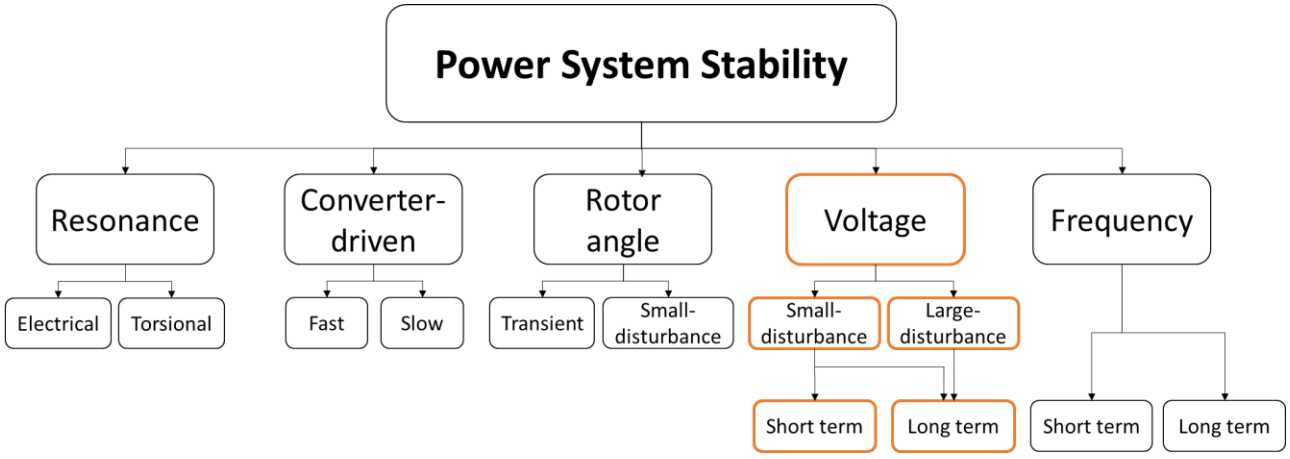


Figure C-1. Taxonomy of power system stability considerations

[21] P. Kundur *et al*., "Definition and classification of power system stability," IEEE Trans. Power Syst., vol. 19, no. 3, pp. 1387–1401, May 2004.

[22] T. Van Cutsem and C. Vournas, *Voltage Stability of Electric Power Systems*. Norwell, MA: Kluwer, 1998.

[23] N. Hatziargyriou *et al*., "Definition and Classification of Power System Stability – Revisited & Extended," in *IEEE Transactions on Power Systems*, vol. 36, no. 4, pp. 3271-3281, July 2021.

Two different disturbance types are relevant for the voltage stability definition within Figure C-1.

- **Small signal** voltage stability refers to the ability of the power system to maintain stable voltage under small perturbations around the expected operating point. For instance, small increases or decreases in line active power loading and reactive power flows.
- **Large signal** voltage stability refers to the ability of the power system to maintain stable voltage following a large system disturbance, such as a line fault.

Small signal analysis can use linear system models whereas large signal analysis must account for non-linearities associated with large system disturbances.

For each of the disturbance types, two timescales apply within the voltage stability taxonomy illustrated in Figure C-1:

- **Short-term** typically considers effects of load dynamics short circuits near load, often worst case (e.g., motors stalling, electronically controlled load tripping). The timescale is typically on the order of seconds.
- **Long-term** (e.g., several minutes) typically considers progressive reductions in voltage under maximum power transfer limits, often during contingencies (e.g., tap changers, generator current limiters). The timescale is often on the order of minutes.

C.2 Current State of the MISO system

MISO has performed detailed planning analysis of future system stability impacts through long-range studies like the Renewable Integration Impacts Assessment. Further, stability analysis is included in MISO's standard MTEP planning process. Operational analysis is also performed to evaluate risks in near real-time based on actual system conditions, an analysis which is being expanded based on recent NERC standard revisions. The following sections describe past and current efforts underway at MISO.

C.2.1 Renewable Integration Impacts Assessment

MISO's Renewable Integration Impacts Assessment (RIIA) study indicated that voltage stability and inverter-based converter stability are among the first stability-related challenges the MISO system will likely face.[24] These challenges could arise when renewable resources serve roughly 30% of MISO system annual energy. According to MISO's Future 2A resource expansion modeling, the 30% energy threshold may be reached around the year 2027.[25] In addition to the voltage stability challenges emerging earlier in the energy transition, the anticipated capital cost to mitigate the issues is expected to be the highest of all stability related challenges studied in RIIA. Figure C-2 recreates the RIIA report's summarized ranking of dynamics issues, with information on impacts, relevant penetration levels, and relative mitigation costs, among other factors.

[24] MISO, *MISO's Renewable Integration Impacts Assessment (RIIA) study*. Summary Report. February 2021.

[25] MISO, "Future 2A Expansion and Preliminary Siting", Presented at MISO's LRTP Workshop, March 10, 2023.

Area of stability	Ranked concern	Performance metric	Impacts	Possible mitigations	Concerned MISO group	Issue first seen	Impact of renewable penetration	Capital cost share to mitigate
Inverter-based stability and voltage stability	1. Transient voltage stability in weak areas	Short circuit ratio, undamped voltage and current oscillations, interactions between the controls of equipment	Local area, observed at many substations system-wide	• Control tuning • Synchronous condensers • STATCOM • HVDC	EP*, GI†	30%		
Frequency stability	2. Frequency response	Frequency nadir, rate of change of frequency (RoCoF), NERC BAL-003 obligations	Interconnection wide	• Additional planned online headroom • Batteries	Operations	50%		
	3. Small signal stability	Damping ratio of low frequency oscillations	Interconnection wide	• Must-run units with power system stabilizers • Specially tuned batteries	EP*, Operations	30%		
Rotor-angle stability	4. Transient rotor angle stability	TO's local planning criteria, NERC criteria	Local area	• Faster protection schemes • Transmission facilities	EP*, GI†	50%		–

*EP: Expansion Planning
†GI: Generator Interconnection

Figure C-2. RIIA summary of dynamic concerns

The RIIA analysis used a screening method based on short-circuit ratio (SCR) to identify "weak grid" areas and system locations with low available short-circuit current, which is an indication of potential stability issues. However, the determination of the type and magnitude of stability challenges necessitates detailed dynamics analysis using different tools such as positive sequence dynamics tools (e.g., TSAT, VSAT).

RIIA's detailed dynamics assessment showed the need for stability-related mitigations, another term for solutions that largely targeted STATCOMs, synchronous condensers, dispatch adjustments, HVDC, HVAC, batteries, and controls tuning. Small amounts of other solutions were contemplated. Figure C-3, reproduced from MISO's RIIA report, shows the level of complexity introduced by each solution for the renewable penetration milestones evaluated. In this context, complexity can roughly be treated as a proxy for investment needs. Grid-forming controls for inverter-based resources was not a solution that was considered in the RIIA study.

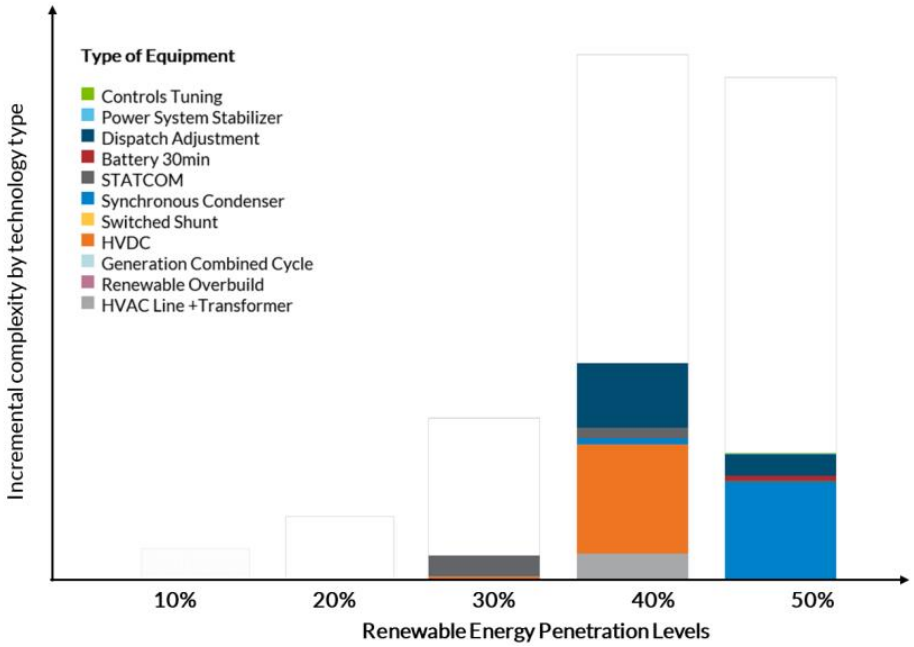


Figure C-3. RIIA dynamic stability solutions — incremental complexity by technology type for renewable penetration milestones

C.2.2 Planning

MISO's voltage stability analysis for reliability planning selects specific transfer scenarios, based on stakeholder and system operator input, with the goal of identifying potential reliability risks that could emerge in the future.

The voltage stability analysis uses a P-V study methodology where power is transferred between a defined source and sink. At different transfer levels, contingencies are introduced, and the resulting bus voltages calculated. The voltage stability limit is reached when the solution fails to converge due to voltage collapse or when a bus falls outside of planning criteria. MISO uses transmission owner (TO) local planning criteria (LPC) to define stability limits should TOs decide to institute criteria more restrictive compared to MISO defaults found in BPM-020. In absence of TO LPC, MISO uses a default margin value of 10%, with the margin being defined from the point of voltage collapse (i.e., nose point) of the PV curve. MISO also has criteria for each bulk electric system (BES) bus to maintain voltage at or above 90% of nominal voltage under contingency conditions. Figure C-4 shows an example PV curve with the 90% voltage decline criteria limit; the limit corresponding to 10% margin; and the nose point.

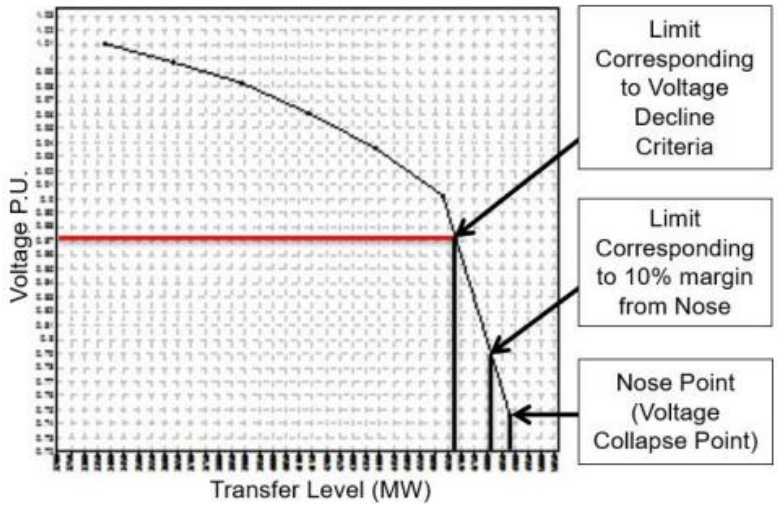


Figure C-4. Illustration of power-voltage (PV) curve with associated limits

To provide an idea of the scale of MISO's current voltage stability analysis, the MTEP23 cycle selected six transfer scenarios across the MISO region, as shown in Figure C-5. The assessment follows established methodologies pursuant to requirements in NERC Standards FAC-010 and FAC-014. FAC-010 requires that System Operating Limits (SOL) used in BES reliability planning are based on an established methodology or methodologies.[26] Voltage stability is specifically called out in Requirement 2 of this standard. FAC-014 serves the purpose of establishing how SOLs, including voltage stability limits, are communicated among the NERC registered entities.[27]

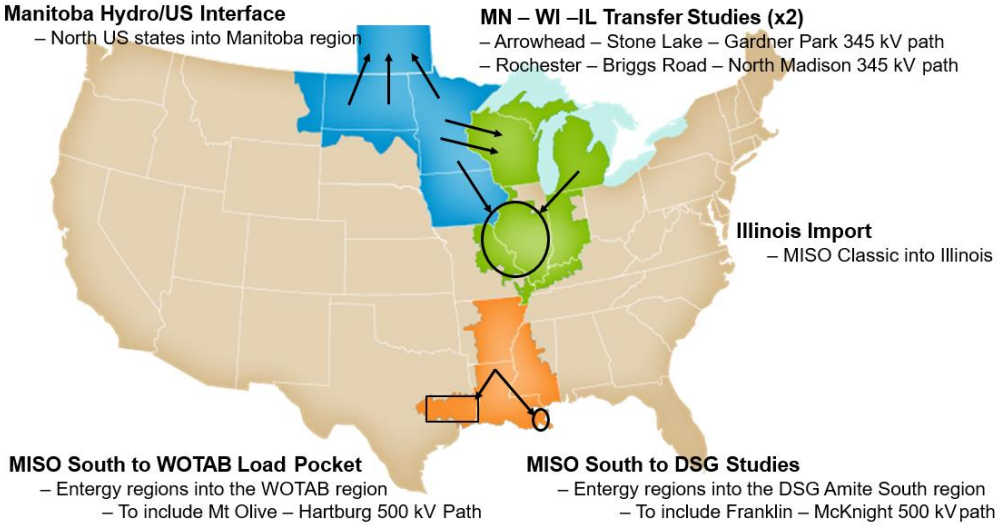


Figure C-5. Geographical representation of the six transfer scenarios selected for MTEP23

[26] NERC, Standard FAC-010-3 – System Operating Limits Methodology for the Planning Horizon.

[27] NERC, Standard FAC-014-3 – Establish Communication System Operating Limits, January 2009.

C.2.3 Operations

MISO real-time operations currently run around 30 contingencies, which primarily monitor two interfaces for stability issues. In what will amount to a large expansion of the current monitoring, recent changes to NERC's FAC-011-4 standard caused MISO to start developing a real-time, footprint wide transient stability analysis. Contingencies will be selected through a screening methodology. The project is planned for completion in December 2023, ahead of the April 2024 date on which the revised FAC-011-4 becomes active.

Voltage Stability Insight #1:

Localized pockets of stability challenges may materialize if emerging risks are not made visible and mitigated through controls and asset deployments.

C.2.4 Markets

Currently, MISO does not offer market products directly related to voltage stability.

C.3 Attributes Voltage Stability Analysis

The voltage stability portion of the 2023 attributes analysis work focused on characterizing screening results using both the SCR and dynamic impedance approaches. Screening approaches, including those contemplated in this analysis, are often used to identify areas and conditions that require deeper analysis.

C.3.1 Limitations of Screening Tools

SCR is known to have limitations in areas of high inverter-based resource (IBR) penetration. This metric is most appropriate when considering an IBR connected to a strong grid without the interactions from other nearby IBR. Adaptations of SCR approaches intended to overcome known shortcomings are described below. However, modern inverter control topologies are beginning to decouple the IBR's fault contribution from system strength contributions, concepts that are tightly coupled in grids predominantly driven by synchronous machines.

While the dynamic impedance method is relatively new, and MISO is working with industry partners – Telos Energy and Hickory Ledge – to advance industry understanding of its use and usefulness, patterns around certain limitations are emerging. One insight thus far is that characterizing grid-following (GFL) IBR using the approach presents challenges, especially for large disturbances, such as faults resulting in severe voltage depressions. The method could potentially benefit from severity-sensitivity adjustments to the dynamic impedance for GFL. For grid-forming (GFM) IBR the large-signal and small-signal screening outcomes appear to be accurate, but MISO is still investigating the efficacy for this use based on other industry research evaluating similar approaches. [28] [29] [30]

C.3.2 Short-Circuit Ratio

SCR has traditionally represented the "voltage stiffness" or system strength of a grid.[31] It is used as a screening method to understand potential reliability implications, especially as IBR deployments and synchronous machine

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[28] Gu Y. Green T. "Power System Stability with a High Penetration of Inverter-Based Resource," in *Proceedings of the IEEE*, vol. 111, no. 7, pp. 832-853, July 2023, page 14, first paragraph.

[29] Sun J. "Impedance-Based Stability Criterion for Grid-Connected Inverters," in *IEEE Transactions on Power Electronics*, vol. 26, no. 11, pp. 3075-3078, Nov. 2011, page 1, last paragraph.

[30] Shah, Shahil, et al. "Impedance Methods for Analyzing the Stability Impacts of Inverter-Based Resources," in *IEEE Electrification Magazine*, vol. 9, no. 1, pp. 53-65, March 2021, Section on "Large-Signal Impedance Analysis".

[31] NERC, *Short-Circuit Modeling and System Strength*, February 2018.

resource retirements lower the available system short-circuit current. This reduction in available short-circuit current can drive weak grid conditions that may cause plant and inverter control instability, for instance plants oscillating against one another. Other potential challenges of low system strength include[32]:

- Delayed voltage recovery
- Wide area undamped voltage and power oscillations
- Instability of plant voltage control systems
- Deeper voltage dips and higher overvoltages
- Larger voltage step change for switched compensation equipment
- Generator fault ride-through degradation
- Protection misoperation

SCR is calculated at each bus location and is the ratio of the available three-phase fault current (in MVA) over the active power rating of the resources at a given bus. This is described by equation 1 below.

$$SCR = \frac{S_{SCMVA}}{P_{RMW}} \qquad (1)$$

Variations of SCR have been developed across the industry to counteract known limitations of SCR as a system strength screening metric. The SCR method assumes a system with predominantly synchronous generation[31], therefore its use on systems with high IBR penetration may result in a conservative estimation because it does not account for IBR interaction effects[33] [34] [35]. Weighted short-circuit ratio (WSCR), defined in footnote 33, determines the system strength across an area rather than a single bus and accounts for the short-circuit contribution of each bus and active power rating of each generator in the same equation. The main limitation of this method is that it assumes all interacting IBRs are connected at the same bus. The system strength represented in WSCR can provide a lower bound to the estimation from the SCR metric while still providing a limited measure of an IBR-dominant system. Other methods (ESCR, CSCR, SCRIF, etc.) that focus only on analyzing the line impedance generally share the same limitation.[31] [35]

While variations like WSCR can address certain shortcomings of SCR, such as IBR interactions, they cannot capture the stability benefits of new IBR technologies such as grid-forming controls. This indicates a need to evaluate other approaches for system strength screening, such as the dynamic impedance method described further below.

Tools

MISO's methodology uses a Python script to automate SCR calculation across all buses in the MISO footprint. The script interfaces with the PSS/E powerflow software through API commands to simulate three phase faults at different buses in the model, then calculates the resulting SCR at that bus. The PSS/E fault calculation method was automatic sequencing (ASCC) and used the subtransient generator reactance values.

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[32] AEMO, *System Strength*, March 2020.

[33] Y. Zhang *et al.*, "Evaluating system strength for large-scale wind plant integration," IEEE PES General Meeting, National Harbor, MD, pp. 1-5, July 2014.

[34] J. Schmall *et al.*, "Voltage stability of large-scale wind plants integrated in weak networks: An ERCOT case study," IEEE PES General Meeting, Denver, CO, pp. 1-5, July 2015.

[35] C. Henderson *et al.*, "Grid Strength Impedance Metric: An Alternative to SCR for Evaluating System Strength in Converter Dominated Systems," *IEEE Transactions on Power Delivery*. Institute of Electrical and Electronics Engineers (IEEE), pp. 1-10, January 2023

In addition, ArcGIS software was used to create the SCR map visualizations using MISO bus latitude and longitude data.

Models

MISO Transmission Expansion Plan 2023 (MTEP23) Appendix A powerflow models were used for the SCR analysis.[36] There are separate models for different future years (2025, 2028, and 2033) and dispatch cases (summer, spring light load, etc.). The MTEP models include resource additions based only on projects with signed GIAs and retirements based only on plants with finalized retirement studies.

To improve SCR calculation accuracy, machine subtransient reactance values for synchronous generators were pulled from the MTEP23 five-year-out dynamics data file and added into the sequence data of the base powerflow model. Subtransient reactance class averages were used for synchronous machines that did not have individual dynamics data available. For all non-synchronous machines a value of 0.91 p.u. subtransient reactance was assumed.

Results

MISO's refreshed SCR analysis confirms the RIIA study results showing localized pockets of declining system strength. However, the picture is nuanced as increasing SCR is projected in some areas as well. Figure C-6 through Figure C-8 below show the magnitudes of SCR for the MTEP23 2025, 2028, and 2033 summer dispatch cases. Potential areas of low system strength appear to be Michigan, SW Minnesota, and Louisiana.

SCR magnitude results were split into three categories:

- "Low" SCR was defined as an SCR value less than 3
- "Medium" SCR was defined as an SCR value less than 6
- "High" SCR was defined as an SCR value greater than or equal to 6

These categories are meant to be illustrative and are not meant to exactly indicate the system strength at which stability or control issues will arise. For example, industry sources have suggested Type 3 WTG have a potential for control problems with SCR < 2.5 and cannot maintain control for SCR < 1.5.[37] MISO understands that various manufacturers' equipment is designed to operate at different minimum SCR levels, sometimes stated in their technical materials. Therefore, the SCR evaluation is reserved for initial screening with detailed analysis determining stability risks and mitigations.

[36] MISO, *Draft MTEP 2023*, 2023.

[37] Electranix, "Why GFM?," presentation to UNIFI consortium, September 11, 2023.

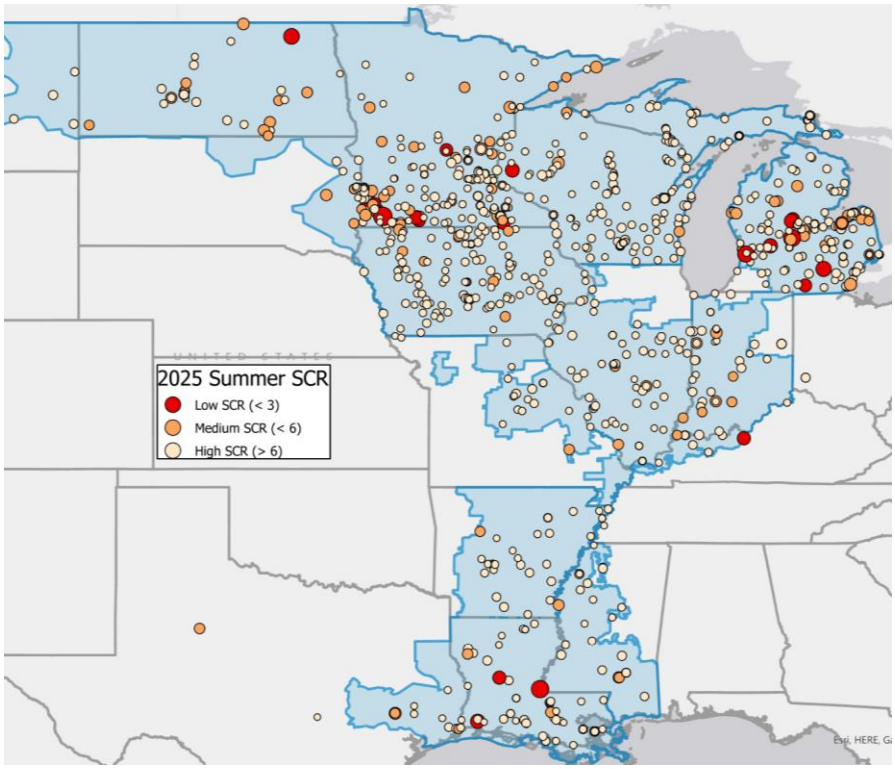


Figure C-6. SCR magnitudes for MTEP23 2025 summer dispatch model

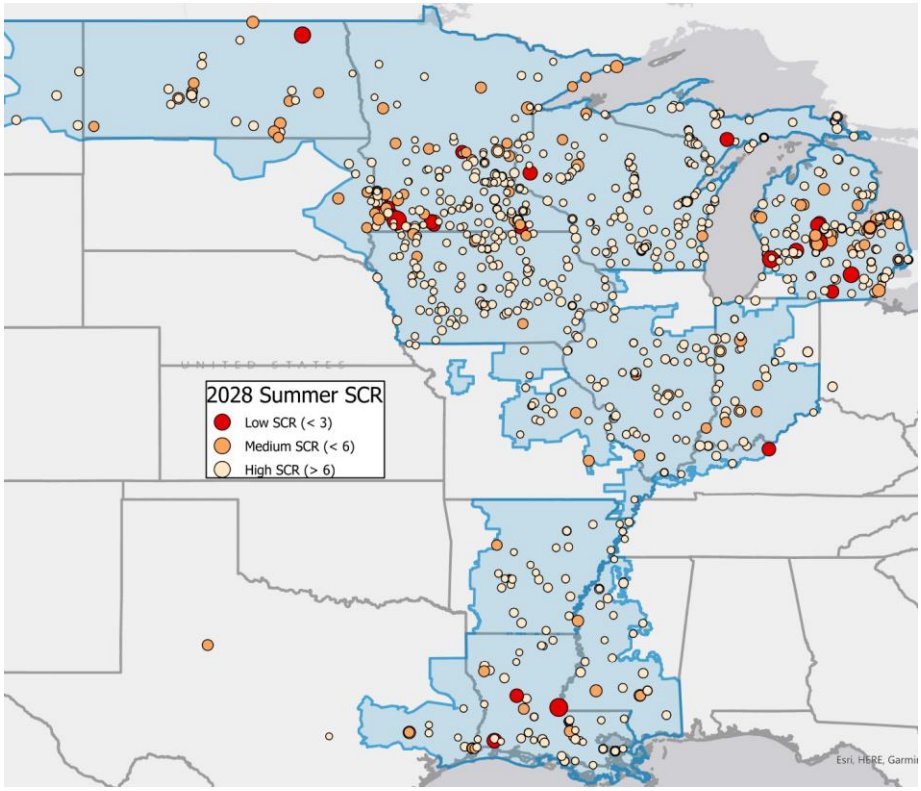


Figure C-7. SCR magnitudes for MTEP23 2028 summer dispatch model

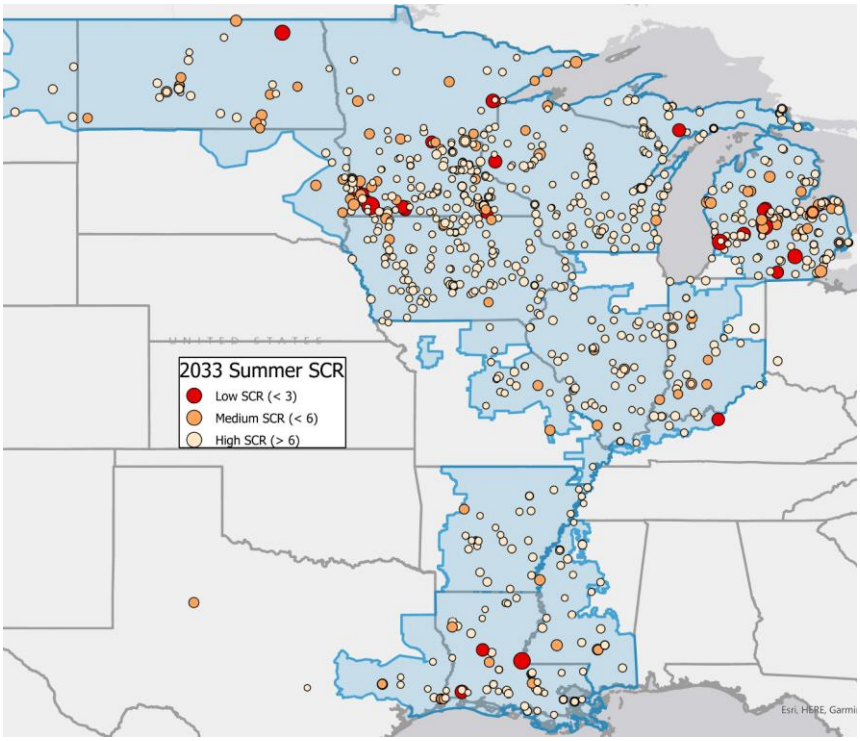


Figure C-8. SCR magnitudes for MTEP23 2033 summer dispatch model

SCR magnitudes are different based on the dispatch pattern selected for each model year, indicating that voltage stability risks can change between seasons based on dispatch patterns. Different dispatch points warrant closer consideration, with a need to align planning models with actual operational conditions to better identify dispatch-related stability risks. Figure C-9 shows an example of the SCR values for buses in the 2025 model under the spring light load (SLL) dispatch assumption. In the SLL case, SCR is lower across much of Iowa, Wisconsin, and MISO South compared to the summer dispatch case.

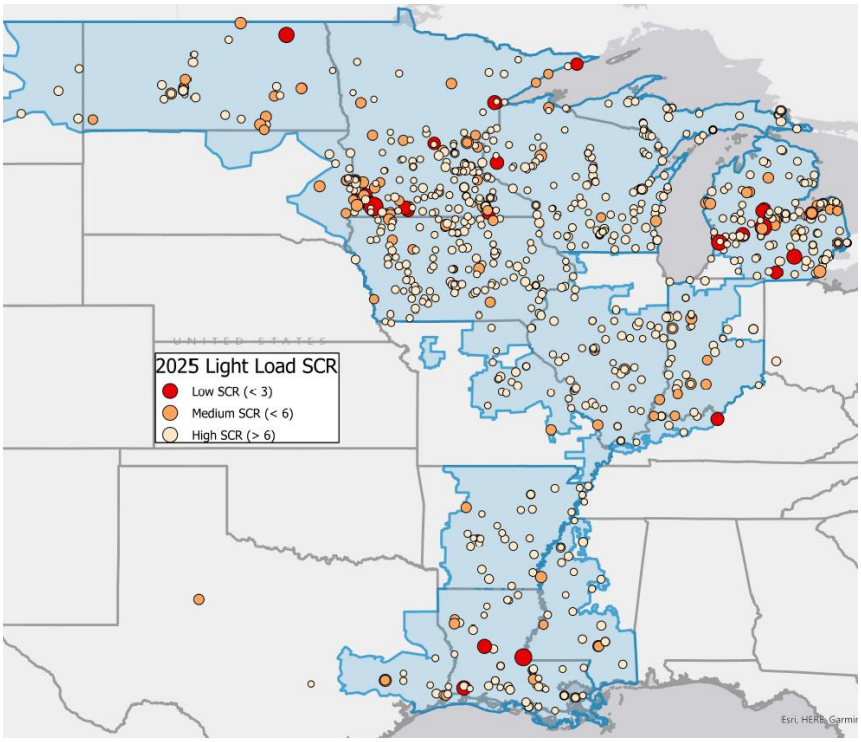


Figure C-9. SCR magnitudes for MTEP23 2025 spring light load dispatch model

The nature of the resource transition and transmission build-out will drive future system strength, affecting aspects of system stability. For example, between the 2025 and 2033 MTEP models, transmission build-out from LRTP Tranche 1 works to increase system strength while fleet changes decrease it.

Figure C-10 isolates the impacts of resource additions and retirements on SCR between 2025 and 2033. It compares the SCR of the 2025 model with the SCR of an altered 2033 model with MISO's LRTP Tranche 1 projects removed. The removal of these major transmission projects aims to isolate the impacts of resource changes, but it is acknowledged that the 2033 case still includes other transmission additions not associated with Tranche 1. There are some localized areas with synchronous generator retirements and IBR additions where SCR decreases, but there are also many areas where SCR increases over time.

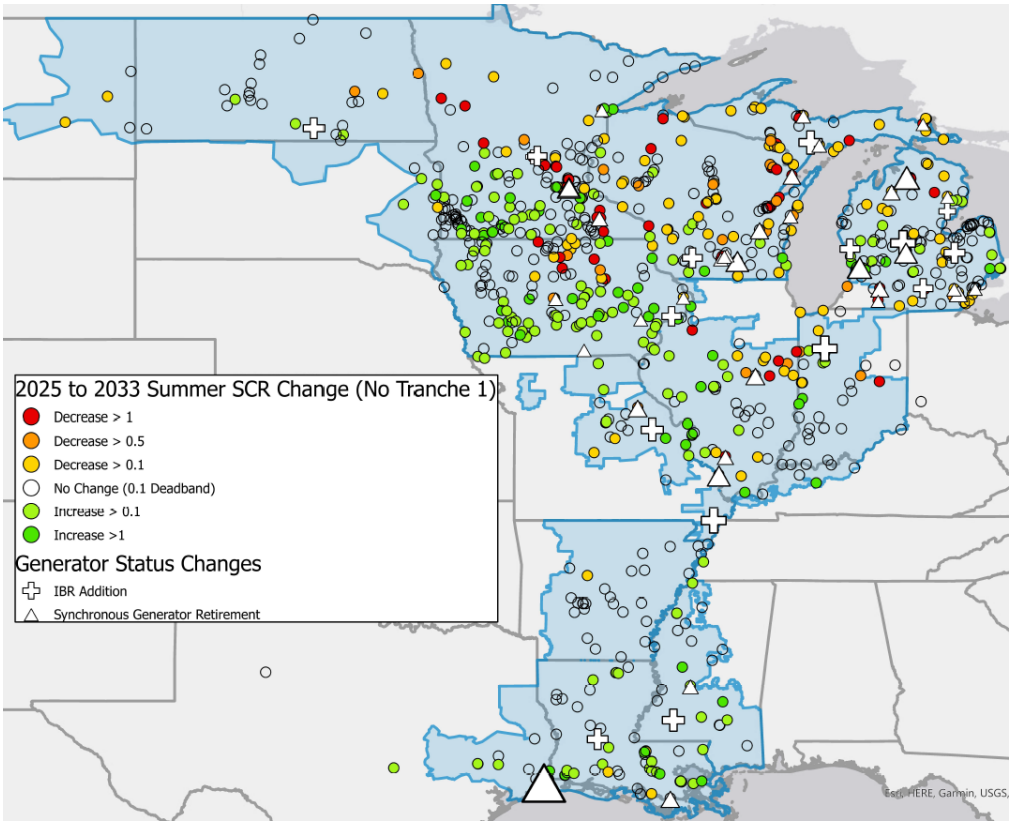


Figure C-10. Impact of resource additions and retirements on SCR, shows the change in SCR from the MTEP23 2025 summer model to the MTEP23 2033 summer model without LRTP Tranche 1 projects

Figure C-11, alternatively, isolates the impact of LRTP Tranche 1 by comparing the difference in SCR in the 2033 model before and after Tranche 1 projects are added. SCR increases when the Tranche 1 projects are added at nearly every bus across the MISO North and Central regions. There is no change in SCR due to Tranche 1 in MISO South as expected, because the transmission projects are limited to the North and Central region only.

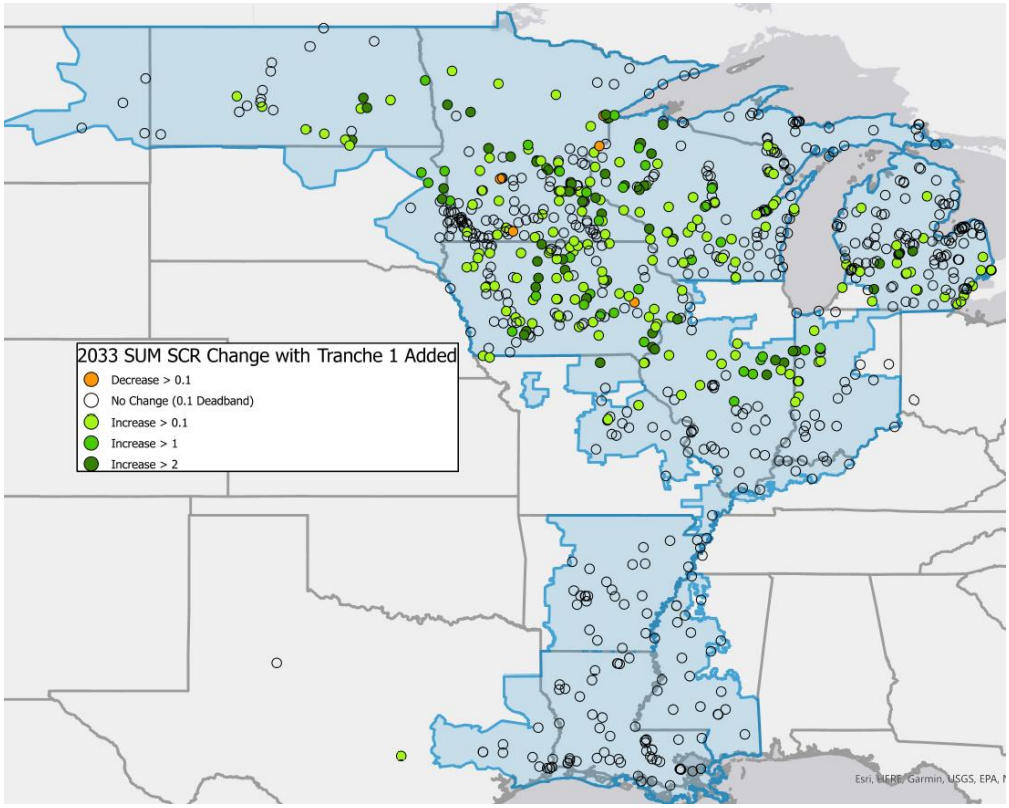


Figure C-11. Impact of LRTP Tranche 1 projects on SCR, shows the change in SCR for the MTEP23 2033 summer model with and without LRTP Tranche 1 projects

The SCR changes in Figure C-10 and Figure C-11 are summarized in Figure C-12 below. Across the entire MISO footprint, Tranche 1 increased average SCR by 0.7 (from 37.1 to 37.8) while resource changes and other transmission changes (e.g., projects generated by Local Planning Criteria) between 2025 and 2033 resulted in average SCR remaining the same (in both cases 37.1).

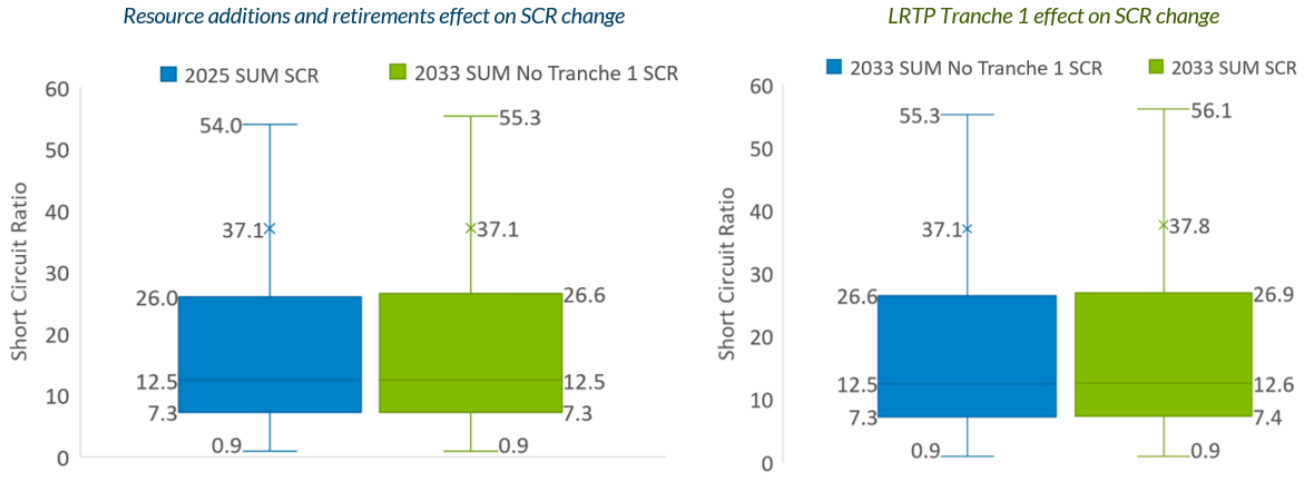


Figure C-12. Comparison of how resource change impacts SCR to how LRTP Tranche 1 projects impact SCR

C.3.3 Dynamic Impedance Method

The dynamic impedance approach development was led by Telos Energy and Hickory Ledge as part of a MISO engagement to understand potential IBR stability impacts. MISO's RIIA study did not incorporate grid-forming controls as a potential mitigation to voltage stability challenges due to the lack of industry available models and demonstration projects, which drove a need to better understand the potential of control solutions.

A paper describing the dynamic impedance method was presented at a recent industry conference in *22nd Wind and Solar Integration Workshop*[38]. MISO suggests readers refer to this paper for details on the method's purpose, formulation, and validation. This section will provide a brief overview of the method before discussing scaling the analysis to the full MISO system, which is not covered in the conference paper.

Voltage Stability Insight #2:

To gain greater visibility into potential voltage stability risks as the fleet transition accelerates, new scalable screening and analytics methods need to be developed.

The dynamic impedance method consists of two main processes, a resource characterization and a screening analysis as shown in Figure C-13. First, the resource characterization is performed using detailed electromagnetic transient (EMT) analysis to determine the modeled IBR's dynamic responses to voltage and frequency disturbances. A "dynamic impedance" value is extracted from certain perturbation frequencies in the direct-quadrature-zero (dq0) domain, sometimes also referred to as the rotor reference frame. Then, this dynamic impedance value is fed into a screening analysis. The screening is a traditional voltage stability transfer analysis using a tool called TARA to approximate the dynamic voltage stability limits. Applying a steady-state type of analysis to approximate dynamic limits reduces complexity and computational burden.

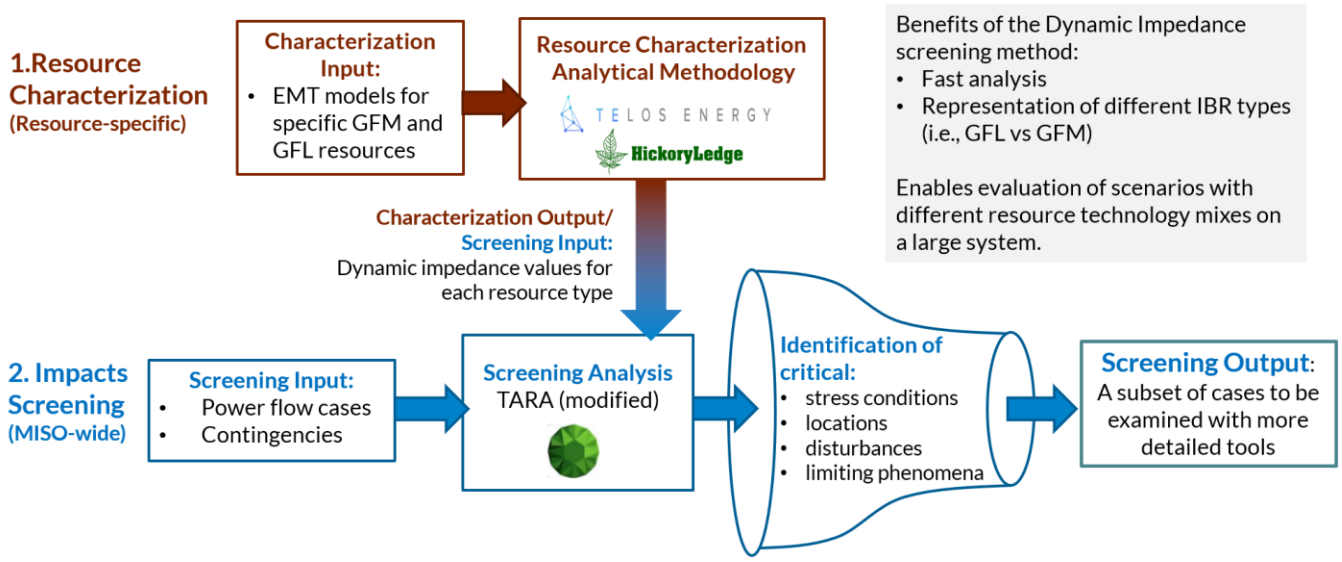


Figure C-13. Process diagram of the Dynamic Impedance screening method

[38] M. Richwine *et al.*, "Power System Stability Analysis & Planning Using Impedance-Based Methods," in 22nd Wind & Solar Integration Workshop, September 2023, *in proceeding*

Tools

A range of tools currently available at MISO are required to carry out the dynamic impedance method. Table C-1 summarizes the tools used in the dynamic impedance method.

Tool	Type	Dynamic impedance application
PSCAD	EMT Simulation	Extracting dynamic impedance from resource models.
PSS/E	Positive sequence domain power flow	Solving a power flow case for use in TARA.
TARA	Linear power flow transfer analysis	Performing PV curve analysis for screening.

Table C-1. Summary of tools used for dynamic impedance approach

First, an EMT simulation is required using PSCAD software to characterize a resource and extract the crucial dynamic impedance characteristics. Next, an iterative process is automated in PSS/E to generate a solved case while modifying the location of voltage regulation to effectively be internal to the resource rather than at the resource terminals. The reactive power limits (Q) still apply at the generator terminals. The process is iterative by nature as the internal voltage must be calculated based on terminal voltage and known impedance rather than directly controlled within a tolerance band. Figure C-14 illustrates the difference between conventional and dynamic impedance approach treatment of reactive power limits and voltage regulation.

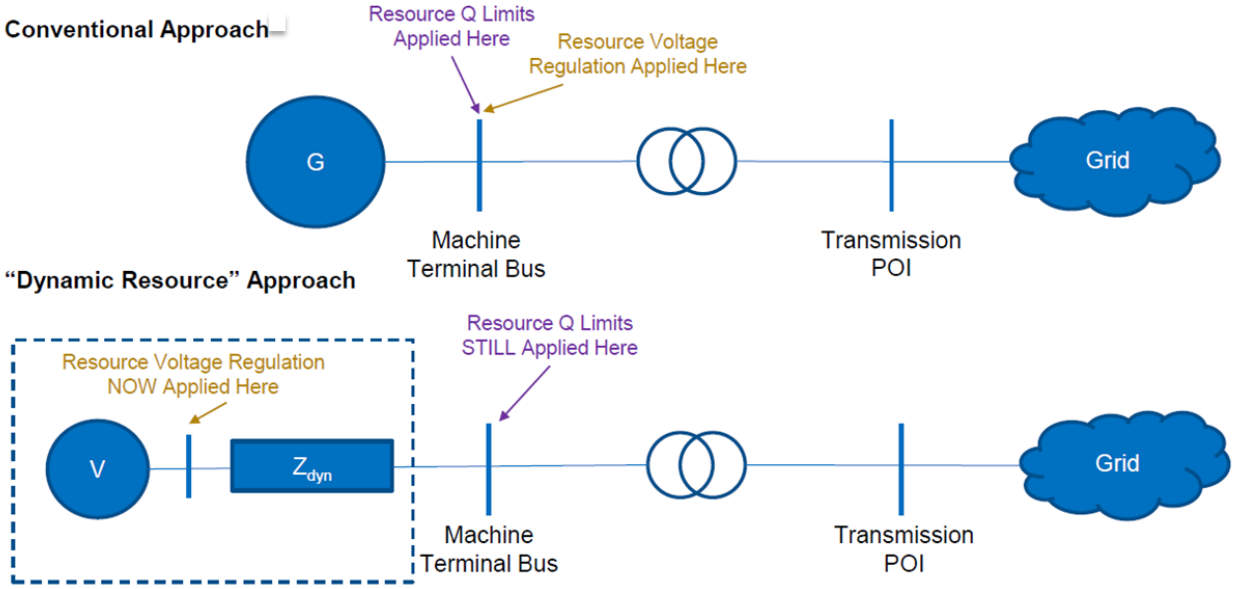


Figure C-14. Illustration of voltage regulation and active power limit application in conventional and dynamic impedance approaches (source: Telos Energy)

Finally, a tool called TARA is used to generate a PV curve used for estimating a dynamic voltage stability limit.

Models

The model used for validation was a six-bus reduced model that was roughly representing a portion of the MISO system that includes areas in South Dakota, Iowa, Minnesota, and Illinois. This area was selected based on existing

transfers resulting from wind generation to the west and load to the east. More information on the validation process and results are found in the technical paper referenced above.[39]

The scaled analysis started with the MTEP23_2033_SUM_AA model for the base case and used a modified version of this model – treating some of the synchronous machines as IBR – to generate a high penetration IBR case. The Illinois interface transfer was used as a starting point but was modified to stress a subset of this system sourced from ALTW and MEC and sunk in AMIL. The transfer was scaled up for this limited portion of the system to accentuate the results for demonstration purposes, making this an unrealistic transfer from the perspective of typical planning processes. Further, an extraordinary contingency (i.e., beyond NERC TPL Standards) was used to accentuate the difference in static and dynamic limits. Two 345 kV lines were taken out simultaneously to stress the system, which is labeled as "N-1" for this demonstration. MISO emphasizes the demonstration nature of this case. Figure C-15 shows a simplified system diagram with the green circle denoting the export area and the red circle denoting the import area. The two lines with "x" marks include the two 345 kV lines taken out for the contingency for demonstration purposes.

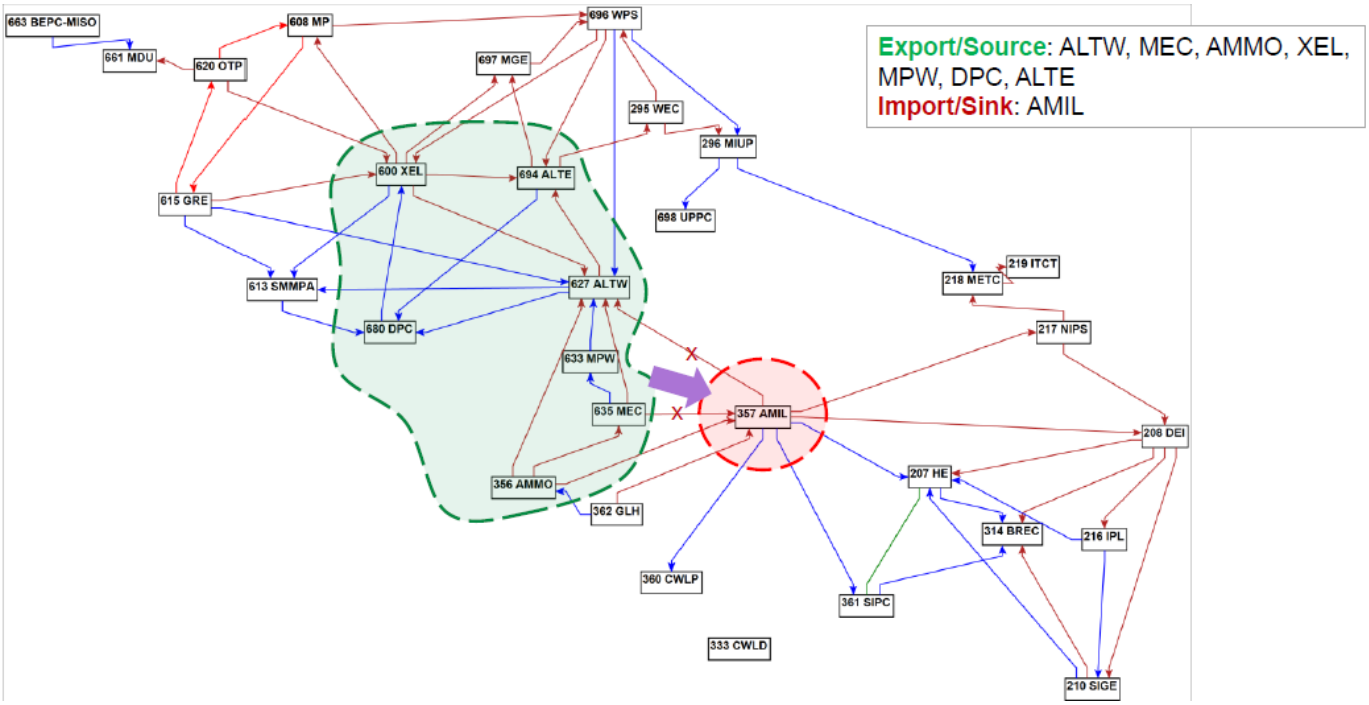


Figure C-15. Illustration of modified transfer used for demonstrating dynamic impedance approach on scaled MISO system model

The base case and high IBR case resource mix assumptions are shown in Table C-2. As previously noted, the base case assumptions are directly from the MTEP model and the high IBR penetration case treats some of the IBR in three of the areas as synchronous machines (SM) to stress the case for demonstration purposes.

[39] M. Richwine *et al.*, "Power System Stability Analysis & Planning Using Impedance-Based Methods," in 22nd Wind & Solar Integration Workshop, September 2023, *in proceeding*

Area	Base Case		High IBR Penetration	
	MVA SM	MVA IBR	MVA SM	MVA IBR
357 AMIL	12780	4840	8820	8810
627 ALTW	6670	5949	6280	6330
635 MEC	7230	8730	7230	8730

Table C-2. Resource assumptions for scaled dynamic impedance demonstration

Within the base case and high IBR penetration case, the proportion of IBR assumed to be GFM versus GFL was varied using 90%/10% weightings for each technology, generating additional scenarios. Figure C-16 shows the proportions of synchronous machines (SM), GFL, and GFM used in the scaled analysis.

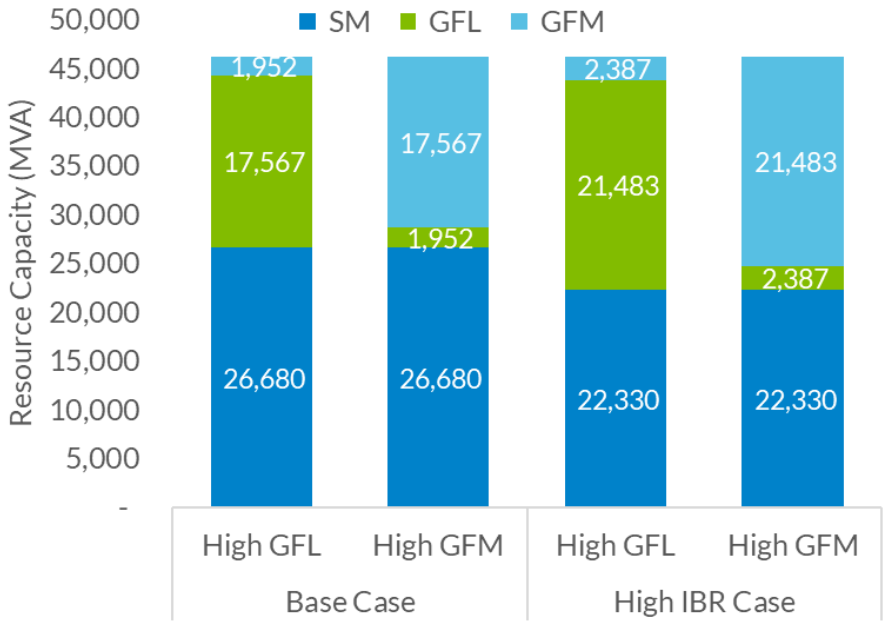


Figure C-16. Resource breakdown for each case and scenario

Dynamic impedances were applied to all large resources, amounting to approximately 1100 generators, using impedance values derived from resource characterization. For computational efficiency, small generators (e.g., less than 50 MVA) were excluded from dynamic impedance assumptions. The first step in modifying impedance of large generators was to map existing fuel types in the model to the three types of resources for which dynamic impedance is assigned: inverter-based resources and synchronous machines. Figure C-17 shows the mapping used in this analysis.

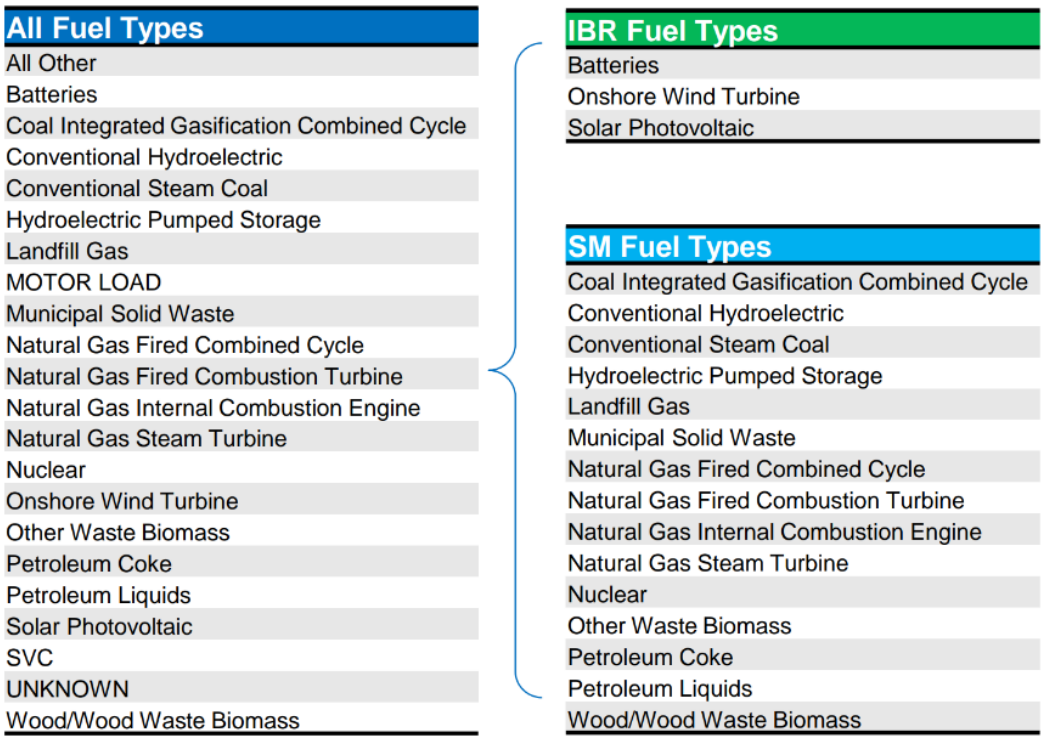


Figure C-17. Mapping of modeled fuel types to IBR and synchronous machines (SM)

The dynamic impedance values found from resource characterization were applied as assumptions in the power flow model. The demonstration used a prototypical value for each technology type, listed in Table C-3. Future work could increase granularity by using separate dynamic impedance assumptions for different IBR models and synchronous machine fuel types.

Technology type	Dynamic impedance assumption (p.u.)
Grid following IBR	1.2
Grid Forming IBR	0.1
Synchronous Machine	0.5

Table C-3. Dynamic impedance assumptions by technology type

Resource Characterization Results

The dynamic impedance method characterized six different inverters using detailed EMT models, as show in Figure C-18. The chart has admittance on the y-axis and frequency of disturbance on the x-axis (dq frame, or rotor reference frame). A high dynamic admittance translates to more effective voltage regulation over that specific frequency; this could be interpreted simply as higher system strength support. The different lines in the chart depict characterizations of commercially available makes and models of GFL and GFM technologies, representing several

major manufactures in the U.S. market. The analytical resource characterization extracts impedance information around the 10 Hz range, reflecting the time period of interest following a disturbance.[40]

MISO suspects a few causes to be driving differences in responses for a given technology type (e.g., GFM). Different control strategies could potentially drive differences. For instance, GFM technology can be implemented using virtual oscillator controls, droop-based controls, or virtual synchronous machine controls.[41] The parameterization, or settings for functional control, can also impact the IBR response and thus characterization. This means that each IBR must be characterized with the planned parameterization unless or until a standards-based approach steps in that would make generic models and parameterization more useful.

Voltage Stability Insight #3:

MISO-funded research aligns with broader industry findings showing the promise of "grid- forming" controls to support voltage stability in resource portfolios with higher levels of inverter-based resources.

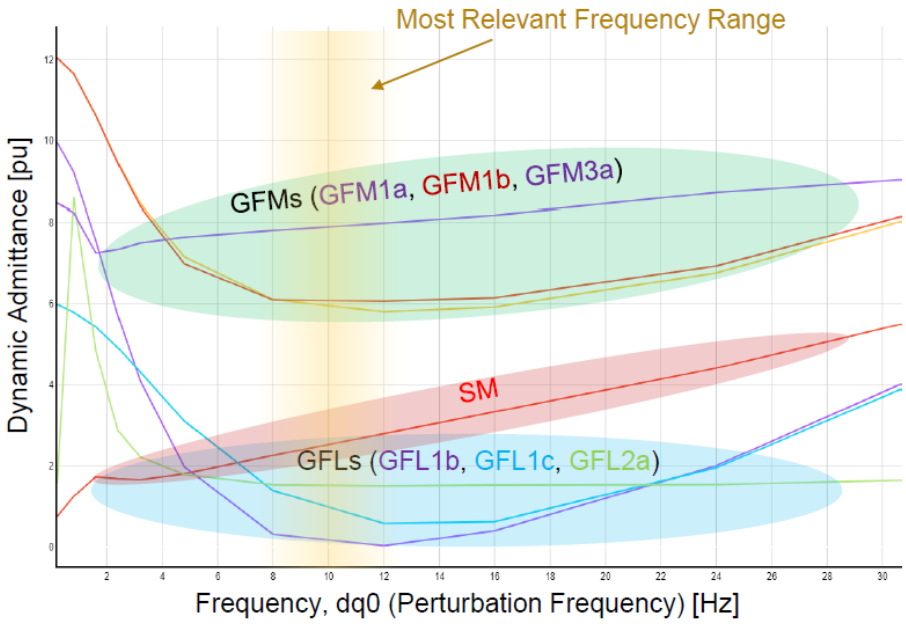


Figure C-18. EMT analysis characterizing three different commercially available grid forming (GFM) and grid following (GFL) inverter models (source: Telos Energy)

The resource characterization indicates that GFM controls are superior to GFL controls in terms of supporting stability. However, the comparison with synchronous machines is more nuanced, as the energy limitations of IBR must also be considered. Machine construction typically facilitates high current, short term overloads, whereas the energy limitations of IBR may not allow for such overloads.

[40] Selecting this range, and how to view impedance scans more generally, is an area of active research, with organizations like ESIG actively facilitating Task Force discussions that are considering a slightly different range; in to 4 Hz to 40 Hz range.

[41] NREL, *Stabilizing the Power System in 2035 and Beyond: Evolving from Grid-Following to Grid-Forming Distributed Inverter Controllers (Final Technical Report).* August 2021

It is important to note that the characterization results represent a specific range of disturbances. Further work is needed to understand the limitations associated with control non-linearities, as might be the case for a control under larger disturbances.

Transfer Capacity Results

Incorporating the resource characterization into the dynamic impedance process, Figure C-19 represents the output of the screening tool, which are PV curves that come out of the TARA tool. The vertical axis represents voltage and the horizontal axis is the MW transferred. The blue curve at the top is the same in both charts, representing a standard PV curve for a contingency without any modifications from the new method. At a high level, these curves represent the output of a voltage stability transfer analysis, showing declining voltages as transfer levels increase. The voltage magnitude is found at each transfer point, and the highest transfer point shows the voltage stability transfer limit. Voltage collapse is expected beyond this point.

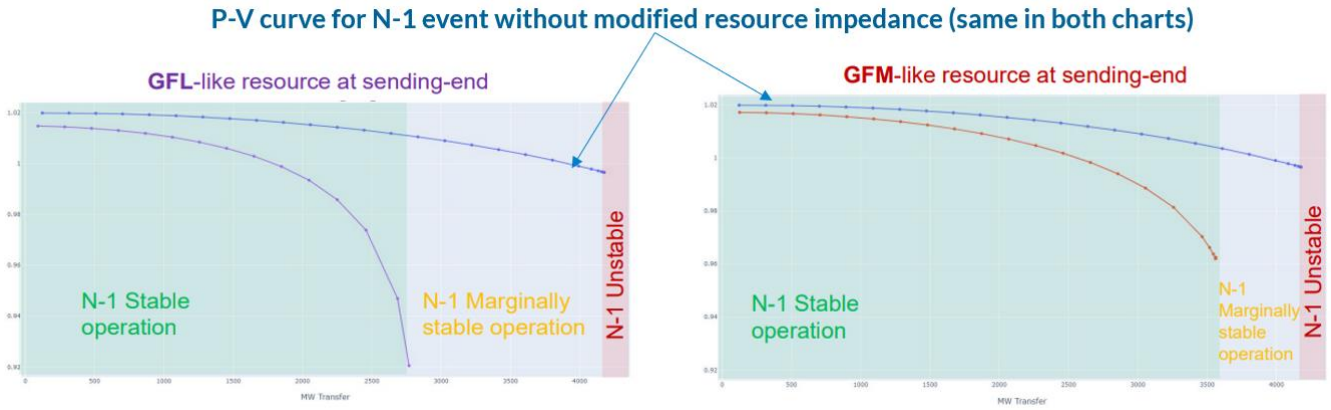


Figure C-19. Illustration of dynamic impedance screening results for GFL and GFM resources at the sending-end

The dynamic impedance screening analysis is a way to approximate dynamic stability limits using a tool and method (i.e., TARA's PV curve analysis) that is typically used to evaluate static transfer limits, under normal and contingency conditions. The lower PV curve on each chart in Figure C-19 represents analysis that incorporates the dynamic impedance values in the input assumptions. The left-hand side assumes GFL resources at the sending end, whereas the right-hand side assumes GFM. GFM resources show a greater contribution to dynamic stability, increasing the limit beyond what GFL supports. Dynamic stability limits are lower than the static limit in this test case, though voltage or thermal limits may often be the constraints in today's system analysis. The screening limit, marked by the yellow "marginally stable operation" region, would be used as a threshold for considering more detailed analysis methods (e.g., positive sequence domain simulations) to find the actual dynamic stability limit.

Applying this screening approach to the scaled MISO system described in the Models section, PV curves were generated for the different base case and high IBR case scenarios (i.e., high GFL versus high GFM). Figure C-20 shows the PV curves generated by TARA for each case, with the bookends of high GFL versus high GFM scenarios in the high IBR case. When considering dynamic voltage stability limits, the high GFL scenario in high IBR case resulted in a transfer limit of 8,976 MW whereas the high GFM scenario in high IBR case resulted in a limit of 9,833 MW. This result implies that GFM controls could improve dynamic stability limits by around 10% when compared to GFL controls in a high IBR case.

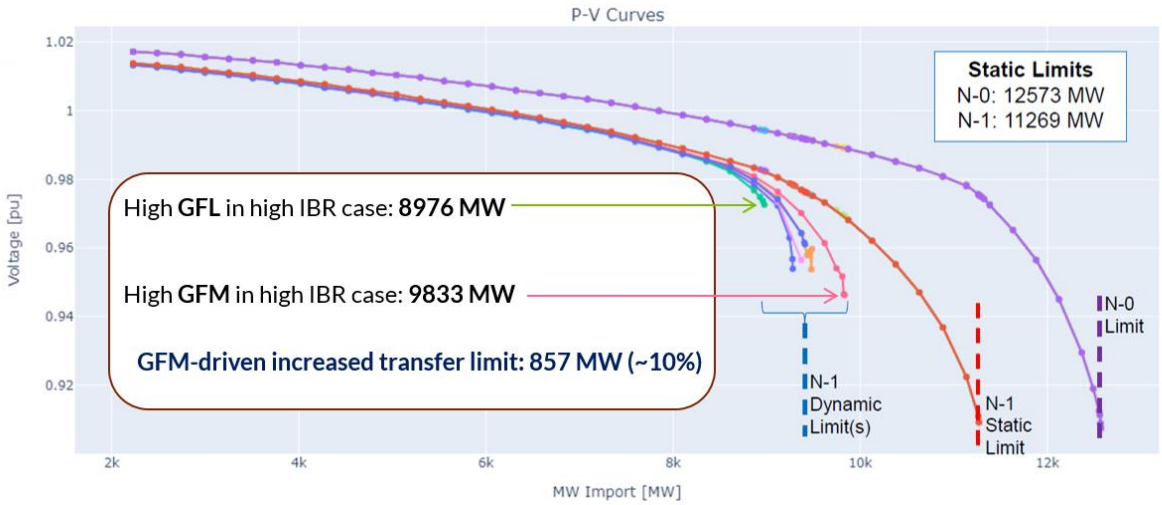


Figure C-20. Dynamic impedance screening results on the scaled-up MISO system

Another notable result from the analysis is how high levels of GFL controls in a high IBR scenario drive lower voltage stability transfer limits when compared to the base case, suggesting that high proliferation of GFL controls without GFM support could lead to new voltage stability constraints. The high GFL in a high IBR scenario has transfer levels that are 304 MW less than the base case. Consistent with the GFM stability gains discussed above, high GFM in the high IBR case leads to higher stability limits, by 347 MW, when compared to the base case with high GFM scenario. Figure C-21 shows select comparisons between the cases and scenarios, indicating transfer capability increases or decreases.

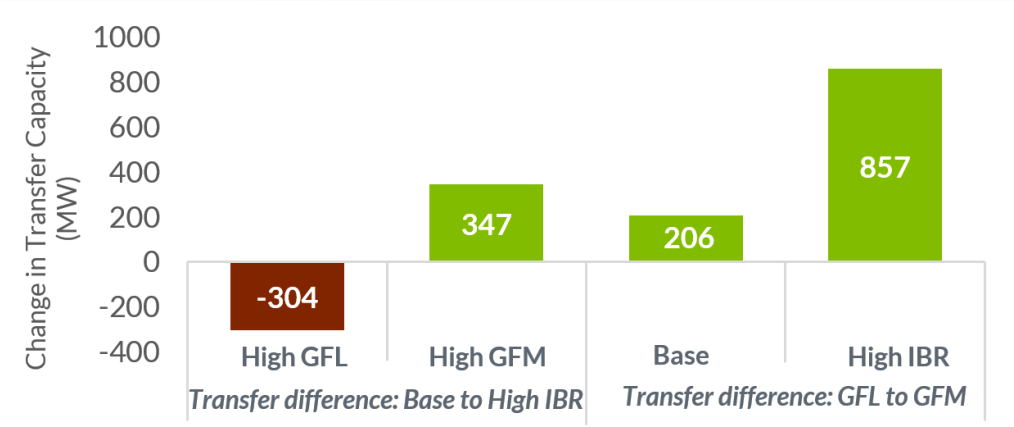


Figure C-21. Comparison of potential transfer capacity for select cases and scenarios

C.4 Conclusion

This technical appendix section described approaches, tools, and assumptions used in the voltage stability attributes analysis that informed insights and roadmap development. Please refer to the *Attributes Roadmap* for the proposed solution hypothesis based on this analysis.

D. Attribute Support from MISO's Market Structures

The following table summarizes the list of MISO's Markets, as of November 2023. The table summarizes how each Market structure supports the relevant attributes discussed in MISO's *Attributes Roadmap*. The voltage stability attribute risk-factor is excluded from Table D-1 given that MISO currently has no market products related to voltage stability.

Market	Attribute Risk-Factor	Market Product	Geographic Granularity	Requirement	Offer Cap	Max. Scarcity Price	Why does this market exist? What is the business case?
Resource Adequacy	**Availability/ Fuel Assurance/ Energy Assurance**	**Capacity Planning Resource Auction**	Local Resource Zone (LRZ)	MISO calculated LRZ needs and import/ export limits	Cost of New Entry (CONE)	Cost of New Entry (CONE)	Address resource adequacy needs in MISO's footprint
FTR	**N/A**	**Financial Transmissio n Rights**	Point-to-Point	n/a			FTRs are financial instruments used to hedge the risk of congestion cost in the Day-ahead Market.
		Auction Revenue Rights (ARRs)	Point-to-Point	Allocated based on firm historical usage	Allocation process; no market offer	n/a	ARRs are entitlements to a share of the revenues generated in the annual FTR Auction to address transmission investments.
Day-Ahead Energy and Operating Reserves Market	**Ramp Up Capability/ Rapid Start-Up**	**Energy**	Nodal	Demand Bids	$1,000 (soft cap), $2,000 (hard cap)	Value of Lost Load (VOLL) ($3,500)	The Energy market uses transmission and generation assets more efficiently and reduces the need of additional assets.
		Regulating Reserve	System-wide	300-500MW, depending on hour of day	$500	Regulation Demand Curve, up to VOLL	Address small deviations in frequency and tie-line flows, meeting NERC standards.
		Spinning Contingency Reserve	Reserve Zone with RPE	901 - 1201 MW, depending on hour of day	$100	ORDC* plus Spin Demand Curve, up to VOLL	Address larger deviations resulting from system contingencies, meeting NERC standards.
		Supplement al Contingency Reserve	Reserve Zone with RPE	1,109 MW	$100	ORDC, up to VOLL	Address larger deviations resulting from system contingencies, meeting NERC standards.
		Short Term Reserves	System-wide, Sub-Regional, Local	~3,600 MW (System-wide)	None for on-line; $100 for off-line	$100-200	Efficiently ensure capacity to manage imbalance and reserve replacement
	Ramp Up Capability	**Ramp Capability Product (Up and Down)**	System-wide	Based on estimated real-time needs	No offer	$5	Manage resource flexibility to address forecast uncertainties.

Table D-1: Current MISO's Markets and their support for attributes

Market	Attribute Risk-Factor	Market Product	Geographic Granularity	Requirement	Offer Cap	Max. Scarcity Price	Why does this market exist? What is the business case?
Real-Time Energy and Operating Reserves Market	**Ramp Up Capability/ Rapid Start-Up**	**Energy**	Nodal	Short Term Load Forecast	$1,000 (soft cap), $2,000 (hard cap)	Value of Lost Load ($3,500)	The Energy market uses transmission and generation assets more efficiently and reduces the need of additional assets.
		Regulating Reserve	System-wide	300-500MW, depending on hour of day	$500	Regulation Demand Curve, up to VOLL	Address small deviations in frequency and tie-line flows, meeting NERC standards.
		Spinning Contingency Reserve	Reserve Zone with RPE	901 - 1201 MW, depending on hour of day	$100	ORDC plus Spin Demand Curve, up to VOLL	Address larger deviations resulting from system contingencies, meeting NERC standards.
		Supplemental Contingency Reserve	Reserve Zone with RPE	1,109 MW	$100	ORDC, up to VOLL	Address larger deviations resulting from system contingencies, meeting NERC standards.
		Short Term Reserves	System-wide, Sub-Regional, Local	~3,600 MW (System-wide)	None for on-line; $100 for off-line	$100-200	Efficiently ensure capacity to manage imbalance and reserve replacement
	Ramp Up Capability	**Ramp Capability Product (Up and Down)**	System-wide	Based on short-term load forecast and uncertainty	No offer	$5	Manage resource flexibility to address forecast uncertainties.

Table D-1: Current MISO's Markets and their support for attributes (continued)

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

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

Exhibit 87
MISO's Response to the Reliability Imperative



MISO'S RESPONSE TO THE RELIABILITY IMPERATIVE

- UPDATED FEBRUARY 2024 -

Living Document

This is a "living" report that is updated periodically as conditions evolve, and as MISO, stakeholders and states continue to assess and respond to the Reliability Imperative.

misoenergy.org

Contents

A Message from John Bear, CEO 1

Executive Summary 2

Challenges Driving the Reliability Imperative 6

Pillar 1: Market Redefinition 13

Pillar 2: Operations of the Future 16

Pillar 3: Transmission Evolution 18

Pillar 4: System Enhancements 23

Appendix:

MISO Roadmap A-1

MISO's Role A-2

The MISO Value Proposition A-3

Informing the Reliability Imperative A-4

Acronyms Used in This Report A-5

A Message from John Bear, CEO



We have to face some hard realities.

There are immediate and serious challenges to the reliability of our region's electric grid, and the entire industry — utilities, states and MISO — must work together and move faster to address them.

MISO and its utility and state partners have been deeply engaged on these challenges for years, and we have made important progress. But the region's generating fleet is changing even faster and more profoundly than we anticipated, so we all must act with more urgency and resolve.

Many utilities and states are decarbonizing their resource fleets. Carbon emissions in MISO have declined more than 30% since 2005 due to utilities and states retiring conventional power plants and building renewables such as wind and solar. Far greater emissions reductions — possibly exceeding 90% — could be achieved in coming years under the ambitious plans and goals that utilities and states are pursuing.

Studies conducted by MISO and other entities indicate it is possible to reliably operate an electric system that has far fewer conventional power plants and far more zero-carbon resources than we have today. However, **the *transition* that is underway to *get to* a decarbonized end state is posing material, adverse challenges to electric reliability.**

A key risk is that many existing "dispatchable" resources that can be turned on and off and adjusted as needed are being replaced with weather-dependent resources such as wind and solar that have materially different characteristics and capabilities. While wind and solar produce needed clean energy, they lack certain **key reliability attributes** that are needed to keep the grid reliable every hour of the year. Although several emerging technologies may someday change that calculus, they are not yet proven at grid scale. Meanwhile, efforts to build new dispatchable resources face headwinds from **government regulations and policies**, as well as **prevailing investment criteria for financing new energy projects**. Until new technologies become viable, we will continue to need dispatchable resources for reliability purposes.

But fleet change is not the only challenge we face. **Extreme weather events** have become more frequent and severe. **Supply chain and permitting issues** beyond MISO's control are delaying many new reliability-critical generation projects that are otherwise fully approved. **Large single-site load additions**, such as energy-intensive production facilities or data centers, may not be reliably served with existing or planned resources. **Incremental load growth** due to electric vehicles and other aspects of electrification is exerting new pressure on the grid. And **neighboring grid systems are becoming more interdependent** and reliant on each other, highlighting the need for more interregional planning such as the Joint Targeted Interconnection Queue study that MISO conducted with Southwest Power Pool.

This report documents how MISO is addressing these risks through the **Reliability Imperative** — the critical and shared responsibility that MISO, our members and states have to address the urgent and complex challenges to electric reliability in our region. MISO first published a Reliability Imperative report in 2020, and this is the fourth time we've updated it to reflect the changing landscape.

None of the work we must do is easy, but it is necessary. The region's 45 million people are counting on MISO and its utility and state partners to get it right. Thank you for your interest in these important issues.



Executive Summary

THE CHALLENGE: A "HYPER-COMPLEX RISK ENVIRONMENT"

There are urgent and complex challenges to electric system reliability in the MISO region and elsewhere. This is not just MISO's view; it is a well-documented conclusion throughout the electric industry. The North American Electric Reliability Corporation, a key reliability entity throughout the U.S., Canada and part of Mexico, has described these challenges as a "hyper-complex risk environment." These challenges include:



Fleet change: The new weather-dependent resources that are being built, such as wind and solar, do not provide the same critical reliability attributes as the conventional dispatchable coal and natural gas resources that are being retired. While emerging technologies such as long-duration battery storage, small modular reactors and hydrogen systems may someday offer solutions to this issue, they are not yet viable at grid scale.



Regulations, policies and investment criteria: Many dispatchable resources that provide critical reliability attributes are retiring prematurely due to environmental regulations and clean-energy policies. This regulatory environment, along with prevailing investment criteria for financing new energy projects, increases the challenges to build new dispatchable generation — even if it is critically needed for reliability purposes.



Fuel assurance: Gas resources can face challenging economics to procure fuel because they share the pipeline system with residential and commercial heating and manufacturing uses. Coal plants typically keep large stockpiles of fuel onsite, but coal supplies have tightened due to changing economics, import/export dynamics, supply chain issues and other factors. Aging resources can also be more prone to outages. While renewable resources such as wind turbines do not use "fuel" per se, they are sometimes unavailable due to adverse weather conditions.



Extreme weather events: While extreme weather has always been commonplace in the MISO region, severe weather events that impact electric reliability have been increasing. The Electric Power Research Institute found that hurricanes are increasing in intensity and duration, heat events are increasing in frequency and intensity and cold events are increasing in frequency. Examples include Winter Storm Elliott in 2022, Winter Storm Uri in 2021, Hurricane Ida in 2021, and Hurricanes Laura, Delta and Zeta in 2020.



Load additions: Some parts of the MISO region are enjoying a resurgence in manufacturing and/or other types of economic growth, with companies planning and building new factories, data centers and other energy-intensive facilities. While such development is welcome from an economic perspective, it can also pose significant reliability risks if the load additions it spurs cannot be reliably served with existing or planned resources.



Incremental load growth: While electricity demand has been flat for many years, it is expected to increase due to the electrification of other sectors of the economy. Electric vehicles are growing in popularity, and the residential and commercial sectors are increasingly using electricity for heating and cooling. These trends will accelerate more due to the electrification tax credits in the 2022 Inflation Reduction Act.



Supply chain and permitting issues: Many projects that have been fully approved through MISO's Generator Interconnection Queue process are not going into service on schedule due to supply chain issues and permitting delays that are beyond MISO's control. As of late 2023, about 25 gigawatts (GW) of approved resources are signaling delays that average 650 days to commercial operation.

RELIABILITY IMPERATIVE OVERVIEW

The **Reliability Imperative** is the term MISO uses to describe the shared responsibility that MISO, its members and states have to address the urgent and complex challenges to electric system reliability in the MISO region. MISO's *response* to the Reliability Imperative consists of numerous interconnected and sequenced initiatives that are organized into four primary pillars, as shown here:

RELIABILITY IMPERATIVE PILLAR	KEY INITIATIVES *(partial list)*
MARKET REDEFINITION Enhance and optimize MISO's markets to ensure continued reliability and efficiency while enabling the changing resource mix, responding to more frequent extreme weather events, and preparing for increasing electrification	• Ensure resources are accurately accredited • Identify critical system reliability attributes • Ensure accurate pricing of energy & reserves
OPERATIONS OF THE FUTURE Focus on the skills, processes and technologies needed to ensure MISO can effectively manage the grid of the future under increased complexity	• Manage uncertainty associated with increasing reliance on variable wind and solar generation • Prepare control room operators to rapidly assess and respond to changing system conditions • Use artificial intelligence & machine learning to enhance situational awareness & communications • Evaluate interdependency of neighboring systems
TRANSMISSION EVOLUTION Assess the region's future transmission needs and associated cost allocation holistically, including transmission to support utility and state plans for existing and future generation resources	• Develop "Futures" planning scenarios using ranges of economic, policy, and regulatory inputs • Develop distinct "tranches" (portfolios) of Long Range Transmission Plan (LRTP) projects • Enhance joint transmission planning with seams partners • Improve processes for new generator interconnections and retirements
SYSTEM ENHANCEMENTS Create flexible, upgradeable and secure systems that integrate advanced technologies to process increasingly complex information and evolve with the industry	• Modernize critical tools such as the Day-Ahead and Real-Time Market Clearing Engines • Fortify cybersecurity and proactively address the rapidly evolving cyber threat landscape • Develop cutting-edge data and analytics strategies

RECENT KEY ACCOMPLISHMENTS

MISO and its stakeholders have made great progress under the Reliability Imperative in recent years. Some of our key accomplishments to date include:

Seasonal Resource Adequacy Construct: In August 2022, the Federal Energy Regulatory Commission (FERC) approved MISO's proposal to shift from its summer-focused resource adequacy construct to a new four-season construct that better reflects the risks the region now faces in winter and shoulder seasons due to fleet change, more frequent and severe extreme weather, electrification and other factors. This new construct seeks to ensure that resources will be available when they are needed most by aligning resource accreditation with availability during the highest risk periods in each season.

LRTP Tranche 1: The first of four planned portfolios of Long Range Transmission Planning (LRTP) projects was approved by the MISO Board of Directors in July 2022. This tranche of 18 projects represents a total investment of $10.3 billion — the largest portfolio of transmission projects ever approved by a U.S. Regional Transmission Organization. These projects will integrate new generation resources built in MISO's North and Central subregions, supporting the reliable and affordable transition of the fleet and further hardening the grid against extreme weather events.

Reliability-Based Demand Curve: MISO's Planning Resource Auction (PRA) was not originally designed to set higher capacity clearing prices as the magnitude of a shortfall increases. This lack of a "warning signal" can mask an imminent shortfall — as occurred with the 2022 PRA. Accurate capacity pricing is also crucial to make effective investment and retirement decisions. MISO worked with its stakeholders to design a Reliability-Based Demand Curve that will improve price signals in the PRA. Full implementation is planned for the 2025 PRA, subject to FERC proceedings.

Futures Refresh: The MISO Futures utilize a range of economic, policy and technological inputs to develop three scenarios that "bookend" what the region's resource mix might look like in 20 years. In 2023, MISO updated its Futures to lay the groundwork for LRTP Tranche 2 and to better reflect evolving decarbonization plans of MISO members and states. The refreshed Futures also model how the financial incentives for clean energy in the 2022 Inflation Reduction Act could further accelerate fleet change. The refreshed Futures are indicated with an "A" (e.g., Future 2 was updated and renamed Future 2A).

System Enhancements: The Market System Enhancement (MSE) program made significant progress in 2023. In March, the Energy Management System upgrade was moved into service. This provides a more stable platform with improved visualization while enhancing functionality and user experience. MISO also took delivery of the Reliability Assessment Commitment for the Real-Time Market Clearing Engine, which will improve application security and reduce solution time. MISO also completed Model Manager Phase 2, which connects internal applications to improve model data propagation. MSE will continue to deliver more new products, including Day-Ahead and Real-Time Market Clearing Engine items.

MISO PRIORITIES GOING FORWARD

While far from a complete list, some of MISO's key priorities for 2024 include:

Attributes: In 2023, following an in-depth look at the challenges of reliably operating an electric system in a rapidly transforming landscape, MISO published an *Attributes Roadmap* of recommended solutions to address the potential scarcity of three priority attributes that appear to pose the most acute risks: system adequacy,

flexibility and system stability. The recommendations include further modernizing the resource adequacy construct, focusing market signals on emerging flexibility needs, and requirements for new capabilities from inverter-based resources. Next, MISO will prioritize attribute solution integration, including handoffs to MISO business units and stakeholder groups and the scoping of ongoing analysis.

Accreditation: MISO must ensure resource accreditation values reflect what we can expect to receive during high-risk periods. For non-thermal resources, MISO's recommended approach blends a probabilistic methodology with availability during tight conditions, leveraging principles from the thermal accreditation reform implemented in 2022. MISO has proposed a three-year transition to the new methodology that will be applied to all non-emergency resources following the transition period. A FERC filing is planned for 2024.

LRTP Tranche 2: Work to develop the Tranche 2 portfolio of LRTP projects is progressing, with approval by MISO's Board of Directors anticipated in 2024. Planning is complex, but MISO will continue to balance the need to plan quickly with the need to develop a robust, lowest-cost portfolio. Tranche 2 is based on the refreshed Future 2A, which reflects all decarbonization plans of MISO members and states. As with Tranche 1, MISO anticipates Tranche 2 will deliver sufficient benefits to qualify under the Multi-Value Project cost allocation mechanism, with costs allocated only to the subregion where benefits are realized.

CALL TO ACTION: WE MUST WORK TOGETHER AND MOVE FASTER

In light of the urgent and complex risks to electric reliability in the MISO region, utilities, states and MISO must all act with more urgency and more coordination to avoid a looming mismatch between the pace of adding new resources and the retirement of older resources in the MISO region. This means we must:

- Refine generation resource plans across MISO by accelerating the addition of reliability attributes and moderating retirements to avoid undue reliability risk
- Maintain transition resources as reliability "insurance" until promising new technologies become viable at grid scale
- Identify areas of risk in which electricity providers, states and MISO must coordinate

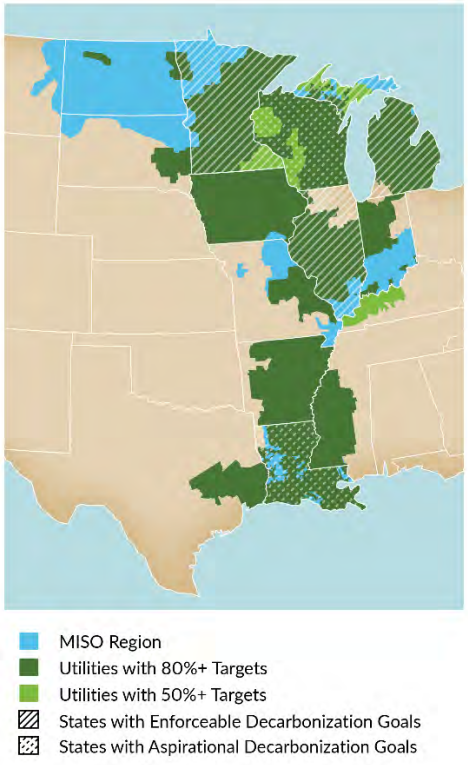
CONTINUED STAKEHOLDER INPUT IS CRUCIAL

Many of the ideas and proposals in this report reflect a great deal of technical input from MISO stakeholders. MISO appreciates stakeholder feedback on the Reliability Imperative, and we look forward to continuing the dialogue. This document is a "living" report that MISO regularly updates.

Challenges Driving the Reliability Imperative

COMPLEX POLICY LANDSCAPE

As the map indicates, many utilities and states in the MISO region have adopted policies and goals to decarbonize their resource fleets. Currently, about 75% of the region's total load is served by utilities that have ambitious decarbonization and/or renewable energy goals.



Without question, utilities and states are making remarkable progress toward their goals. Carbon emissions in MISO have already declined more than 30% since 2005, and far greater reductions are expected going forward.

Currently, wind and solar generation account for about 20% of the region's total energy. Under MISO modeling scenario Future 2A, which reflects all the clean-energy goals that utilities and states have publicly announced, wind and solar are projected to serve 80% of the region's annual load by 2042. Fleet change of that magnitude would foster a 96% reduction in carbon emissions compared to 2005 levels — which would be an extraordinary accomplishment for a region that was predominately reliant on fossil fuels not that long ago.

But at the same time, complex challenges to electric system reliability have been steadily materializing throughout the U.S. in recent years, including in MISO. These challenges are driven by a combination of economic, technological and policy-related factors along with extreme weather events. Here is a look at some of these challenges and the drivers associated with them:

TIGHTENING SUPPLY

Over the last 10-plus years, surplus reserve margins in MISO have been exhausted through load growth and unit retirements. Since 2022, MISO has been operating near the level of minimum reserve margin requirements. While MISO has implemented several reforms to help avert near-term risk, more work is urgently needed to mitigate reliability concerns in the coming years. In fact, the region only averted a capacity shortfall in 2023 because some planned generation retirements were postponed and some additional capacity was made available to MISO.

However, MISO cannot count on such actions being repeated going forward. Indeed, the North American Electric Reliability Corporation (NERC) projects the MISO region will experience a 4.7 GW shortfall beginning in 2028 if currently expected generator retirements actually occur. Notably, NERC says that shortfall will occur *even if* the 12-plus GW of new resources that are expected to come online by then actually materialize. This is because the new resources that are being built have significantly lower accreditation values than the older resources that are retiring, as is discussed in more detail below.

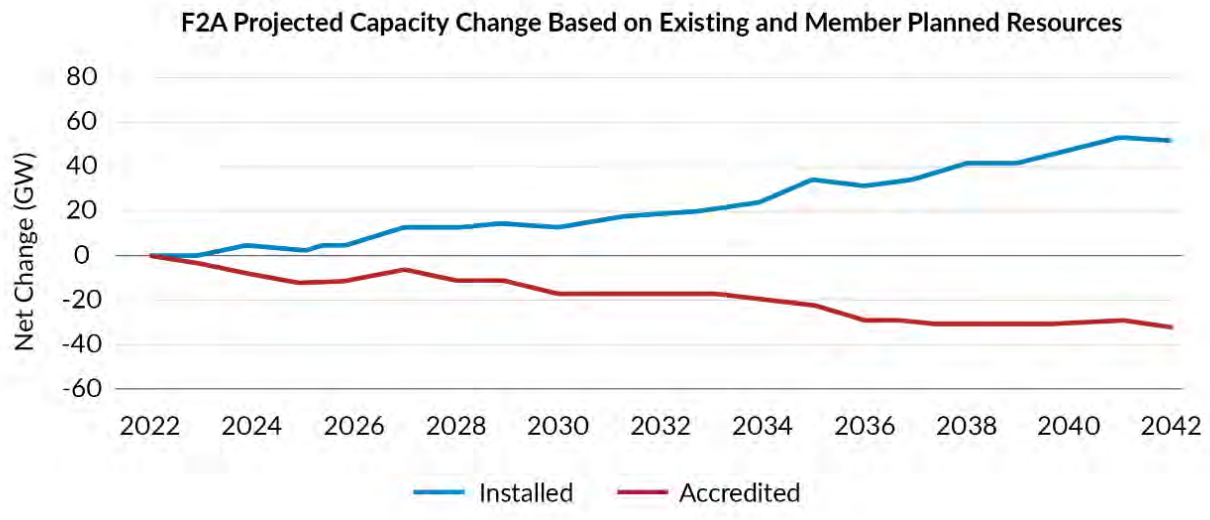
An annual planning tool called the **OMS-MISO Survey** tells a similar story. The survey compiles information about new resources utilities and states plan to build and older assets they intend to retire in the coming years. The 2023 survey shows the region's level of "committed" resources declining going forward, with a potential shortfall of 2.1 GW occurring as soon as 2025 and growing larger over time. MISO administers the survey in partnership with the Organization of MISO States (OMS), which represents the region's state regulatory agencies.

Other drivers of the region's tightening supply picture include:

- U.S. Environmental Protection Agency (EPA) regulations that prompt existing coal and gas resources to retire sooner than they otherwise would.
- Wall Street investment criteria that make it more challenging to build new dispatchable generation, even if it is critically needed for reliability purposes.
- The approximately $370 billion in financial incentives for clean-energy resources in the federal Inflation Reduction Act.

DECLINING ACCREDITED CAPACITY

Fleet change is creating a gap between the region's levels of installed and accredited generation capacity. **Installed capacity** is the maximum amount of energy that resources could theoretically produce if they ran at their highest output levels all the time and never shut down for planned or unplanned reasons. **Accredited capacity**, by contrast, reflects how much energy resources are realistically expected to produce during times when they are needed the most by accounting for their performance, which includes limiting factors such as their forced outage rates during adverse weather conditions.



The chart above is from MISO Future 2A, which reflects the publicly announced decarbonization plans of MISO-member utilities and states. As the chart shows, the region's level of *installed* capacity — the blue line — is forecast to increase by nearly 60 GW from 2022 to 2042 due to the many new resources —

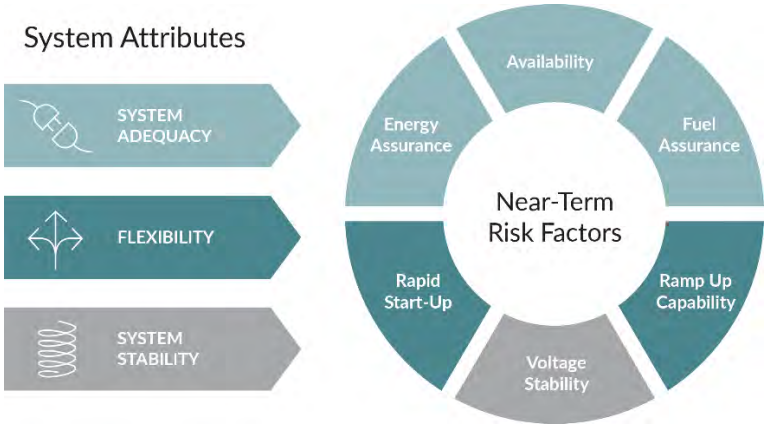
primarily wind and solar — that utilities and states plan to build in that 20-year time period.[1] But because those new wind and solar resources have significantly lower accreditation values[2] than the conventional resources that utilities and states plan to retire in the same 20-year period, the region's level of *accredited* capacity — the red line — is forecast to decline by a net 32 GW by 2042.

MISO modeling indicates that a reduction of that magnitude could result in load interruptions of three to four hours in length for 13-26 days per year when energy output from wind and solar resources is reduced or unavailable. Such interruptions would most likely occur after sunset on hot summer days with low wind output and on cold winter days before sunrise and after sunset.

NEED FOR SYSTEM RELIABILITY ATTRIBUTES

Reliably navigating the energy transition requires more than just having sufficient generating capacity; it also requires urgent action to avoid a looming shortage of broader **system reliability attributes**. In 2023, MISO completed a foundational analysis of attributes, with a focus on three priority attributes where risk for the MISO system is most acute:

- **System adequacy** is the ability to meet electric load requirements during periods of high risk. MISO focused on the near-term risk factors of availability, energy assurance and fuel assurance.
- **Flexibility** is the extent to which a power system can adjust electric production or consumption in response to changing system conditions. MISO focused on the near-term risk factors of rapid start-up and ramp-up capability.
- **System stability** is the ability to remain in a state of operating equilibrium under normal operating conditions and to recover from disturbances. MISO focused on the nearest-term risk factor of voltage stability.



No single type of resource provides every needed system attribute; the needs of the system have always been met by a fleet of diverse resources. However, in many instances, the new weather-dependent resources that are being built today do not have the same characteristics as the dispatchable resources they are replacing. While studies show it is possible to reliably operate the system with substantially lower levels of dispatchable resources, the transformational changes require MISO and its members to study, measure, incentivize and implement changes to ensure that new resources provide adequate levels of the needed system attributes.

[1] It is not a typical industry practice for utilities and states to publicly announce their resource plans a full 20 years in advance, which is the time horizon that MISO used for the MISO Futures. Thus, this forecast should be viewed as a "snapshot in time" that will change going forward as utilities and states solidify their resource plans.
[2] In the Future 2A model, retiring conventional resources are accredited at 95% or more of their nameplate capacity, while wind is accredited at 16.6% and solar declines over time to 20%. Accreditation values will vary depending on the methodologies and assumptions that were used to create them.

In December 2023, MISO published an Attributes Roadmap report that recommends urgent action to advance a portfolio of market reforms and system requirements and to provide ongoing attributes visibility through regular reporting.

EMERGING TECHNOLOGIES SHOW PROMISE BUT ARE NOT YET VIABLE AT GRID SCALE

A number of emerging technologies are being developed that could potentially mitigate the challenges described above. They include long-duration battery storage, carbon capture, small modular nuclear reactors and "green" hydrogen produced from renewables, among others.

However, while these technologies show promise for the future, they are not yet commercially viable to be deployed at scale. MISO is actively engaged in tracking the progress of these technologies and is preparing to incorporate them into the system if/when the opportunity arises.

MISO does expect the commercial viability timelines of these technologies to be accelerated by the $370 billion in financial incentives for clean energy in the 2022 Inflation Reduction Act. In recognition of that, MISO modeled those incentives in the refreshed MISO Futures. More information on emerging technologies is available in MISO's 2022 Regional Resource Assessment.

LOAD ADDITIONS ARE SURGING



Some parts of the MISO region are enjoying a resurgence in manufacturing and/or other economic growth, with companies planning and building new factories, data centers and other energy-intensive facilities. For example, in the MISO South subregion that spans most of Arkansas, Louisiana, Mississippi and a small part of Texas, there are discussions and plans to build a variety of new manufacturing plants for steel, hydrogen, liquified natural gas and other heavy industry that could add more than 1,000 megawatts (MW) of new load. The tax credits for clean-energy manufacturing in the Inflation Reduction Act are helping to drive some of these additions.

While such development is welcome from an economic perspective, it can also pose significant grid reliability risks if the large load additions it spurs cannot be reliably served with existing or planned resources.

LOAD GROWTH DUE TO INCREMENTAL ELECTRIFICATION





While year-over-year demand for electricity in MISO has been fairly flat for many years, it is expected to increase going forward due to the electrification trends in other sectors of the economy. Electric vehicles are growing in popularity, and the residential and commercial building sectors are increasingly using electricity for heating and cooling purposes — with a desire to source this new electric load from renewables. These trends will likely accelerate even more due to the substantial financial incentives in the Inflation Reduction Act for electric vehicles, rooftop solar systems and electric appliances.

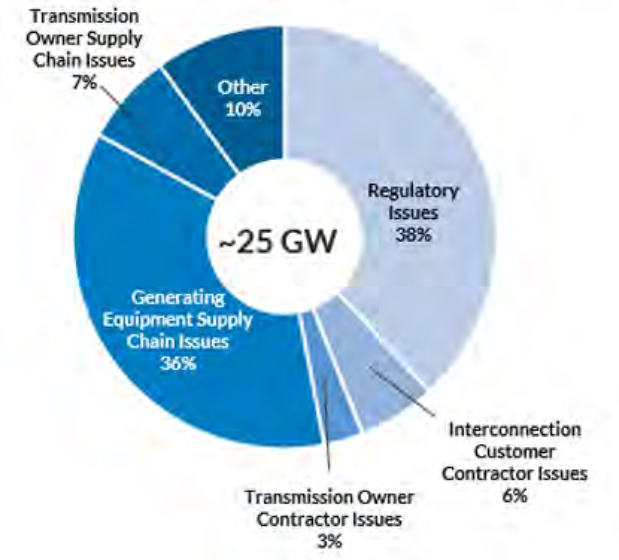
The impacts of these trends could be significant. In MISO's 2021 Electrification Insights report, MISO found that electrification could transform the region's grid from a summer-peaking to a winter-peaking system and that uncontrolled vehicle charging and daily heating and cooling load could result in two daily power peaks in nearly all months of the year.

DELAYS TO APPROVED GENERATION PROJECTS

In addition to reliability being challenged by declining accredited capacity, electrification and load additions, another concern is that a large number of fully approved and much-needed new generation projects are being delayed by supply chain issues, regulatory issues, and other external factors beyond MISO's control.

As of late 2023, about 25 GW of fully approved generation projects in MISO's Generator Interconnection Queue had missed their in-service deadlines by an average of 650 days, with developers citing supply chain and permitting issues as the two biggest reasons for the delays. An additional 25 GW of fully approved queue projects had not yet missed their in-service deadlines as of late 2023, but MISO expects many of them will also be delayed by external factors.

25 GW of fully approved & much-needed generation projects are delayed by supply chain and other issues



As the region's capacity picture continues to tighten, the possibility that upward of 50 GW of fully approved new generation projects could be delayed by external factors beyond MISO's control is deeply concerning.

FUEL ASSURANCE RISKS

The transition to a low- to no-carbon electric grid also poses risks in the realm of fuel assurance. These risks impact conventional coal and gas resources that provide reliability attributes such as system adequacy, flexibility and system stability that may be becoming scarce due to fleet change.

Coal resources have historically been considered fuel-assure because large stockpiles of fuel can be stored on-site. However, coal supplies have tightened in recent years due to a confluence of factors, including contraction of the mining and transportation sectors and supply chain issues. These factors increase the risk that coal plants will be unable to perform due to a lack of fuel availability. Coal resources can also be affected by extreme winter weather freezing onsite coal piles and/or impacting coal-handling equipment.

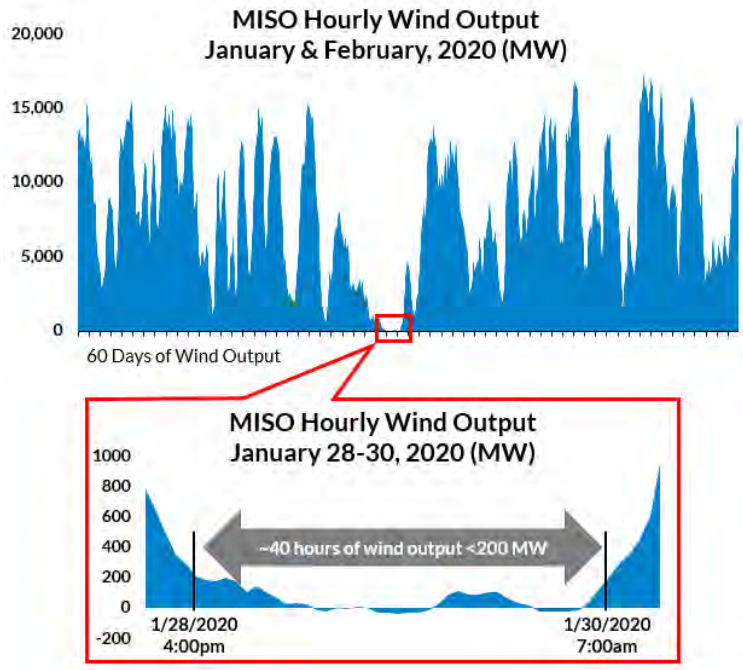
Gas-fired resources are also subject to fuel-assurance risks because they rely on pipelines to deliver gas to them. However, because the pipeline system was largely built for home-heating and manufacturing purposes, gas power plants sometimes face very challenging economic conditions to procure the fuel they need to operate. In the MISO region, this has historically occurred during extreme winter weather events that drive up home-heating needs for gas. Many gas generators in MISO do not have "firm" fuel-delivery

contracts, opting instead for less costly "interruptible" pipeline service or a blend thereof. Only about 27% of the gas generation that responded to MISO's 2023-2024 Generator Winterization Survey indicated it had firm transport contracts in place for all of their supplies during the 2023-2024 winter season. Additionally, gas power plants, gas pipelines and coal generators can be forced out of service by icing and other effects of severe winter weather — as has occurred in the MISO region and elsewhere with increasing frequency.

WIND DROUGHTS

Wind resources can experience "fuel" availability challenges in the form of highly variable wind speeds. Consequently, the energy output of wind can fluctuate significantly on a day-to-day and even an hour-by-hour basis — including multi-day periods when output drops far below average.

For example, over 60 consecutive days in January-February 2020, hourly wind output in MISO averaged more than 8,000 MW. However, as the chart shows, for 40 consecutive hours in the middle of that 60-day block, average hourly wind output dropped to less than 47 MW, and only once exceeded 200 MW in any single hour.



An even longer and broader "wind drought" occurred during Winter Storm Uri in 2021 when the MISO, Southwest Power Pool, Electric Reliability Council of Texas and PJM regions all experienced 12 consecutive days of low wind output.

Wind turbines can also be unavailable in extremely cold weather. While turbines equipped with special "cold weather packages" are designed to operate in temperatures as low as minus 22 F, they generally cut off if temperatures dip below that point. Still, it is important to keep in mind that all types of generators struggle in extreme cold, not just wind turbines.

EPA REGULATIONS COULD ACCELERATE RETIREMENTS OF DISPATCHABLE RESOURCES

While MISO is fuel- and technology-neutral, MISO does have a responsibility to inform state and federal regulations that could jeopardize electric reliability. In the view of MISO, several other grid operators, and numerous utilities and states, the U.S. Environmental Protection Agency (EPA) has issued a number of regulations that could threaten reliability in the MISO region and beyond.

In May 2023, for example, EPA proposed a rule to regulate carbon emissions from all existing coal plants, certain existing gas plants and all new gas plants. As proposed, the rule would require existing coal and gas resources to either retire by certain dates or else retrofit with costly, emerging technologies such as carbon-capture and storage (CCS) or co-firing with low-carbon hydrogen.

MISO and many other industry entities believe that while CCS and hydrogen co-firing technologies show promise, they are not yet viable at grid scale — and there are no assurances they will become available on EPA's optimistic timeline. If EPA's proposed rule drives coal and gas resources to retire before enough replacement capacity is built with the critical attributes the system needs, grid reliability will be compromised. The proposed rule may also have a chilling effect on attracting the capital investment needed to build new dispatchable resources.

RISKS IN NON-SUMMER SEASONS

In the past, resource adequacy planning in MISO focused on procuring sufficient resources to meet demand in the peak hour of the year, which normally occurs on a hot and humid summer day when air conditioning load is very high. If utilities had enough resources to reliably meet that one peak hour in the summer, the assumption was they could operate reliably for the other 8,759 hours of the year.

That assumption no longer holds true. Widespread retirements of dispatchable resources, lower reserve margins, more frequent and severe weather events and increased reliance on weather-dependent renewables and emergency-only resources have altered the region's historic risk profile, creating risks in non-summer months that rarely posed challenges in the past.

This changing risk profile is why MISO shifted from its annual summer-focused resource adequacy construct to a new framework that establishes resource adequacy requirements on a seasonal basis for four distinct seasons: summer (June-August); fall (September-November); winter (December-February); and spring (March-May). This new seasonal construct also seeks to ensure that resources will be available when they are needed most by aligning resource accreditation with availability during the highest risk periods in each season.









Pillar 1: Market Redefinition

MISO established the energy and ancillary service markets w nearly two decades ago when the composition of, and the risks to, the energy industry were very different from today. MISO's Markets of the Future report indicates that the region's foundational market constructs will continue to be effective going forward, but only with significant revisions. Further informed by the attributes analysis completed in 2023, MISO is enhancing and optimizing its market constructs and products to ensure they continue to deliver reliability and value in the face of fleet change, extreme weather events, electrification and load additions. This work occurs under four themes within the Market Redefinition pillar of the Reliability Imperative, as discussed below.

UNCERTAINTY AND VARIABILITY

In the planning horizon, MISO is addressing the changing risk profile and enhancing market signals for new resource investments. MISO's original resource adequacy construct was designed for a conventional fleet of resources where reliability risk was concentrated during the typical summer peak period. This is no longer the case. Factors such as aging conventional resources, more frequent and severe weather events and increased reliance on weather-dependent renewables have altered the region's historic risk profile, creating new risks in non-summer months and at differing times of the day. As the generation mix further diversifies, the accreditation process of evaluating each generator's contribution to the system is a critical reliability and planning mechanism.

In 2022, FERC approved MISO's proposal to shift from the annual, summer-based resource adequacy construct to a new construct with four seasons. The new seasonal construct also aligns the accreditation of thermal resources with availability in the highest-risk periods. These changes, implemented in the 2023-2024 Planning Resource Auction (PRA), are already delivering positive market outcomes, such as more proactive outage coordination among stakeholders and incentivizing improved unit performance.

MISO completed an evaluation of potential paths for non-thermal accreditation reforms 2022. This resulted in a proposed accreditation reform that leverages the principles from the thermal accreditation reform implemented in 2022, aligning the accreditation methodology for all resource types (except for emergency-only resources). MISO has proposed a transition period to begin applying the new accreditation methodology in the 2028-2029 planning year. The design work is expected to be finished with a filing with FERC in 2024.

The PRA was not designed to set higher capacity clearing prices as the magnitude of a shortfall increases. This lack of a "warning signal" can instill a false sense of calm among PRA participants, masking an imminent shortfall — as occurred with the 2022 PRA. MISO is working with its stakeholders to enhance pricing within the capacity construct by designing a Reliability-Based Demand Curve (RBDC) to better reflect MISO's market guiding principles, reliability risk and help avoid uneconomic retirements. Full implementation is planned for the 2025-2026 PRA, subject to FERC proceedings.

While the RBDC improves price signals in the planning horizon, MISO is also working on pricing reforms in the operating horizon. These focus on **scarcity pricing** when demand and reserve requirements exceed available supply in real time, often happening during extreme events when MISO enters emergency procedures to manage challenging conditions.

MISO's reforms to scarcity pricing will help incentivize appropriate market behavior, manage congestion throughout events and value reserve shortages appropriately, ultimately providing greater transparency and minimizing manual market intervention. MISO's focus areas for 2024 are updating the value of lost load, demand curves and forced-off assets that become physically disconnected from the grid due to weather-related transmission events. MISO has been presenting ideas at the Market Subcommittee stakeholder group. These enhancements will begin in 2024, with complete implementation expected by 2025.

Lastly, informed by the analysis of critical reliability attributes and in light of the changing reliability risk profiles in the region, MISO will work with stakeholders in 2024 to reevaluate the traditional risk metrics used in the industry for resource adequacy assessments and improve the underlying risk models.

RESOURCE MODELS AND CAPABILITIES

To avoid a looming shortage of necessary voltage stability attributes, as detailed in the *Attributes Roadmap*, MISO will advance a multistep technology standard to require capabilities from inverter-based resources to support grid stability at interconnection. In January 2023, MISO embarked on a path to improve inverter-based resource performance requirements using a reliability risk-based approach to evaluate potential gaps in MISO's current tariff. MISO finalized the proposed Tariff language in November to address the highest priority performance requirements and capabilities. This proposal is Phase 1 of the recommended four-phase approach, and this cross-matrix "resource models and capabilities" project will continue in the Interconnection Process Working Group (IPWG).

Another area of focus is MISO's work toward compliance with **FERC Order 2222**, which facilitates the participation of distributed energy resources (DERs) in wholesale electricity markets. DERs are small-scale resources such as rooftop solar panels, electric battery storage systems or electric vehicles and their charging equipment. In isolation, these resources would not have much impact on the grid, but when they are aggregated into a larger block, they can be impactful. MISO is developing a plan to comply with this order through broad collaboration with stakeholders, members, regulators, distributors and DER aggregators.

IDENTIFYING LOCATIONAL NEEDS

Another critical focus associated with increased uncertainty and variability is challenging reserve deliverability due to congestion. Historically, MISO utilized reserve zones to procure and reliably deliver reserves. MISO is working to implement improved locational granularity in its reserve products to ensure deliverability. Updating the reserve zones more frequently should enhance market efficiency and system reliability since there would be better alignment between zonal definitions and system conditions.

In addition to the local deliverability of resources, MISO will explore approaches to better hedge congestion through MISO's Auction Revenue Rights (ARR) mechanism and the Financial Transmission

Rights market. Evaluation has identified gaps and is exploring potential areas of improvement, including updating approaches for allocating ARRs, more granular periods, and ways to incentivize outages that better align with day-ahead energy models.

ENHANCING COORDINATION

As operational uncertainty and complexity increase, MISO continues to improve coordination across stakeholders and external entities, including neighboring grid operators. The collaborative **OMS-MISO Survey** provides a prompt view of resource adequacy over the five-year horizon, characterizing relative levels of resource certainty. MISO's **Regional Resource Assessment** (RRA) provides a collective 20-year view of the evolution of members' resource plans. It aims to provide insights that help members, states and MISO prepare for the energy transition. MISO's *Attributes Roadmap* specifically identifies the need for evolved coordination between MISO's resource adequacy assessments and MISO state and member planning process to ensure attribute sufficiency. MISO is committed to continued analysis, transparency and collaboration in the Resource Adequacy stakeholder forum.

One example is how transmission owners and MISO are working together on **ambient-adjusted ratings (AARs)** and **seasonal ratings** on transmission lines in the region, per the requirements of FERC Order 881. While using more accurate line ratings does not diminish the need to build new transmission, having the most accurate line rating information can help ensure that the region's transmission system is fully utilized and delivers its maximum value. MISO has engaged in extensive discussions with its transmission owners and consulted with other interested stakeholders to develop a compliance approach that meets the requirements of FERC Order 881 and is consistent with MISO's Tariff.

> "Our market products and the signals they send need to evolve and reflect the new realities and trends that we are experiencing. Input and support from our stakeholders will be key in the effective and timely implementation of these changes."
>
> Todd Ramey, MISO Senior Vice President, Markets and Digital Strategy

Pillar 2: Operations of the Future

MISO's control room operations are also challenged by fleet change, extreme weather and other risk drivers. In addition to implementing lessons learned from past events such as Winter Storm Elliott, forward-looking work is underway to ensure MISO has the capabilities, processes and technology to anticipate and respond to operational opportunities and challenges. This work, termed Operations of the Future, focuses on five buckets of work: (1) operations preparedness, (2) operations planning, (3) uncertainty and variability, (4) situational awareness and critical communications and (5) operational continuity.

OPERATIONS PREPAREDNESS

Tomorrow's control room will be very different from today. Operations preparedness is critical to managing the rapidly changing system conditions, increased volumes of data and enhanced technologies and tools that operators face. To ensure that control room personnel are ready to manage reliability effectively and efficiently in this new and continually evolving environment, MISO is developing improved operations simulation tools and enhancing operator training. In the future, operator and member training and drills will leverage a robust simulator that mirrors production and can quickly incorporate and maintain real-time event scenario simulations with broad, controlled access capabilities.

> "In the past, predicting load and generation was relatively straight-forward. In the future, the operating environment will be much more variable, and we need the people, processes and technology to deal with that variability."
>
> Jennifer Curran, MISO Senior Vice President, Planning & Operations and Chief Compliance Officer

OPERATIONS PLANNING

Operations planning helps MISO to remain a step ahead of the shifting energy landscape. System operators need to quickly access insights into the future and processes that enable the continued reliable and efficient operation of the bulk electric system. In the future, it will be necessary to leverage information in new ways. The ability to quickly model and analyze realistic planning scenarios will enable operators to develop and modify operating day plans from start to execution. Operators will be better prepared to manage increased uncertainty in resource availability with operational planning processes that are centralized and streamlined and outages that are proactively scheduled leveraging predictive economic impact analysis and power system studies.

UNCERTAINTY AND VARIABILITY

The increase in variable generation such as wind and solar has introduced greater uncertainty. Today, operators leverage a variety of market products and other analytics-based tools to manage uncertainty. To help manage increasing complexity, MISO is using machine-learning to predict net uncertainty for the upcoming operating day, using probabilistic forecasts and advanced analytics. With this more complete view, operators can create daily risk assessments that — when coupled with new dynamic reserve requirements — incentivize efficient unit-commitment decisions.

In the future, operators will need to manage the grid reliably and efficiently through tight margins, high-ramping periods, and increased variability by optimizing a risk management framework that accurately provides a risk profile based on net uncertainty impacts and by leveraging predictive economic impact analysis and power system studies.

SITUATIONAL AWARENESS AND CRITICAL COMMUNICATIONS

Situational awareness and critical communications will become even more important as operating risks become less predictable and more difficult to manage in day-to-day operations. New control room technologies and capabilities, improved real-time data capabilities and more complex operating conditions, driven by new load and generation patterns, will require MISO and its members to communicate even more quickly and efficiently.

Today, MISO operations rely heavily on the expertise of its operators. While operators have access to significant amounts of data related to weather, load and more, they must manually synthesize that data into useable information. Although this has worked well historically, solutions must envision a future with more complex information and operators who may not possess the same historical knowledge.

In the future, operators will need an integrated toolset that leverages artificial intelligence and machine learning, combined with additional data and analytics. Improvements in how MISO sees and navigates will give operators important information automatically. Systems will provide situational awareness insights for operators based on their function in the control room. Operators will analyze information and create new displays in real time to quickly assess the impacts of operational situations. Dynamic views of the state of the system will ensure operators can maintain the appropriate level of situational awareness while also reducing operator burden and automating key communication requirements, especially during critical events.

Additionally, enhancements to communications protocols, such as system declarations, will ensure that control rooms have the information they need when they need it. Automated messaging triggered by specific process and procedure actions will reinforce compliance with NERC standards.

OPERATIONAL CONTINUITY

Operational continuity capabilities need to evolve to align with the changing technologies, resource portfolio and threat landscape. Improved tools and updated processes are vital to ensuring that MISO can reliably operate the grid, mitigate risks, and, if necessary, recover quickly in the event of disruptions to toolsets or control centers.

Pillar 3: Transmission Evolution

The ongoing shift in the resource fleet and the substantial projected increase in load pose significant challenges to the design of the transmission system in the MISO region. MISO's Transmission Evolution work addresses these challenges in concert with other elements of the Reliability Imperative framework.

Under Transmission Evolution, MISO holistically assesses the region's future transmission needs while considering the allocation of transmission costs. This work creates an integrated transmission plan that reliably enables member goals while minimizing the total cost of the fleet transition, inclusive of transmission and generation. It also improves the transfer capability of the transmission system — meaning its ability to effectively and efficiently move energy from where it is generated to where it is needed.

LONG RANGE AND INTERREGIONAL TRANSMISSION PLANNING

Regional Long Range Transmission Planning (LRTP) and interregional planning are important parts of the Transmission Evolution pillar. The LRTP effort is developing four tranches of new backbone transmission to support MISO member plans for the changing fleet. In July 2022, the MISO Board of Directors approved LRTP Tranche 1. The 18-project portfolio of least-regret solutions is focused on MISO's Midwest subregion, representing $10.3 billion in investment. The projects in Tranche 1 will provide a wide range of value, including congestion and fuel savings, avoided capital costs of local resources, avoided transmission investments, resource adequacy savings, avoided risk of load shedding and decarbonization.

> "We see very little risk of over-building the transmission system; the real risk is in a scenario where we have underbuilt the system. Similarly, across markets and operations, our job is to be prepared."
>
> Clair Moeller, MISO President

This transmission investment hinges on appropriate allocation of the associated costs. MISO's Tariff stipulates a roughly commensurate "beneficiaries pay" requirement that must be met while balancing the divergent needs of MISO's three subregions. Because Tranches 1 and 2 primarily benefit the Midwest subregion, costs will only be allocated there. As Tranches 3 and 4 progress, other approaches may be considered based on stakeholder discussion. Work on Tranche 2 is progressing, with an anticipated approval by MISO's Board of Directors in 2024.

Futures refresh

MISO's future scenarios, or Futures, set the foundation for LRTP. The Futures help MISO hedge uncertainty by "bookending" a range of potential economic, policy and technological possibilities based on factors such as load growth, electrification, carbon policy, generator retirements, renewable energy levels, natural gas prices and generation capital cost over a 20-year period.

Member and state plans often do not provide resource information for the full 20-year study period covered by LRTP. Although MISO does not have authority over generation planning or resource procurement, this lack of information creates a gap in the resources needed to serve load and meet member goals. MISO fills the gap through resource expansion analysis, which seeks to find the optimal resource fleet that minimizes overall system cost while meeting reliability and policy requirements. The resulting resource expansion plans are used with their respective Future to identify transmission issues and solutions.

To lay the groundwork for Tranche 2 and to better understand potential future needs based on the most recent plans, legislation, policies and other factors, MISO refreshed its three Futures in 2023. While the defining characteristics of each Future remained the same (e.g., load forecast and retirement assumptions), updates were made to data and information that inform the potential resource mix. Among other factors, this includes state and member plans, capital costs, operating and fuel costs and defined resource additions and retirements. MISO also modeled the impacts of the clean energy tax credits in the federal Inflation Reduction Act because those incentives are expected to accelerate the transition to a decarbonized grid.

Future 2A, the focus of Tranche 2, indicates that fleet change will increase in velocity due to stronger renewable energy mandates, carbon reduction goals and other policies. Future 2A projects a 90% reduction in carbon emissions by 2042 and forecasts that wind and solar will provide 30% of the region's energy a full 10 years earlier than the previous Series 1 Futures that were used for Tranche 1.

Planning for an uncertain future

When planning for larger, regional solutions that address needs 20 years into the future, there is inherent uncertainty, which is why LRTP is designed to identify "least-regrets" transmission solutions. Appropriately managing this uncertainty is a key function of planning. In developing Future 2A, MISO leveraged the consensus on policy goals among MISO members and states about how quickly change would occur. Additionally, MISO's comprehensive processes and robustness testing demonstrate the benefits and needs of transmission solutions that achieve member goals and minimize costs, including several iterations of analyses for Future 2A and other scenarios.

Other visibility tools

As the system becomes more interdependent and interconnected, MISO provides information to members about the outcomes and impacts of their individual plans when studied in the aggregate. Anticipating and communicating changing risks and future systems needs within the planning horizon is critical to ensure continued reliability.

As described earlier in this report, the **OMS-MISO Survey** compiles information about new resources that utilities and states plan to build and older assets they intend to retire in the coming years. While this tool looks several years ahead, certainty is lower in later years when many significant risks will need to be addressed.

Because utility and state plans can be less specific and certain, cover a shorter timeframe and are not always publicly available, MISO conducts the **Regional Resource Assessment (RRA)** to capture more information and details. The RRA aggregates utility and state plans and goals — both public and private —

over a 20-year planning horizon to shed light on regional fleet evolution trends and timing. The information is then used to model potential reliability needs and gaps that may arise and may be leveraged to inform and advance analysis of resource attributes. In the future, new tools will provide stakeholders with ongoing access to RRA information for greater visibility into the impact of these future system changes.

Interregional initiatives

MISO continually works with its neighboring grid operators, Southwest Power Pool (SPP) and PJM, to address issues on the seams. Joint, coordinated, system plan studies are regularly conducted to assess reliability, economic and/or public policy issues. The studies can be more targeted in scope with a shorter study cycle or can be more complex, requiring a longer study period.



The Joint Targeted Interconnection Queue (JTIQ) initiative with SPP is an example of a recent complex study initiative. This unprecedented, coordinated effort identified a portfolio of proposed transmission projects that align with both MISO's and SPP's interconnection processes. These projects will create additional transmission capability to enable generator interconnections in both regions.

In October 2023, the U.S. Department of Energy (DOE) announced it would award $464.5 million in federal funding under the Grid Resilience and Innovation Partnerships (GRIP) program to the JTIQ portfolio. This historic opportunity significantly reduces the estimated investment for new transmission lines that will benefit seven states. A FERC filing to obtain approval of cost allocation for the JTIQ portfolio will be submitted in early 2024, and MISO Board approval will be sought thereafter. The process SPP and MISO followed to coordinate the study proved to be effective and significantly more efficient than typical Affected System Studies. Based on its success, the process will be included in the 2024 filing to enable improved coordination in the future.

PLANNING TRANSFORMATION

MISO's planning tools and processes must also evolve as the transitioning resource mix increases the complexity of transmission planning. In response, Planning Transformation, another component of the Transmission Evolution pillar, will develop aligned, adaptable and flexible processes and tools over the next five to 10 years to recognize and address emerging transmission threats and risks identified in markets and operations.

The new MISO Transmission Expansion Plan (MTEP) Portal is a major step in this transformation. The system launched in October 2023 and helps MISO staff and transmission owners manage project data more efficiently and effectively, and it will save hundreds of work hours each year. It also provides stakeholders better support for submitting, updating, tracking and managing MTEP projects and enables more transparency.

Other measures — such as the Generator Interconnection Portal and technology evaluation of resource siting — are already implemented, underway or planned for the future. These include evolving technology

for the resource transition, adapting planning criteria to enhance system resiliency and robustness, and integrating model data.

RESOURCE UTILIZATION

The Resource Utilization initiative focuses on improving resource utilization planning to include a dynamic generator retirement process, more rapid generator interconnections and resource reliability attributes that are addressed throughout the resource lifecycle.

To improve the generator retirement process, asset owners are now required to provide one-year advance notice of resource retirements, an increase from the prior 26 weeks. Quarterly retirement studies have also been instituted to better forecast the engineering workload needed to conduct analyses, and other changes are being implemented that help align retirements with MTEP processes and improve visibility of retirements to stakeholders.

MISO is also working to ensure its processes do not impede generator interconnections. Although MISO's queue processes have been effective in cycles with typical volumes, they are not sufficient for managing recent request volumes that are growing exponentially compared to historical norms. This significantly increases the time it takes MISO to complete studies, which drives more project withdrawals, provides less certainty of early study results, and, ultimately, complicates late-stage studies. These issues are compounded by many speculative projects, despite years of reforms on "first ready, first served" principles.

Improvements to customer-facing and backend operational queue processes over the past several years have enabled more efficient application processing. However, additional changes are needed to manage the dramatic growth in applications, further expedite the interconnection process and maximize transparency and certainty to customers.

As a result, MISO paused accepting interconnection applications for the 2023 cycle, with plans to resume in March 2024 after receiving FERC approval on multiple process improvements to ensure better interconnection requests are submitted. The 2024 cycle is anticipated to begin in the fall of 2024, as it has in previous years.

Tariff changes approved by FERC in January 2024 increase financial commitments and withdrawal penalties and require interconnection customers to provide greater site control for projects. FERC did deny a MISO proposal to cap the size of queue study cycles to ensure they do not exceed a certain percentage of MISO load. However, FERC provided guidance on how MISO could implement a cap in the future, as well as other improvements that will enable the dispatch of existing resources with new interconnection requests. MISO believes these changes will decrease applications and result in higher-quality, more viable projects entering the queue. A reduction in project withdrawals may ultimately reduce network upgrades between studies and provide greater planning certainty for customers and MISO.

In July 2023, FERC issued Order 2023 to ensure that generator interconnection customers can interconnect to the transmission system in a reliable, efficient, transparent, timely and nondiscriminatory manner. The order is mostly consistent with the queue changes MISO has already implemented and

intends to implement going forward. MISO is reviewing the order to assess potential changes and compliance needs.

Lastly, as described in the Resource Models And Capabilities section of this report, MISO is advancing a multistep technology standard to require capabilities from inverter-based resources to support grid stability through the Interconnection Process Working Group. This cross-matrix work is further described in MISO's *Attributes Roadmap* report as a solution to mitigate the potential shortage of system stability attributes.

Delays outside of MISO's control

Despite improvements MISO has made to its Generator Interconnection Queue, many fully approved projects are not going into service on schedule due to supply chain issues and permitting delays that are beyond MISO's control. As of late 2023, about 25 gigawatts (GW) of resources that were fully approved through MISO's queue process had missed their in-service deadlines by an average of 650 days, with developers citing supply chain and permitting issues as the two biggest reasons for the delays. An additional 25 GW of fully approved queue projects had not yet missed their in-service deadlines as of late 2023, but MISO expects many of them will also be delayed by external factors.









Pillar 4: System Enhancements

Continual system enhancements and modeling refinements are the bedrock of MISO's response to the Reliability Imperative. The ongoing complexities of the electric industry landscape necessitate paramount upgrades to facilitate reliability-driven market improvements. The Market System Enhancement (MSE) program stands out as a visionary endeavor, focusing on upgrading, building and launching new systems with improved performance, security and architectural modularity. This strategic emphasis enhances MISO's capability to respond swiftly and efficiently and deliver new market products that align with the evolving industry landscape.

MISO places strategic importance on enabling a mature hybrid cloud capability to future-proof the technological infrastructure and foster a resilient and adaptable organizational framework. Simultaneously, the commitment to fostering a flexible work environment amplifies MISO's readiness for ongoing technological changes. This dynamic approach, centered on securely harnessing hybrid cloud technology, optimizes the work environment, positioning MISO for future advancements. The integration of these strategies underlines MISO's forward-looking approach and establishes its leadership in embracing advanced technologies for safeguarding operations.

MARKET SYSTEM ENHANCEMENT (MSE) PROGRAM

The MSE program, initiated in 2017, is a transformative force in reshaping MISO's market platform. Its focus on creating a more flexible, upgradeable and secure system underscores its pivotal role in accommodating the region's evolving portfolio and technology changes. The achievements in 2023 highlight the program's commitment to continuous improvement. The upgrade of the Energy Management System, completion of Phase 2 Core Development, and advancements in the Day-Ahead Market Clearing Engine and Real-Time Market Clearing Engine showcase MSE's impact on improving functionality, user experience, business continuity and security posture. This program is not merely a technological upgrade; it is a strategic initiative that positions MISO to meet the demands of the future electric grid.

> "For MISO to continue to deliver on our mission, we must prioritize our plan to address the right strategic drivers that will enable us to accommodate the region's evolving portfolio and technology changes. The work we do in System Enhancements supports the transformational efforts across the Reliability Imperative and will increase value to our stakeholders."
>
> Todd Ramey, Senior Vice President, Markets and Digital Strategy

WORK ANYWHERE

MISO's strategic move toward future-proofing its technological infrastructure involves enabling and maturing hybrid cloud capabilities. This initiative goes beyond technology; it embraces the transformative strategy of realizing a flexible work environment that transcends conventional boundaries. The delicate balance between the freedom to work remotely and stringent adherence to security and compliance requirements signifies a definitive change in how MISO approaches work. This shift sets the stage for a more agile and responsive workforce, enhancing productivity and embracing the evolving nature of work. Simultaneously, adopting a well-managed hybrid cloud platform forms the backbone of MISO's technological evolution, allowing seamless operations between on-premises data centers and the public cloud. This combination fortifies organizational resilience and propels MISO into a future where adaptability is the key to sustainable success.

SECURITY OF THE FUTURE

MISO's commitment to seamlessly integrating cutting-edge technologies is underpinned by a dedication to security, reliability and efficiency. This includes initiatives designed to fortify MISO's approach to cybersecurity. Refining identity and access management practices, adopting a proactive zero-trust approach and transforming asset management data quality and timeliness demonstrate MISO's proactive stance against the evolving cyber threat landscape. The commitment extends beyond external threats to assessing security best practices for the internal environment. The ongoing thorough review to evaluate and implement the latest security protocols, conduct regular audits and stay abreast of emerging threats exemplifies MISO's dedication to securing tomorrow.

DATA AND ANALYTICS

MISO's data strategy is a comprehensive framework that goes beyond a simple upgrade — it is a visionary approach to enhancing MISO's data capabilities. The three key priorities — fostering an enterprise culture, delivering a holistic process framework and providing a curated environment — fortify MISO's position as a leader in the energy sector. This strategy modernizes tools, platforms, technologies and processes and empowers teams to model, simulate, analyze and visualize data for informed decision-making. Through a focused and well-defined program, MISO is set to realize a data platform that not only meets the needs of today but is agile enough to adapt to the evolving landscape of data requirements.

MISO Roadmap

As illustrated below, the **MISO Roadmap** outlines MISO's priorities to help its members to reliably achieve their plans and goals. The MISO Roadmap resides on MISO's public website.



MISO's Role

This report is written from MISO's perspective. However, the responsibility for ensuring grid reliability and resource adequacy in the MISO region is not MISO's alone. It is shared among Load Serving Entities (LSEs), states and MISO, each of which have designated roles to play.

LSEs are utilities, electric cooperatives and other types of entities that are responsible for providing power to end-use customers. In most (though not all) of the MISO region, LSEs have designated service territories and are regulated by state agencies. LSEs have exclusive authority to plan and build new generation resources and to make decisions about retiring existing resources, with oversight from state agencies as applicable by jurisdiction.

MISO performs certain transmission planning functions but does not plan or build new generation or decide which existing resources should retire. MISO exercises functional control of its members' generation and transmission assets with the consent of its members and per the provisions of its Tariff, which is subject to approval by FERC. By operating these assets as efficiently as possible on a region-wide basis, MISO generates substantial cost savings and other reliability benefits that would not otherwise be realized.

MISO also establishes and administers resource adequacy requirements for LSEs and states, as applicable by jurisdiction. These include:

- A **Planning Reserve Margin (PRM)** that sets the level of contractually obligated resources that MISO can call into service when normally scheduled resources go offline for planned or unplanned reasons or when demand surges due to extreme weather conditions or other factors. The PRM is set through MISO's stakeholder process.
- A **Planning Resource Auction (PRA)** that LSEs can use to procure needed resources or sell surplus resources. LSEs can "opt out" of the PRA by using their own resources or negotiating bilateral contracts with other entities.
- **Resource accreditation metrics** that determine how much "credit" various types of resources receive toward meeting resource adequacy requirements based on factors such as their unplanned outage rates.
- **Locational procedures** that determine how much capacity is needed in certain parts of the MISO region for reliability purposes and how much can be imported from and exported to other locations, among other things.

MISO engages with a broad range of stakeholders to share ideas and discuss potential solutions to the challenges facing the region. The Reliability Imperative work also involves a robust, collaborative dialogue across the many forums within the stakeholder process. The collaboration that takes place in these forums has provided valuable policy and technical-related feedback, and MISO is committed to continuing that engagement.

MISO INITIATIVES ARE INTERCONNECTED AND SEQUENCED

MISO's strategic priorities are connected and build upon each other. Success in one area depends on progress in another, so efforts must be coordinated and sequenced. For example, achieving reliable and economically efficient grid operations requires new tools and processes to be developed under the Operations of the Future workstream and market enhancements to be developed under the Market Redefinition workstream.

Given the urgent and complex challenges that are facing the region, it is crucial for MISO members, states and MISO to work together to execute on the reforms that are needed.

The MISO Value Proposition

MISO creates substantial cost savings and other benefits by managing the grid system on a regional basis that spans all or parts of 15 states and one Canadian province. Before MISO was created, the system was managed by 39 separate Local Balancing Authorities (LBAs), which made the grid much more fragmented and far less economically efficient than it is today.

The benefits that MISO created in calendar year 2022 range from $3.3 billion to $4.5 billion, according to the Value Proposition study that MISO performs every year. That represents a benefit-to-cost ratio of about 12:1 when compared to the fees that utilities pay to be members of MISO. MISO creates benefits in a variety of ways, including through efficient dispatch and reduced need for assets. Since the Value Proposition study was launched in 2007, the cumulative benefits that MISO has created exceed $40 billion. And notably, that figure does not reflect all the benefits MISO creates due to the conservative approach that MISO uses to conduct the study.

While continuing to use this conservative approach, MISO anticipates that it will create even more benefits going forward by helping its members and states to achieve their decarbonization goals in a reliable manner. In June 2022, MISO looked at those anticipated future benefits in a supplemental report called the Forward View of the Value Proposition. That report estimates the value that MISO will create going forward in two ways that are not specifically reflected in the "standard" Value Proposition study: (1) the value of sharing carbon-free energy from areas with higher levels of renewables to regions with lower levels, and (2) the value of sharing flexibility attributes that are required to integrate those new renewables while maintaining reliability.

MISO found that by including these two additional value streams, MISO's total benefit-to-cost ratio would increase from approximately 12:1 today to approximately 26:1 by 2040. This illustrates that while there are indeed many challenges associated with fleet change, there are also tremendous economic benefits that utilities and states can realize by pursuing their decarbonization goals as members of MISO.

Informing the Reliability Imperative

MISO's response to the Reliability Imperative has been informed by years of conversations with stakeholders. MISO has also undertaken numerous studies to assess the region's changing risk profile and to explore how reliability is being affected by various drivers. This work includes:



Attributes Roadmap: This study looks at three key electric system attributes where near-term risk is most acute: (1) System Adequacy, (2) Flexibility and (3) System Stability. The Attributes Roadmap recommends advancing a combination of current and new proposals as well as providing ongoing attributes visibility through regular reporting.



Renewable Integration Impact Assessment (RIIA): This study assesses the impacts of integrating increasingly higher levels of renewables into the MISO system. RIIA indicates that planning and operating the grid will become significantly more complex when greater than 30% of load is served by wind and solar. However, RIIA also indicates that renewable penetrations of greater than 50% could be reliably achieved if utilities, states, and MISO coordinate closely on needed actions.



Regional Resource Assessment (RRA): The RRA is a recurring study based on the plans and goals MISO members have publicly announced for their generation resources. The RRA aggregates these plans and goals to develop an indicative view of how the region's resource mix might evolve to meet utilities' stated objectives. The RRA aims to help utilities and states identify new and shifting risks years before they materialize, creating a window to develop cost-effective solutions.



MISO Futures: The MISO Futures utilize a range of economic, policy and technological inputs to develop three future scenarios that "bookend" what the region's resource mix might look like in 20 years. The Futures inform the development of transmission plans and help MISO prioritize work under the Reliability Imperative. Series 1 was published in 2021. In 2023, MISO updated the report to Series 1A to reflect evolving member/state plans and the clean energy incentives in the Inflation Reduction Act, among other things.



Markets of the Future: This report illustrates how and when MISO's market structures will need to evolve in order to accommodate the transformation of the energy sector. The needs are presented in four broad categories: (1) Uncertainty and Variability, (2) Resource Models and Capabilities, (3) Location and (4) Coordination. This report helped establish the foundation for the work MISO is currently doing to identify critical system attributes.



The February (2021) Arctic Event: This report discusses lessons learned from Winter Storm Uri, which affected the MISO region and other parts of the country in February 2021. MISO and its members took emergency actions during the event to prevent more widespread grid failures. Uri illustrated how extreme weather can exacerbate the challenges of fleet change. Preparing for extreme weather is a major part of MISO's response to the Reliability Imperative.



Electrification Insights: This report explores the challenges and opportunities the grid could face from the growth of electric vehicles and the increasing electrification of other sectors of the economy, such as homes and businesses. The report indicates electrification could transform the MISO grid from a summer-peaking to a winter-peaking system, and that vehicle charging and daily heating and cooling load could result in two daily power peaks nearly all year.

From this groundwork, we know there are many challenges ahead. But we also believe we can respond to the Reliability Imperative in a manner that enables our members to achieve their resource plans and policy objectives. We are determined to do the hard work required to ensure our members benefit from MISO membership.

Acronyms Used in This Report

DER: Distributed Energy Resource

FERC: Federal Energy Regulatory Commission

GW: Gigawatt

JTIQ: Joint Targeted Interconnection Queue

LBA: Load Balancing Authority

LSE: Load Serving Entity

LRTP: Long Range Transmission Planning

MSC: Market Subcommittee

MISO: Midcontinent Independent System Operator

MSE: Market System Enhancement

MTEP: MISO Transmission Expansion Plan

MW: Megawatt

NERC: North American Electric Reliability Corporation

OMS: Organization of MISO States

PAC: Planning Advisory Committee

PRA: Planning Resource Auction

PRM: Planning Reserve Margin

RBDC: Reliability-Based Demand Curve

RIIA: Renewable Integration Impact Assessment

RRA: Regional Resource Assessment

SPP: Southwest Power Pool

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BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

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

Exhibit 88
Schahfer Waste Disposal Area Closure Plan

NIPSCO LLC R. M. Schahfer Generating Station
Waste Disposal Area Closure Plan - Version #5

Northern Indiana Public Service Company LLC
Rollin M. Schahfer Generating Station
Wheatfield, Indiana

Submitted to:

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October 2020



Certification

Professional Engineer Certification Statement [40 CFR 257.102(b)(4)]

I hereby certify that, having reviewed the attached documentation and being familiar with the provisions of Title 40 of the Code of Federal Regulations Section 257.102 (40 CFR Part 257.102), I attest that this Closure Plan is accurate and has been prepared in accordance with good engineering practices, including the consideration of applicable industry standards, and with the requirements of 40 CFR Part 257.102.

Golder Associates Inc.

Signature

October 28, 2020
Date of Report Certification



Richard Wesenberg
Name

PE11500584
Professional Engineer Certification Number

Table of Contents

1.0 INTRODUCTION 1

2.0 CLOSURE PLAN CONTENT [40 CFR §257.102(b)(1)] 1

2.1 Narrative Description [40 CFR §257.102(b)(1)(i-ii)] 1

2.2 WDA Quantity and Area [40 CFR §257.102(b)(1)(iv,v)] 2

2.3 CCR Removal and Unit Decontamination [40 CFR §257.102(b)(1)(ii)] 2

3.0 SCHEDULE [40 CFR §257.102(b)(1)(vi)] 3

3.1 Introduction 3

3.2 Closure Construction 3

3.2.1 Permitting/Engineering/Procurement 3

3.2.2 Dewatering Activities 3

3.2.3 CCR Excavation 4

3.2.4 Soil Backfill / Site Stabilization 4

4.0 CLOSURE PLAN AMENDMENTS 5

5.0 REFERENCES 6

TABLES

Table 3.2: WDA CCR Removal Schedule Milestones
Table 4.1: WDA Closure Plan Amendment Log

FIGURES

Figure 1 – Site Location Map
Figure 2 – Existing Conditions Plan
Figure 3 – Proposed CCR Excavation Grades
Figure 4 – Proposed Backfill Grades
Figure 5 – Cross Sections
Figure 6 – WDA CCR Closure by Removal Schedule

1.0 INTRODUCTION

Northern Indiana Public Service Company LLC (NIPSCO LLC, the owner/operator) maintains and operates the Waste Disposal Area (WDA), an active unlined CCR surface impoundment (the CCR Unit) at its R. M. Schahfer Generating Station, 2723 East 1500 North, Wheatfield, Jasper County, Indiana (RMSGS, Site). See Figure 1 – Site Location Map and Figure 2 – Existing Conditions Plan.

The WDA, located in the southwest area of RMSGS station operations, is formed by an approximately 17-foot high perimeter earth-fill dike with slurry trench core that encloses an area of approximately 80 acres. The WDA receives both CCR (historically bottom ash/boiler slag and sluice water as the predominant CCR influents and, beginning only recently, an FGD stream) and non-CCR waste streams from the generating station. All flow to the WDA is pumped through primarily subsurface lines which daylight and discharge directly into the northern end of the CCR Unit. As determined by bathymetric surveys and overwater drilling programs, most of the deposited ash/slag is in the northern one-third to one-half of the WDA. Due to the size of the unit, percentage of solids to liquids in the influent, location of ash discharge outfalls, and settling/depositional properties of the materials, preliminary studies have shown little ash/slag is present in the southern half of the WDA. Based on these characteristics of the WDA and the potential for future beneficial reuse applications of content CCR, which would remove bottom ash inventory from the impoundment, NIPSCO LLC will pursue a closure by removal from the CCR Unit pursuant to 40 CFR §257.10.This written closure plan, prepared in accordance with the requirements of 40 CFR §257.102(b), describes the steps necessary to close the WDA consistent with recognized and generally accepted good engineering practices.

2.0 CLOSURE PLAN CONTENT [40 CFR §257.102(b)(1)]

This closure plan complies with 40 CFR §257.102(b)(1), which outlines the content required in the written closure plan for CCR units including the information specified in 40 CFR §§257.102(b)(1)(i), (b)(1)(ii), (b)(1)(iv), and (b)(1)(vi) when closing by removal of CCR. The following sections provide a narrative of how the CCR Unit will be closed including procedures, estimated quantities of material management, and schedule of activities and associated durations.

2.1 Narrative Description [40 CFR §257.102(b)(1)(i-ii)]

The WDA will be closed by removing and decontaminating all areas affected by releases from the CCR Unit. For the purposes of this closure plan, removal addresses a) the CCR inventory, and b) affected soils in the perimeter embankments and/or the floor of the impoundment that were in direct contact with the CCR. Removal will be performed during the closure construction activities and certified complete by no later than October 17, 2028.

Decontamination relates to groundwater impacts, if any, above the CCR Unit-specific groundwater protection standards (GWPS). Groundwater decontamination will be achieved and demonstrated following completion of CCR removal activities by one or more of the following: post-closure monitoring, monitored natural attenuation, or other passive (e.g., permeable reactive barrier [PRB]) or active (e.g., groundwater extraction and treatment) methods as deemed appropriate following removal activities and stabilization of the groundwater regime. Post-closure groundwater decontamination and monitoring will be conducted after the 2028 WDA closure certification.

WDA CCR removal and decontamination will be complete when constituent concentrations throughout the CCR Unit and any areas affected by releases from the CCR Unit have been removed and groundwater monitoring concentrations do not exceed the GWPS established pursuant to 40 CFR 257.95(h).

Prior to removal of CCR, discharge of influent waste streams into the WDA will cease and/or be redirected, pipelines will be properly abandoned and associated infrastructure removed as necessary, and the CCR unit will be dewatered by means of gravity discharge and actively pumping surficial and interstitial water downstream (conveyed through the Recycle Basin and Final Settling Basin and ultimately discharged into the Kankakee River) in a manner that maintains National Pollutant Discharge Elimination System (NPDES) permitted effluent limits.

Once the WDA is dewatered and hydraulic structures are abandoned, the remaining CCR and all areas affected by releases from the CCR Unit (i.e., perimeter embankment or underlying soils in direct contact with impoundment CCR contents) will be removed. Anticipated CCR depths were determined by historic Sargent and Lundy drawings and an assessment of CCR depths performed by Golder Associates Inc. (Golder) in summer 2019. Based on the available information, the WDA excavation design extends to a bottom elevation of approximately 663.0' NAD83 as provided in Figure 3 – Proposed CCR Excavation Grades and Figure 5 – WDA Cross Sections. A detailed description and estimated schedule for the dewatering and CCR removal activities are provided in Section 3.

Construction Quality Assurance, including but not limited to, photographic documentation will be conducted in the field during closure construction activities to provide evidence documenting CCR removal. This and related information about construction contractor activities will support the qualified Indiana-licensed professional engineer's certification of closure, to be completed by no later than October 17, 2028. Satisfactory decontamination of any groundwater affected by releases from the CCR Unit will be confirmed when at least two consecutive quarterly groundwater monitoring events demonstrate that groundwater monitoring concentrations do not exceed the GWPS established pursuant to 40 CFR 257.95(h).

2.2 WDA Quantity and Area [40 CFR §257.102(b)(1)(iv,v)]

Golder performed an investigation between July and November 2019 of the relative placement/location and volume of CCR materials in the WDA. Through visual observation of gridded random and supplemental focused core samples, the investigation sampling determined CCR extended to depths that ranged from 0.5 to 20 feet, corresponding to elevations of approximately 653 to 665 (NAVD88) (Golder 2020). In 2017, DLZ Industrial, LLC, on the behalf of NIPSCO LLC, completed a survey mapping the top of CCR deposition topography. The maximum CCR inventory was estimated with AutoCAD Civil 3D by comparing the current surface of the WDA (estimated top of CCR deposition) to the investigation-derived estimated bottom of CCR material surface provided in Figure 3 - Proposed CCR Excavation Grades. Based on this comparison, the estimated maximum documented inventory of CCR in the 80-acre WDA was approximately 1 million cubic yards.

2.3 CCR Removal and Unit Decontamination [40 CFR §257.102(b)(1)(ii)]

Per 40 CFR 257.102(b)(1)(ii), if closure of the WDA will be accomplished through removal of CCR from the CCR Unit, a description of the procedures to remove the CCR and decontaminate the CCR Unit in accordance with this section must be provided in the closure plan. Per 40 CFR §257.102(c), CCR removal and decontamination of the CCR Unit are complete when constituent concentrations throughout the CCR Unit and any areas affected by releases from the CCR unit have been removed, and groundwater monitoring concentrations do not exceed the groundwater protection standard established pursuant to 40 CFR §257.95(h) for constituents listed in Table 2.1.1. The following description includes the procedures to remove and decontaminate the WDA.

The WDA will be dewatered, its hydraulic structures will be abandoned, and CCR will be removed. It is anticipated that the excavation will extend to elevation 663.0 NAD83. Proposed conceptual excavation limits with approximate elevations are provided in Figures 3 and 5. Photographic documentation will be conducted in the

field during closure to provide evidence documenting CCR removal. Further details on construction methods and timelines are provided in Section 3.2.

Groundwater monitoring will be conducted to document that constituent concentrations throughout the CCR unit and any areas affected by releases from the CCR unit do not exceed the groundwater protection standards per 40 CFR 257.95(h) for constituents listed in Table 2.1.1. Closure will be complete when two consecutive quarterly groundwater monitoring events demonstrate no exceedances.

3.0 SCHEDULE [40 CFR §257.102(b)(1)(vi)]

3.1 Introduction

NIPSCO LLC will initiate closure of the WDA by providing notification pursuant to 40 CFR §257.102(g) when CCR placement is expected to cease and at least one of the following actions or activities have been completed:

- Steps taken to implement the written closure plan
- Completed application submitted for any required state or agency permit or permit modification
- Necessary steps taken to comply with any state or other agency standards that are a prerequisite, or are otherwise applicable, to initiating or completing the closure of a CCR unit

Closure construction activities are anticipated to commence by September 15, 2025 and expected to be completed within approximately three years of the notification of intent to initiate closure (by August 17, 2028).

3.2 Closure Construction

NIPSCO LLC anticipates the WDA will cease receipt of CCR and non-CCR waste streams by August 31, 2025 and initiation of closure activities will commence no later than 30 days after final receipt waste. The principal components to complete the WDA closure by removal project include permitting/engineering/procurement, dewatering, CCR excavation and soil backfill as further detailed in the following sections.

3.2.1 Permitting/Engineering/Procurement

Prior to the scheduled final cessation of influent discharge into the WDA, NIPSCO LLC will develop construction plans and specifications for the closure by removal project. In accordance with current State of Indiana CCR surface impoundment closure procedures, these plans will be reviewed and approved by the Indiana Department of Environmental Management (IDEM) prior to NIPSCO LLC initiating closure activities. A temporary or modified NPDES permit for dewatering activities may also be required and will be secured by NIPSCO LLC, if necessary. A duration of six months was assumed for the construction plan development, twelve months for IDEM review and approval of construction plans, four months for the NPDES Permit (if necessary), and three months for contractor selection and procurement. Based on its previous experience conducting CCR surface impoundment closures, NIPSCO LLC believes these are reasonable timeframes for this aspect of the WDA closure process.

3.2.2 Dewatering Activities

Following the cessation and/or redirect of all waste streams out of the WDA and in accordance with applicable NPDES permit requirements, NIPSCO LLC will initiate dewatering activities. Phase 1 of the dewatering activities will involve gravity drainage through the existing overflow weir (drop-inlet structure) into the Recycle Basin. Discharge from the Recycle Basin is pumped via eight existing submersible pumps with a total capacity of 30,000 gallons per minute (gpm) and conveyed to the Final Settling Basin. The surficial water volume is conservatively

estimated to be approximately 263 million gallons (MG, water surface elevation of 669.0' NAD83). The maximum flow through the 36-inch diameter overflow pipe from the WDA into the Recycle Basin is approximately 52 cubic feet per second (cfs) or 23,000 gpm. Therefore, it is estimated that with continuous discharge and full-time pumping operations the surficial water could be removed from the WDA within 8-days. However, to allow for a gradual drawdown of the water, accommodate possible pump repair and maintenance needs, account for precipitation during the surficial dewatering period, and realize passive dewatering of the interstitial water within the CCR deposition, a 90-day period for surficial water removal has been applied to the schedule.

Dewatering of interstitial water and ongoing precipitation will commence following completion of the removal of the surficial water and in conjunction with CCR excavation. Given the WDA is surrounded by a slurry wall, negligible inflow from groundwater is expected. It is anticipated that interstitial water will be removed to an elevation of 2-ft below the bottom of excavation providing a relatively dry, stable floor to complete CCR removal and associated closure verification activities. An interstitial water volume of approximately 206MG with an additional 90MG of precipitation (based on average annual precipitation) is expected to be managed and removed during CCR excavation activities. Actual dewatering means and methods will be determined by the contractor including but not limited to well points and/or internal sump and trenching techniques. A conservative dewatering rate of at least two dewatering systems operating at a rate of 400 gpm (800 gpm total) was used to estimate a twelve month duration for interstitial and precipitation dewatering activities.

3.2.3 CCR Excavation

CCR excavation will be accomplished primarily though mechanical means by excavators, low ground pressure (LGP) dozers and off-road haul trucks. Excavated CCR will be transported to the onsite RMSGS IDEM permitted Landfill located approximately 1.5 miles from the WDA. An excavation rate of 5,000 cubic yards per day (CYD/day) was applied to the schedule and is an appropriate excavation rate assuming at least two excavators and dozers and approximately 10 off-road haul trucks. A 30-cubic yard capacity off-road truck equates to approximately 17 round trips per truck per day to the landfill located 1.5-miles from the WDA. Removal of the estimated 1M CYD of CCR at a rate of 5,000 CYD/day and assuming 5-day work weeks, equates to a duration of ten months for CCR excavation. Given all excavation activities occur within the Site, no seasonal downtime was assumed due to local frost laws on public highways. If necessary, additional means and methods may be employed to adjust the schedule and/or duration of excavation activities, such as increased equipment support and increased work-week and/or work-day schedules.

3.2.4 Soil Backfill / Site Stabilization

Once the CCR has been removed from the WDA, soil backfill will be imported from a local borrow source to efficiently shed stormwater from the closed configuration of the WDA as provided in Figure 4 – Backfill Grading Plan. Approximately 1.6M CYD of soil backfill and 70,000 CYD of topsoil will be required. It should be noted that the 1.6M CYD soil backfill volume assumes that all soil will be imported from an off-site borrow source and that un-impacted berm material outside the slurry wall will not be replaced as soil backfill. NIPSCO LLC may, at a later date, determine that the existing berm material (included in the CCR excavation estimate in Section 2.2) is suitable for soil backfill to reduce the off-site soil backfill volume. In addition, advancement of the closure design may yield other suitable closed configurations resulting in a reduction of required import material.

It is reasonable to apply a placement rate of 6,500 CYD/day for soil backfill assuming two excavators at the soil borrow site, 30 – 35 commercial haul trucks and up to three dozers and two compactors placing, grading and compacting the soil backfill in the WDA. Applying the placement rate to 5 working days per week, omitting soil import during the Jasper County frost law period (January 15th – April 15th), and a suitable borrow site located

within a 20-mile radius, equates to a duration of approximately fourteen months for soil backfill. A reduced placement rate of 1,000 CYD/day for topsoil was applied to account for seeding, fertilizing and mulching the topsoil, equating to three months for initial site stabilization. If necessary, additional means and methods may be employed to adjust the schedule and/or duration of backfill activities such as, increased borrow and on-site stockpile prior to periods of frost law restrictions, increased work-week and/or work-day schedules.

Table 3.2 – WDA CCR Removal Schedule Milestones contains a list of milestone dates that were developed as part of the closure construction planning and scheduling to demonstrate that closure will be completed within the self-implementing closure schedule per 40 CFR 257.102(f)(1)(ii).

Table 3.2: WDA CCR Removal Schedule Milestones

Closure Component	Start Date	End Date	Duration (Months)
WDA Final Closure Construction Plans	7/19/2024	1/15/2025	6
WDA Final Closure Review/Approval by IDEM	1/15/2025	1/15/2026	12
WDA NPDES Permit Review/Approval for Dewatering	5/19/2025	9/16/2025	4
Contractor Bidding/Procurement	11/16/2025	2/14/2026	3
Cease Receipt of WDA Waste Streams	**8/31/2025**	**9/1/2025**	0
Notification of Intent to Initiate Closure	9/2/2025	9/3/2025	0
Begin WDA Closure Construction	**9/15/2025**	**9/16/2025**	0
Surficial Dewatering	9/16/2025	12/15/2025	3
Contractor Mobilization	4/15/2026	5/1/2026	1
Interstitial Dewatering	4/24/2026	4/24/2027	12
CCR Excavation	7/18/2026	5/8/2027	10
Soil Backfill Placement and Grading	4/16/2027	6/22/2028	14
Topsoil / Seed / Fertilizer / Mulch	5/10/2028	8/16/2028	3
WDA Closure Construction Complete	**8/16/2028**	**8/17/2028**	0
PE Closure Certification	8/17/2028	9/17/2028	1

4.0 CLOSURE PLAN AMENDMENTS

NIPSCO LLC may amend the closure approach and closure plan details in the future as provided for in 40 CFR §257.102(b)(3). However, under no circumstances will any closure plan revision propose a closure completion date beyond October 17, 2028. A record of amendments to the closure plan will be tracked below. The latest

version of the closure plan will be noted on the front cover of the closure plan which will be included in the Facility operating record and posted to the NIPSCO LLC's publicly accessible internet website.

Table 4.1: WDA Closure Plan Amendment Log

Version	Date	Description of Changes Made
1	October 12, 2016	Initial Issue (Haley & Aldrich, Inc)
2	February 7, 2019	Date of Closure Updated (Haley & Aldrich, Inc)
3	June 12, 2019	Update to Introductory Text (Haley & Aldrich, Inc)
4	October 8, 2020	Update to Closure by Removal, or Hybrid Closure Approach and Schedule Revision (Haley & Aldrich, Inc)
5	October 30, 2020	Revision to Closure by Removal Approach and Development of Detailed Closure Schedule (Golder Associates, Inc)

5.0 REFERENCES

"Standards for the Disposal of Coal Combustion Residuals in Landfills and Surface Impoundments" Title 40 – Protection of the Environment Part 257 – Criteria for Classification of Solid Waste Disposal Facilities and Practices Subpart D – Standards for the Disposal of Coal Combustion Residuals in Landfills and Surface Impoundments

Golder Associates, R. M. Schahfer Generating Station Ash Pond Assessment Report, Revised June 2020.

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Figures

RMSGS
FIGURE 01

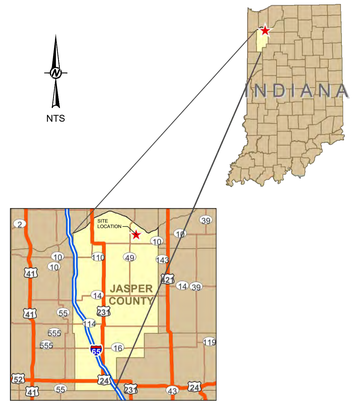
FINAL SETTLING BASIN

RM SCHAHFER GENERATING STATION

COAL DUMPER
MAINTENANCE SHOP
PUMP HOUSE
MCWB INFLOW STRUCTURE
EQUIPMENT STORAGE
PUMP HOUSE
COOLING TOWER
COOLING TOWER
COOLING TOWER
MSRB INFLOW STRUCTURE
COAL STORAGE
MATERIAL STORAGE RUNOFF BASIN
METAL CLEANING WASTE BASIN
FIRE TRAINING AREA
RETIRED WASTE DISPOSAL AREA
WASTE RUNOFF AREA
RETIRED WASTE DISPOSAL AREA
PUMP HOUSE
SLUICE PIPE STAND
WDA INFLOW STRUCTURE
SLUICE PIPE STAND
PROJECT SITE (SEE FIGURE 02)
EMERGENCY SPILLWAY
DAVIS DITCH
WASTE DISPOSAL AREA W.S.E. = 676.3
RECYCLE BASIN W.S.E. = 675.5
SLURRY WALL (TYP.)
WDA/RECYCLE BASIN OVERFLOW WIER
RAILROAD
DAVIS DITCH

PROJECT LOCATION MAP

NTS



LEGEND

EXISTING SLURRY WALL

NOTES

REFERENCE

1. AERIAL PHOTO COURTESY OF BING IMAGES, 2020 MICROSOFT CORPORATION, 2020 MAXAR, CNES (2020) DISTRIBUTION AIRBUS DS, PHOTO DATE MARCH-MAY 2019.

0 400 800
1" = 400' FEET

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GOLDER

Golder Associates, Inc.
1133 Quail Court, Suite 115, Pewaukee, WI 53072
Phone: +1(262) 347-0561

REV.	W.O.	DESCRIPTION	DATE	APP'D DRAFT	APP'D ENGR.	FILM
4						
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2						
1						

NIPSCO

DRAWN:	SDA
ENGINEER:	JDP
APPROVED:	RAW
DATE:	2020-10-27
SCALE:	AS SHOWN

TITLE	RM SCHAHFER GENERATING STATION
LOCATION	WHEATFIELD, INDIANA
DETAIL	SITE LOCATION MAP WASTE DISPOSAL AREA CLOSURE
W.O./ACCT. NO.	20368079

FIGURE	REV.
01	0

RMSGS FIGURE 02

RETIRED WASTE DISPOSAL AREA

WDA INFLOW STRUCTURE

SLUICE PIPE STAND

SLUICE PIPE STAND

SLUICE PIPE STAND

EMERGENCY SPILLWAY

WASTE DISPOSAL AREA
W.S.E. = 676.3

RECYCLE BASIN
W.S.E. = 675.5

DAVIS DITCH

WDA/RECYCLE BASIN OVERFLOW WIER

WDA UNIT BOUNDARY

SLURRY WALL (TYP.)

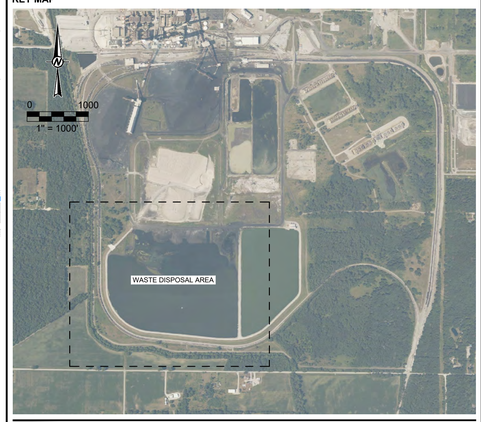
RAILROAD

DAVIS DITCH

DAVIS DITCH

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1" = 100' FEET

KEY MAP



LEGEND

- EXISTING ACCESS ROAD (GRAVEL)
- EXISTING RAILROAD
- EXISTING SLURRY WALL
- EXISTING WDA UNIT BOUNDARY
- 680 EXISTING GROUND ELEVATION CONTOUR (5ft INTERVAL)
- 679 EXISTING GROUND ELEVATION CONTOUR (1ft INTERVAL)

NOTES

1. ONLY UTILITIES OBSERVED AT THE TIME OF SURVEY WERE RECORDED. ADDITIONAL UTILITIES EXIST IN ADDITION TO THOSE SHOWN HEREON.
2. ADDITIONAL INFORMATION:
   STREET ADDRESS: 2723 E 1500 N,WHEATFIELD, INDIANA 46392
   COUNTY: JASPER
   USGS QUADRANGLE MAP: DUNE ACRES
3. USE CAUTION WHEN WORKING BENEATH OVERHEAD ELECTRICAL TRANSMISSION LINES, IN ACCORDANCE WITH THE OWNER'S REQUIREMENTS. VERIFY ADEQUATE CLEARANCE FOR EQUIPMENT. PRIOR TO PERFORMING WORK, SELECT EQUIPMENT AND CONDUCT OPERATIONS TO MAINTAIN ADEQUATE CLEARANCE BENEATH ELECTRICAL CONDUCTORS.

REFERENCES

1. EXISTING TOPOGRAPHIC MAPPING SHOWN WAS DEVELOPED BY DLZ INDUSTRIAL, LLC, 316 TECH DRIVE, BURNS HARBOR, INDIANA 46304, DATED OCTOBER 6, 2017. MAPPING PROVIDED BY WOOD ENVIRONMENT & INFRASTRUCTURE SOLUTIONS, INC. CONTAINED WITHIN AUTOCAD DRAWING FILE "8103TO-RMSGS 2017-09-27.DWG" RECEIVED SEPTEMBER 28, 2020.
2. EXISTING TOPOGRAPHIC CONTOURS SHOWN PROVIDED BY WOOD ENVIRONMENT & INFRASTRUCTURE SOLUTIONS, INC. BASED ON 3D SURFACE MODEL "EXIST" CONTAINED WITHIN AUTOCAD DRAWING FILE "20190507_WDA PERMIT SET.DWG" RECEIVED OCTOBER 15, 2020.
3. HORIZONTAL SURVEY CONTROL HEREON SHOWS COORDINATE VALUES IN INDIANA COORDINATE SYSTEM OF 1983 (NAD 83, WEST ZONE). UNITS ARE IN US FEET.
4. VERTICAL SURVEY CONTROL BASED ON NAVD88 (NORTH AMERICAN DATUM 1988).

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REV.	W.O.	DESCRIPTION	DATE	APP'D DRAFT	APP'D ENGR.	FILM
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NIPSCO

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SCALE:	AS SHOWN

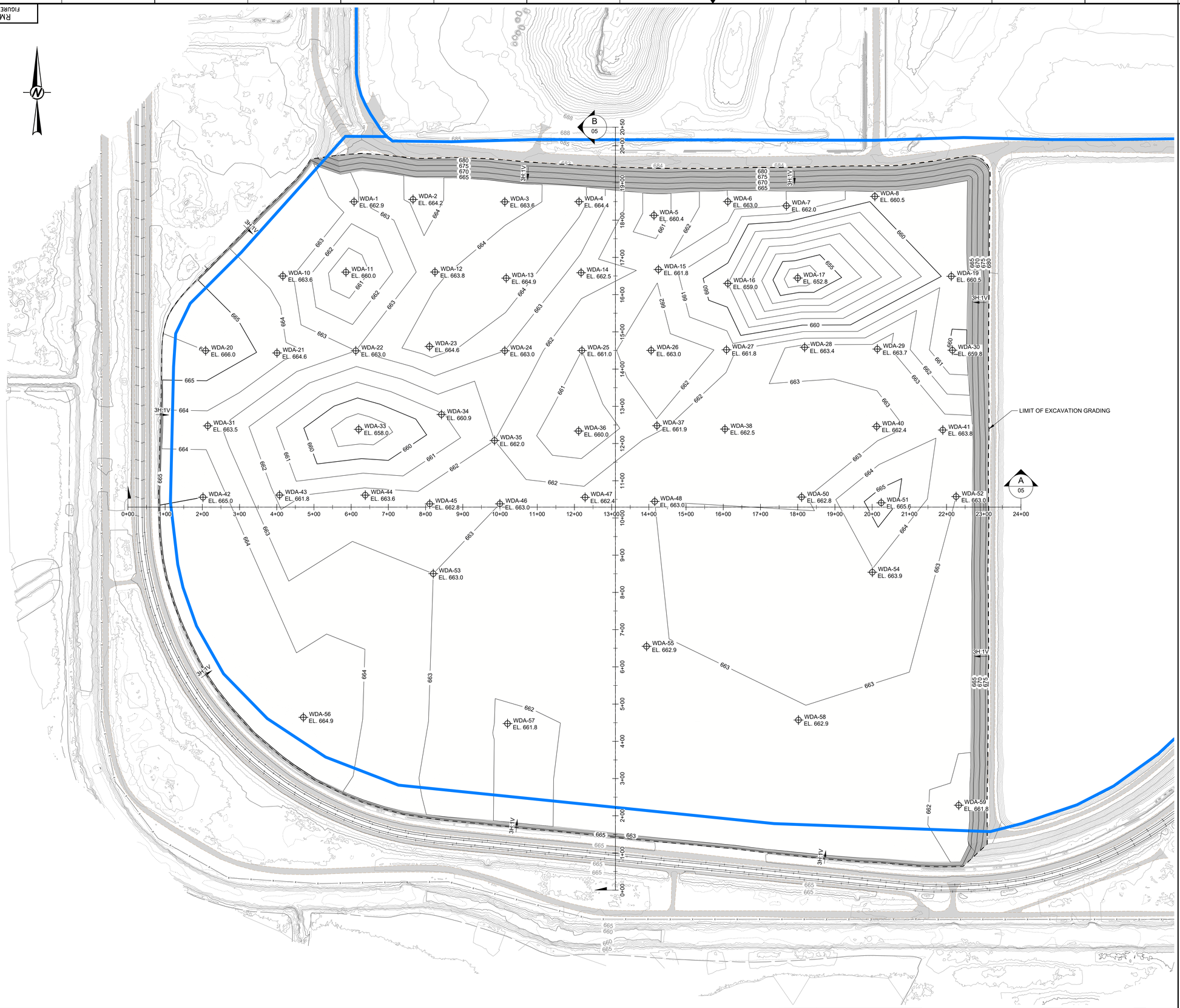
TITLE: RM SCHAHFER GENERATING STATION
LOCATION: WHEATFIELD, INDIANA
DETAIL: EXISTING CONDITIONS PLAN
WASTE DISPOSAL AREA CLOSURE
W.O./ACCT. NO. 20368079

FIGURE: 02
REV.: 0

0" 1" 2"

P:\NIPSCO\PROJECTS\20143846_RMSGS_OwnersEngineering\PRODUCTION\C - Waste Disposal Area Conceptual Closure\20368079-WDA-Concept-Closure_Existing-Conditions.dwg Oct 27, 2020 - 3:52pm By: STandelson

RMSGS FIGURE 03



KEY MAP



LEGEND

- EXISTING ACCESS ROAD (GRAVEL)
- EXISTING RAILROAD
- EXISTING SLURRY WALL
- 680 — EXISTING GROUND ELEVATION CONTOUR (5ft INTERVAL)
- 679 — EXISTING GROUND ELEVATION CONTOUR (1ft INTERVAL)
- 665 — PROPOSED EXCAVATION CONTOUR (5ft INTERVAL)
- 663 — PROPOSED EXCAVATION CONTOUR (1ft INTERVAL)
- WDA-1 EL. 662.9 — CPT/SPT BORING LOCATION / ID / EXISTING BOTTOM OF CCR ELEVATION

NOTES

1. ONLY UTILITIES OBSERVED AT THE TIME OF SURVEY WERE RECORDED. ADDITIONAL UTILITIES EXIST IN ADDITION TO THOSE SHOWN HEREON.
2. ADDITIONAL INFORMATION:
   STREET ADDRESS: 2723 E 1500 N,WHEATFIELD, INDIANA 46392
   COUNTY: JASPER
   USGS QUADRANGLE MAP: DUNE ACRES
3. USE CAUTION WHEN WORKING BENEATH OVERHEAD ELECTRICAL TRANSMISSION LINES, IN ACCORDANCE WITH THE OWNER'S REQUIREMENTS. VERIFY ADEQUATE CLEARANCE FOR EQUIPMENT. PRIOR TO PERFORMING WORK, SELECT EQUIPMENT AND CONDUCT OPERATIONS TO MAINTAIN ADEQUATE CLEARANCE BENEATH ELECTRICAL CONDUCTORS.

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4. VERTICAL SURVEY CONTROL BASED ON NAVD88 (NORTH AMERICAN DATUM 1988).
5. PROPOSED EXCAVATION TOPOGRAPHY WITHIN THE WDA BASED ON CPT AND SPT BORING LOGS COMPLETED BY GOLDER BETWEEN JULY AND NOVEMBER 2019. LOGS INCLUDED IN GOLDER REPORT "R. M. SCHAHFER GENERATING STATION ASH POND ASSESSMENT REPORT" REVISED JUNE 2020.

CUT DEPTH TABLE

RANGE NUMBER	MAX. DEPTH	MIN. DEPTH	3D AREA (SQ. FT)	2D AREA (ACRES)	VOLUME (CY)
1	-23.8	-15.0	540,607	12.34	62,944
2	-15.0	-10.0	983,618	22.40	196,805
3	-10.0	-5.0	262,076	5.81	302,198
4	-5.0	0.0	1,940,326	44.36	472,198

CUT TOTAL VOLUME ESTIMATE

Base Surface	EG-RMSGS-WDA-ExTopo-2017-10-06
Comparison Surface	DG-RMSGS-WDA-PropExcavation-Concept-1
Cut Factor	1.00
Fill Factor	1.00
Cut volume	1,034,144.85 Cu. Yd.
Fill volume	0.00 Cu. Yd.
Net volume	**1,034,144.85 Cu. Yd.**

0 100 200
1" = 100' FEET

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Phone: +1(262) 347-0561

REV.	W.O.	DESCRIPTION	DATE	APP'D DRAFT	APP'D ENGR.	FILM
4						
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NIPSCO

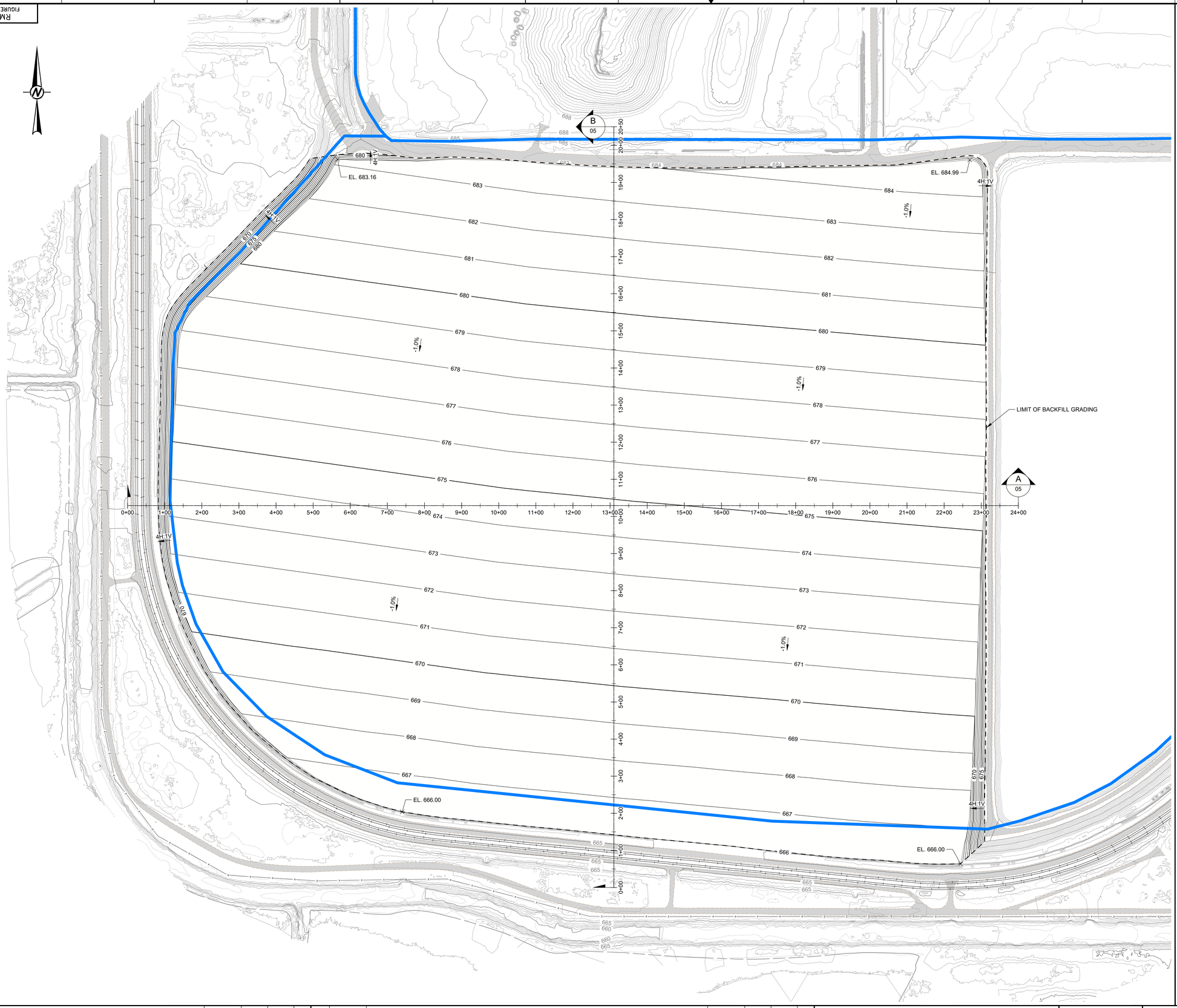
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APPROVED:	RAW
DATE:	2020-10-27
SCALE:	AS SHOWN

TITLE RM SCHAHFER GENERATING STATION
LOCATION WHEATFIELD, INDIANA
DETAIL PROPOSED CCR EXCAVATION GRADES
WASTE DISPOSAL AREA CLOSURE
W.O./ACCT. NO. 20368079

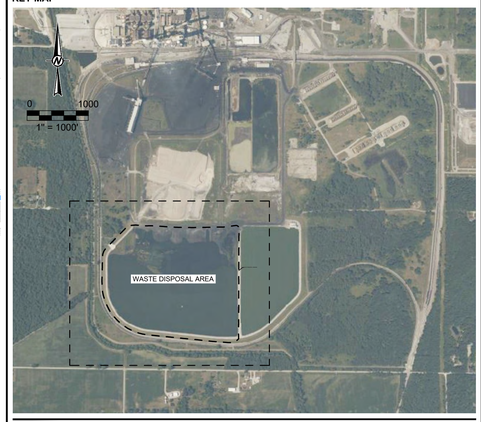
FIGURE 03 REV. 0

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RMSGS
FIGURE 04



KEY MAP



LEGEND

- EXISTING ACCESS ROAD (GRAVEL)
- EXISTING RAILROAD
- EXISTING SLURRY WALL
- 680 — EXISTING GROUND ELEVATION CONTOUR (5ft INTERVAL)
- 679 — EXISTING GROUND ELEVATION CONTOUR (1ft INTERVAL)
- 680 — PROPOSED BACKFILL FINAL COVER CONTOUR (5ft INTERVAL)
- 679 — PROPOSED BACKFILL FINAL COVER CONTOUR (1ft INTERVAL)

NOTES

1. ONLY UTILITIES OBSERVED AT THE TIME OF SURVEY WERE RECORDED. ADDITIONAL UTILITIES EXIST IN ADDITION TO THOSE SHOWN HEREON.
2. ADDITIONAL INFORMATION:
   STREET ADDRESS: 2723 E 1500 N,WHEATFIELD, INDIANA 46392
   COUNTY: JASPER
   USGS QUADRANGLE MAP: DUNE ACRES
3. USE CAUTION WHEN WORKING BENEATH OVERHEAD ELECTRICAL TRANSMISSION LINES, IN ACCORDANCE WITH THE OWNER'S REQUIREMENTS. VERIFY ADEQUATE CLEARANCE FOR EQUIPMENT. PRIOR TO PERFORMING WORK, SELECT EQUIPMENT AND CONDUCT OPERATIONS TO MAINTAIN ADEQUATE CLEARANCE BENEATH ELECTRICAL CONDUCTORS.

REFERENCES

1. EXISTING TOPOGRAPHIC MAPPING SHOWN WAS DEVELOPED BY DLZ INDUSTRIAL, LLC, 316 TECH DRIVE, BURNS HARBOR, INDIANA 46304, DATED OCTOBER 6, 2017. MAPPING PROVIDED BY WOOD ENVIRONMENT & INFRASTRUCTURE SOLUTIONS, INC. CONTAINED WITHIN AUTOCAD DRAWING FILE "8103TO-RMSGS 2017-09-27.DWG" RECEIVED SEPTEMBER 28, 2020.
2. EXISTING TOPOGRAPHIC CONTOURS SHOWN PROVIDED BY WOOD ENVIRONMENT & INFRASTRUCTURE SOLUTIONS, INC. BASED ON 3D SURFACE MODEL "EXIST" CONTAINED WITHIN AUTOCAD DRAWING FILE "20190507_WDA PERMIT SET.DWG" RECEIVED OCTOBER 15, 2020.
3. HORIZONTAL SURVEY CONTROL HEREON SHOWS COORDINATE VALUES IN INDIANA COORDINATE SYSTEM OF 1983 (NAD 83, WEST ZONE). UNITS ARE IN US FEET.
4. VERTICAL SURVEY CONTROL BASED ON NAVD88 (NORTH AMERICAN DATUM 1988).

FILL DEPTH TABLE

RANGE NUMBER	MIN. DEPTH	MAX. DEPTH	3D AREA (SQ. FT)	2D AREA (ACRES)	VOLUME (CY)
1	0.0	5.0	442,232	10.01	683,874
2	5.0	10.0	1,199,149	27.45	512,939
3	10.0	15.0	937,250	21.45	311,937
4	15.0	28.6	1,238,608	28.37	157,998

FILL TOTAL VOLUME ESTIMATE

Base Surface	DG-RMSGS-WDA-PropExcavation-Concept-1
Comparison Surface	DG-RMSGS-WDA-PropFinalCover-Concept-1
Cut Factor	1.00
Fill Factor	1.00
Cut volume	0.00 Cu. Yd.
Fill volume	1,666,748.44.88 Cu. Yd.
Net volume	**1,666,748.44 Cu. Yd.<Fill>**

0 100 200
1" = 100' FEET

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GOLDER
Golder Associates, Inc.
1133 Quail Court, Suite 115, Pewaukee, WI 53072
Phone: +1(262) 347-0561

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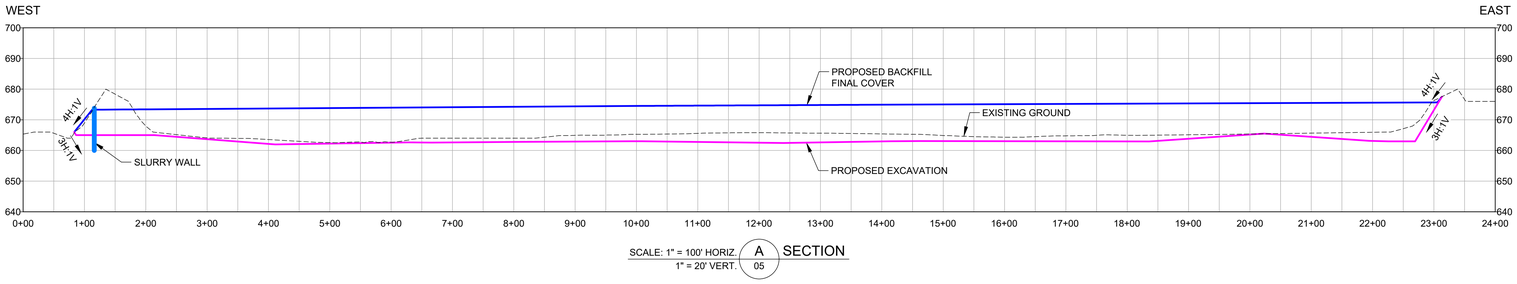
NIPSCO

DRAWN:	SDA
ENGINEER:	JDP
APPROVED:	RAW
DATE:	2020-10-27
SCALE:	AS SHOWN

TITLE RM SCHAHFER GENERATING STATION
LOCATION WHEATFIELD, INDIANA
DETAIL PROPOSED BACKFILL GRADES
WASTE DISPOSAL AREA CLOSURE
W.O./ACCT. NO. 20368079

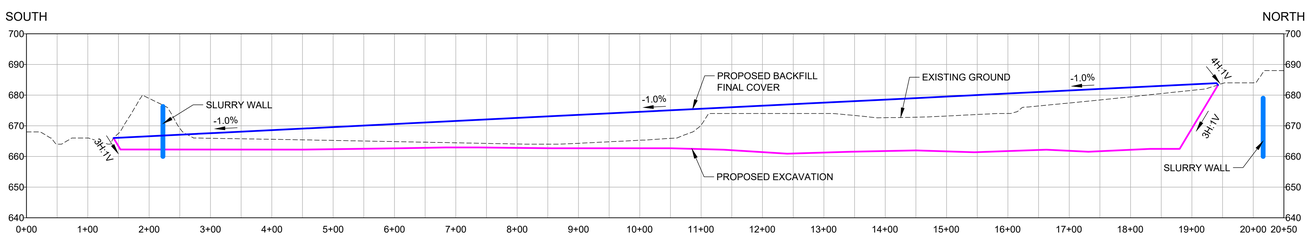
FIGURE 04 REV. 0

RMSGS FIGURE 05



SCALE: 1" = 100' HORIZ.
1" = 20' VERT.

A 05 SECTION



SCALE: 1" = 100' HORIZ.
1" = 20' VERT.

B 05 SECTION

KEY MAP



LEGEND

- EXISTING GROUND (SEPTEMBER 2017 SURVEY)
- EXISTING SLURRY WALL
- PROPOSED EXCAVATION GRADE
- PROPOSED BACKFILL FINAL COVER GRADE

NOTES

REFERENCES

1. EXISTING GROUND SHOWN BASED ON MAPPING DEVELOPED BY DLZ INDUSTRIAL, LLC, 316 TECH DRIVE, BURNS HARBOR, INDIANA 46304, DATED OCTOBER 6, 2017.
2. EXISTING GROUND SHOWN PROVIDED BY WOOD ENVIRONMENT & INFRASTRUCTURE SOLUTIONS, INC. BASED ON 3D SURFACE MODEL "EXIST" CONTAINED WITHIN AUTOCAD DRAWING FILE "20190507_WDA PERMIT SET.DWG" RECEIVED OCTOBER 15, 2020.
3. VERTICAL SURVEY CONTROL BASED ON NAVD88 (NORTH AMERICAN DATUM 1988).

0 100 200
1" = 100' HORIZ. FEET

0 20 40
1" = 20' VERT. FEET

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1						

NIPSCO

DRAWN:	SDA
ENGINEER:	JDP
APPROVED:	RAW
DATE:	2020-10-27
SCALE:	AS SHOWN

TITLE RM SCHAHFER GENERATING STATION
LOCATION WHEATFIELD, INDIANA
DETAIL CROSS SECTIONS
WASTE DISPOSAL AREA CLOSURE
W.O./ACCT. NO. 20368079

FIGURE 05 REV. 0

P:\NIPSCO\PROJECTS\2014-5846_RMSGS_OwnersEngineering\PRODUCTION\C - Waste Disposal Area Conceptual Closure\20368079-WDA-Concept-Closure_SECTIONS.dwg Oct 27, 2020 - 5:18pm By: STAnderson

RMSGS
FIGURE 06

Oct-23 | Feb-24 | Jun-24 | Oct-24 | Feb-25 | Jun-25 | Oct-25 | Feb-26 | Jun-26 | Oct-26 | Feb-27 | Jun-27 | Sep-27 | Jan-28 | May-28 | Sep-28

WDA Final Closure Construction Plans

WDA Final Closure Review/Approval by IDEM

WDA NPDES Permit Review/Approval for Dewatering

Contractor Bidding/Procurement

9/1/2025
Cease Receipt of WDA Waste Streams

9/3/2025
Notification of Intent to Initiate Closure

9/16/2025
Begin WDA Closure Construction

Surficial Dewatering

Contractor Mobilization

Interstitial Dewatering

CCR Excavation

Soil Backfill Placement

Topsoil / Seed / Fertilizer / Mulch

8/17/2028
WDA Closure Construction Complete

Closure Certification

9/17/2028
PE Closure Certification

C:\Users\mbolsvert.GOLDER\Desktop\NIPSCO (1)\NIPSCO\P20145846-RMSGS_OwnersEngineering\PRODUCTION\C - Waste Disposal Area Conceptual\Closure\20368079-WDA-Concept-Closure_GANTT Chart Schedule.dwg Oct 28, 2020 - 1:29pm By: mbolsvert

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Phone: +1(262) 347-0561

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1						

NIPSCO

DRAWN:	SDA
ENGINEER:	JDP
APPROVED:	RAW
DATE:	2020-10-28
SCALE:	NTS

TITLE RM SCHAHFER GENERATING STATION
LOCATION WHEATFIELD, INDIANA
DETAIL WDA CCR CLOSURE BY REMOVAL SCHEDULE
WASTE DISPOSAL AREA CLOSURE
W.O./ACCT. NO. 20368079

FIGURE	REV.
06	0



golder.com

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

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

Exhibit 89
2025 OMS-MISO Survey

2025 OMS-MISO Survey Results

Furthering our joint commitment to regional resource adequacy, OMS and MISO are pleased to announce the results of the 2025 OMS-MISO Survey

June 6, 2025

Updated 6/6/2025: Slide 21

Executive Summary

The 2025 OMS-MISO Survey reinforces near-term risks and highlights key uncertainties impacting resource adequacy

- Projections result in a potential surplus ranging from 1.4 GW to 6.1 GW for summer 2026. At least 3.1 GW* of additional capacity beyond the committed capacity will be needed to meet the projected planning reserve margin forecast.
- Queue and market reforms, improved resource deployment timelines and other initiatives will help maintain resource adequacy through 2031.
    - Replacement and surplus queue projects will mitigate the impact of retirements by using existing interconnection service, supplying ~25% of new capacity additions.
- As solar penetration grows, reliability risks are spreading into winter from summer.
- Load growth, driven by economic development, is outpacing previous forecasts with a 2.2% compound annual growth rate over five years.
- Resource accreditation reforms (e.g., Direct Loss of Load in PY 2028/29) are expected to provide a clearer view of resource adequacy, system-level outlooks remain consistent with current methods.

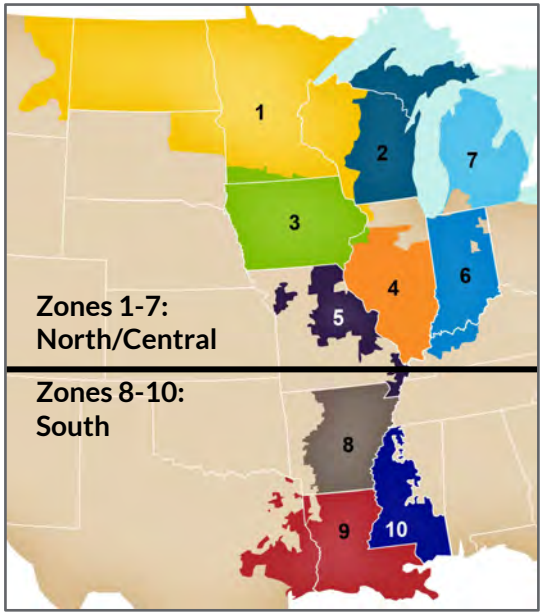
All references to capacity in this presentation indicate seasonal accredited capacity (SAC), unless noted otherwise.

*See slide 7 for data which illustrates the projected Planning Reserve Margin Requirement with Load Serving Entities' forecast (137.3 GW) minus Committed Capacity (134.2) for PY 2026/27.

The OMS-MISO Survey provides a resource adequacy view over a five-year horizon based on currently available information

The survey* results indicate the degree to which expected capacity resources satisfy planning reserve margin requirements with either a surplus or a deficit

- 91% of existing generation participated in the 2025 OMS-MISO Survey, representing 97.4% of MISO load.
- Various projected capacity scenarios and large spot-load additions highlight the increasing uncertainty and evolving risk.
- Load Serving Entities (LSEs) are expected to have adequate resources to meet load reserve requirements in each zone.
- MISO zonal views are not included this year as the annual capacity import limit and capacity export limit study will provide value updates and be reported in the Loss of Load Expectation report in November.



The survey serves as a point-in-time analysis based on data collected during April 2025.

Additional factors can impact projected deficits or surpluses that are observed in the survey

Downside Risks

- Winter reliability risk intensifies due to low solar accreditation during the season
- Rapid industrial and commercial growth adds pressure on resource adequacy
- Continued backlog and uncertainty in generation queue (296 GW) complicates timely resource additions
  - 54 GW of signed Generation Interconnection Agreements (GIAs) not yet online (71% of which are wind and solar)
- Accelerated pace of resource retirements is driven by regulatory pressures, economic pressures and aging infrastructure
- Persistent supply-chain disruptions, labor constraints and permitting challenges delay new resource deployments

Upside Possibilities

- Market reforms, including Reliability-Based Demand Curve and accreditation updates, provide clearer and stronger investment signals
- Enhanced forecasting methods recognizing replacement/ surplus units improve accuracy and confidence
- Queue reforms reduce speculative projects and streamline resource integration processes
- Retirement deferrals offer a potential short-term reliability buffer against seasonal projected capacity shortfalls
- Easing of supply, labor, or permitting constraints could speed deployments

Summer Seasonal Accreditation Values

Resource Category	2025 Survey	2024 Survey
Potentially Unavailable Resources	• No Changes	• Indicated as "Low Certainty" in survey results by market participants • Includes potential retirements or suspensions • Assumes resources will **not** be used to meet PRMR

Potential New Capacity – *New Point of Interconnection*	• **Historical Projection:** Results in **3.5 GW/yr**
	  • *Driven by 2022-2024 actuals*
	• **Emerging Projection:** Results in **6.2 GW/yr** average
	  • *Informed by member responses to OMS-MISO Survey request, these members represent 97% of the load in the footprint*
	  • *Fuel mix of new resources indicated by OMS-MISO Survey member responses*
		• **Using 3-Year Historical Average:** Capacity addition (2.3 GW/yr) based on the average new capacity built in Planning Years 2020-2022
		• **Using Alternative Projection:** Informed by timing estimates from interconnection customers with signed Generator Interconnection Agreement projects* (6.1 GW/yr)
		• Assumes resources **will** be used to meet PRMR

Replacement/ Surplus Project Impact Potential New Capacity – *Existing Point of Interconnection*	• **Replacement Impact Highlighted:** Results in additional "new resources" to offset the impacts of retirements
	• **Historical Replacement** : Valued at **1.2 GW/yr**
	  • *50% replacement & surplus queue adoption*
	• **Emerging Replacement:** Valued at **2.4 GW/yr**
	  • *100% replacement & surplus queue adoption*
	  • *The replacement queue is not directly part of MISO's queue cycle methodology, and until recently the adoption rate of future replacement resources was unknown*
		• Not included

Committed Capacity	• No Changes	• Existing generation resources • External resources with firm contracts to MISO load • Assumes resources will be used to meet PRMR

PRMR: *Planning Reserve Margin Requirement*
Committed Capacity: *Resources committed to serving MISO's load*
Potentially Unavailable Resources: *May be available to serve MISO's load but may not have firm commitments*

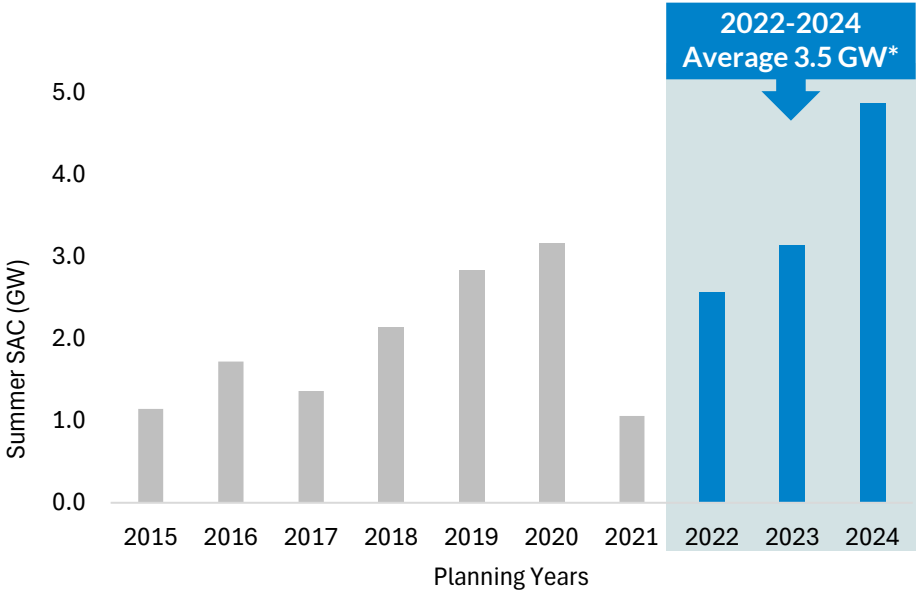
Trends and market pressures related to new capacity additions suggest that refinements are needed to better reflect uncertainty

Previously, MISO used probability-adjusted estimates for projects in various queue phases. Due to the significantly larger queue and constraints on projects with signed Generation Interconnection Agreements (GIAs), this approach no longer applies. As in 2024, the 2025 survey employs two estimates:

1. **Three-Year Historical Average:** based on the historical rate of additions per planning year*
2. **Emerging Projection:** based on member submittals to the OMS-MISO Survey

These projections are combined with the MISO Surplus and Replacement Queues to create bookend capacity forecasts for the MISO footprint.

The scale and pace of new resource additions have varied over time

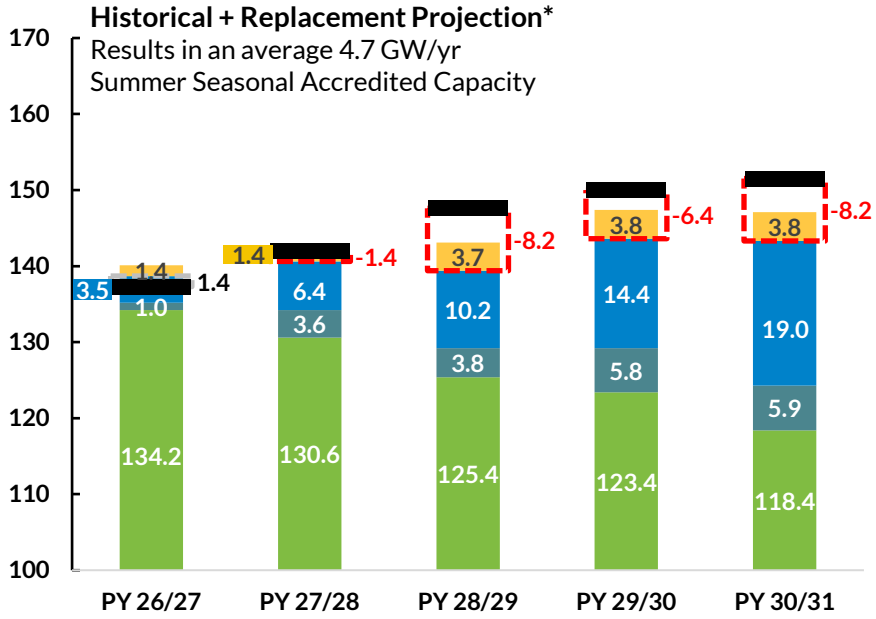


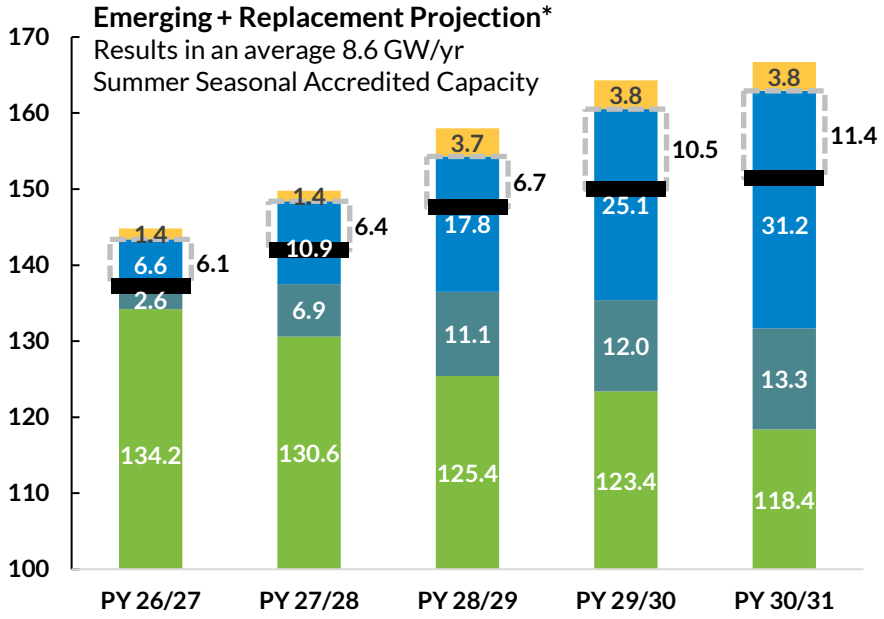
Queue applications: Nameplate 296 GW Queue & 54 GW Signed GIAs not yet online (as of 5/14/25)

**Summer seasonal accredited potential new capacity based on 2022-24 actuals*

Historical + Replacement & Emerging + Replacement Projections vs PRMR ~4.7 GW & 8.6 GW Status Quo Summer SAC Installation Rate

MISO Resource Adequacy Projections – Summer





- Projected PRMR with LSE forecast
- Potentially Unavailable Resources
- Potential New Capacity
- Value of Replacement/Surplus Projects
- Committed Capacity

Using methods for potential New Capacity described on Slide 5

***PRMR:** Planning Reserve Margin Requirement*

- Red border values indicate the additional potential deficit against the Projected PRMR
- Gray border values indicate the potential surplus against the Projected PRMR
- Capacity accreditation values and Planning Reserve Margin projections based on current practices
- Regional Directional Transfer (RDT) limit of 1900 MW is reflected in this chart

Winter Seasonal Accreditation Values

Resource Category	2025 Survey	2024 Survey
Potentially Unavailable Resources	• No Changes	• Indicated as "Low Certainty" in survey results by market participants • Includes potential retirements or suspensions • Assumes resources will **not** be used to meet PRMR

Potential New Capacity – New Point of Interconnection	• **Historical Projection:** Results in **1.4 GW/yr**
	  • *Driven by 2022-2024 actuals*
	• **Emerging Projection:** Results in **4.1 GW/yr** average
	  • *Informed by member responses to OMS-MISO Survey request, these members represent 97% of the load in the footprint*
	  • *Fuel mix of new resources indicated by OMS-MISO Survey member responses*
		• Not included

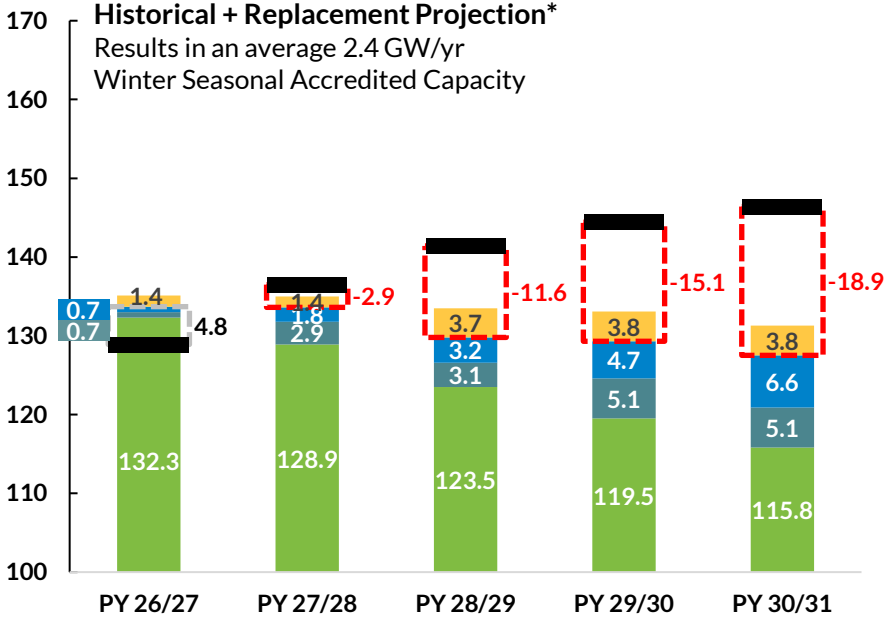
Replacement/ Surplus Project Impact Potential New Capacity – Existing Point of Interconnection	• **Replacement Impact Highlighted:** Results in additional "new resources" to offset the impacts of retirements
	• **Historical Replacement** : Valued at **1.0 GW/yr**
	  • *50% replacement & surplus queue adoption*
	• **Emerging Replacement :** Valued at **2.1 GW/yr**
	  • *100% replacement & surplus queue adoption*
	  • *The replacement queue is not directly part of MISO's queue cycle methodology, and until recently the adoption rate of future replacement resources was unknown*
		• Not included

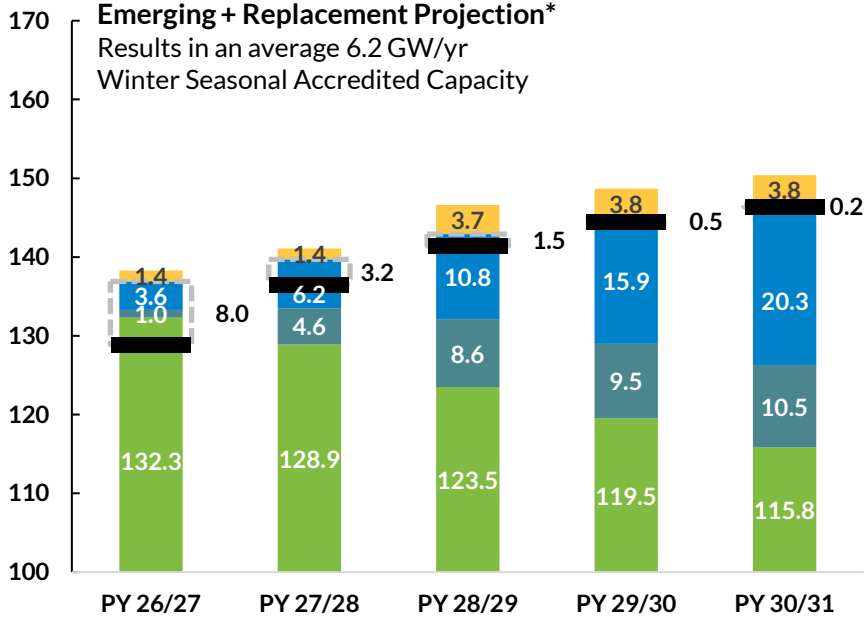
Committed Capacity	• No Changes	• Existing generation resources • External resources with firm contracts to MISO load • Assumes resources will be used to meet PRMR

PRMR: *Planning Reserve Margin Requirement*
Committed Capacity: *Resources committed to serving MISO's load*
Potentially Unavailable Resources: *May be available to serve MISO's load but may not have firm commitments*

Historical + Replacement & Emerging + Replacement Projections vs PRMR
~2.4 GW & 6.2 GW Status Quo Winter SAC Installation Rate

MISO Resource Adequacy Projections – Winter





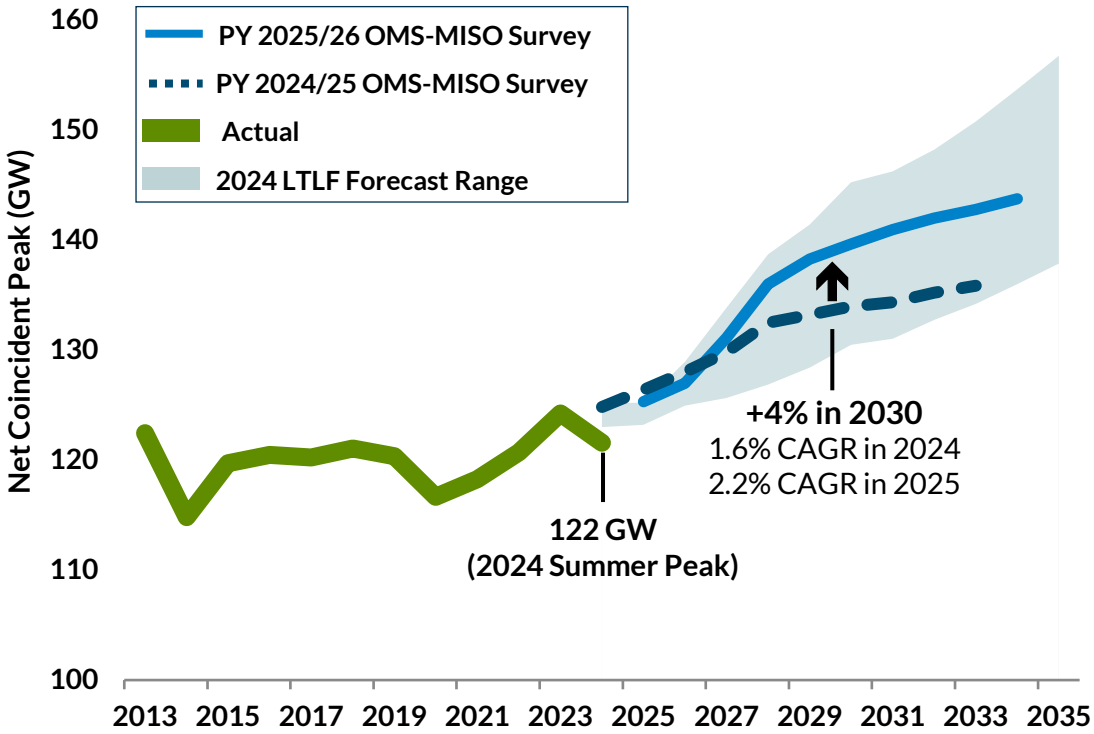
Projected PRMR with LSE forecast
Potentially Unavailable Resources
Potential New Capacity
Value of Replacement/Surplus Projects
Committed Capacity

Using methods for potential New Capacity described on Slide 8
***PRMR:** Planning Reserve Margin Requirement*

Red border values indicate the additional potential deficit against the Projected PRMR
Gray border values indicate the potential surplus against the Projected PRMR

- Capacity accreditation values and Planning Reserve Margin projections based on current practices
- Regional Directional Transfer (RDT) limit of 1900 MW is reflected in this chart

OMS-MISO Survey responses show increasing load forecasts year-over-year and are close to the high end of MISO Long-Term Load Forecast



- Load growth through 2035 will exacerbate capacity shortfall and operational risks
- Many new loads will require additional firm, controllable resources

Anticipated Impact in MISO's region
2024-44 Growth TWh Low-High*



Data Centers (149-241)

Electric Vehicles (54-91)

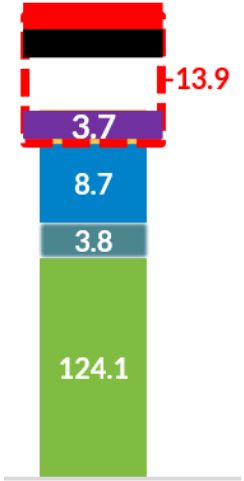
Industry Development & Offshoring (21-105)

Hydrogen (25-95)

Building Electrification (36-43)

LTLF: Long-Term Load Forecast, 2024 Long-Term Load Forecast White Paper; **CAGR:** Compound Annual Growth Rate
**Level of certainty based on expected likelihood of load growth materializing*

NEW: The 2025 OMS-MISO Survey includes sensitivities considering a range of new, large spot-load additions



PY 28/29

Illustrative example: PY 2026/27 using three-year historical average

PRMR based on Long-Term Load Forecast "High Trajectory"

- Models higher load-growth scenario per Long Term Load Forecast[1]
- Red dashed border values = deficit; gray dashed border values = surplus

PRMR based on LSE submitted load forecast

- LSE-submitted Non-Coincident Peak Forecast (NCPF) converted to Coincident Peak Forecast (CPF) using MISO-posted coincidence factors
- Transmission losses added
- PRMR calculated using out year PRM% from PY 2025/26 LOLE Study

PRMR based on Long-Term Load Forecast "Current Trajectory"

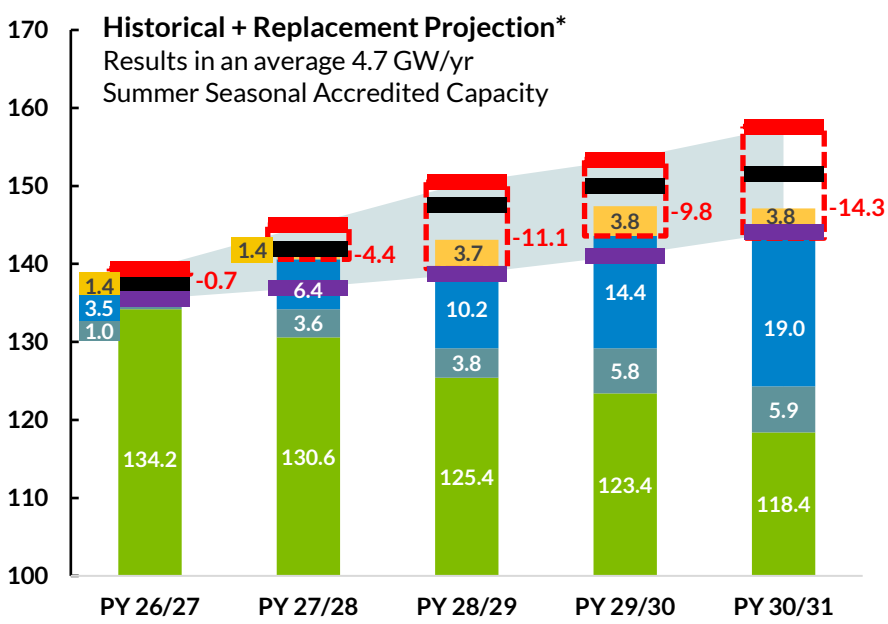
- Models lower load-growth scenario per Long-Term Load Forecast[1]

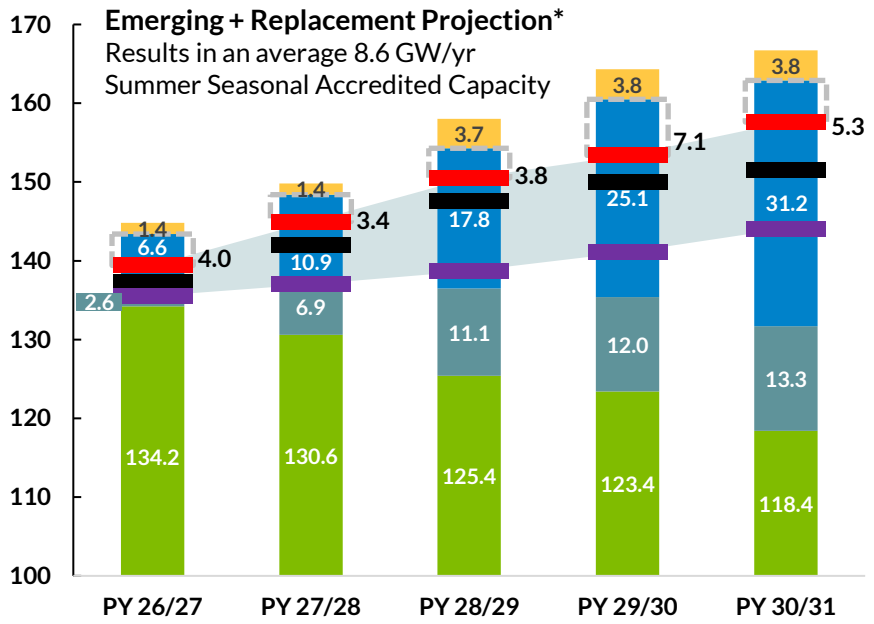
[1] MISO Long-Term Load Forecast White Paper, December 2024

PRMR: *Planning Reserve Margin Requirement* ***LSE:*** *Load Serving Entity* ***LOLE:*** *Loss of Load Expectation*

Capacity deficits continue to grow in the near and long term under a large spot-load additions scenario

MISO Resource Adequacy Projections – Summer





Planning Reserve Margin

- Projected PRMR for 'High Trajectory' scenario
- Projected PRMR for 'Current Trajectory' scenario
- Projected PRMR with LSE forecast
- Potentially Unavailable Resources
- Potential New Capacity
- Value of Replacement/Surplus Projects
- Committed Capacity

- Shaded area indicates spread between projected PRMR for "Current Trajectory" and "High Trajectory" scenario from Long-term Load Forecast
- Red border values indicate the additional potential deficit with "High Trajectory" scenario case
- Gray border values indicate the potential surplus with "High Trajectory" scenario case
- Capacity accreditation values and Planning Reserve Margin projections based on current practices

Using Potential New Capacity as described on Slide 5.

***PRMR:** Planning Reserve Margin Requirement*

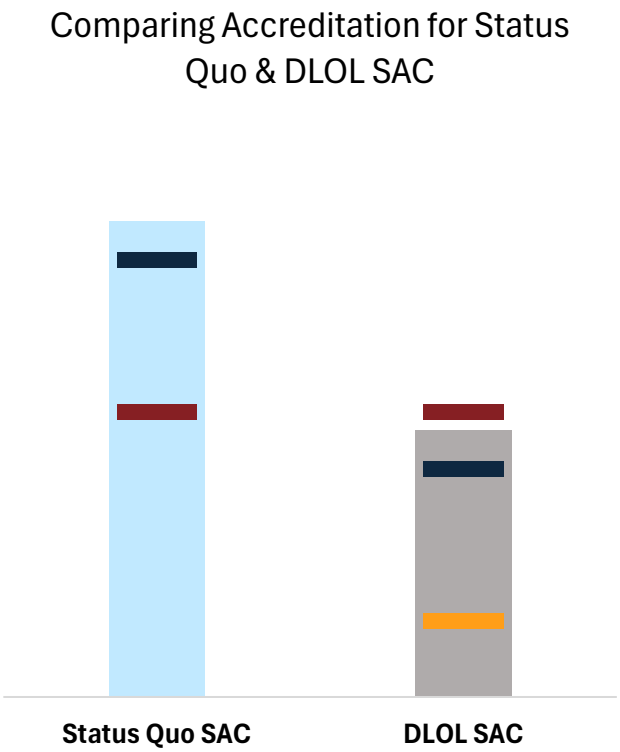
MISO's existing accreditation methods can overstate a resource's capacity value during the highest risk periods, especially as the region's risk profile changes, leading to understated risk

- Increased reliance on wind, solar and storage, projected large-load additions and electrification, and frequent large-scale weather events are decoupling periods of risk from periods of high demand.
- These drivers are upending traditional methods for establishing reliability requirements and resource accreditation.
- MISO's resource accreditation methodology* (Direct Loss of Load) will value a resource's marginal contribution to reliability during the highest risk periods.

MISO's accreditation reforms, targeted for implementation in PY 2028/29, will better measure a resource's contribution to reliability.

*See Resource Accreditation White Paper, published March 2024

High Level Description of Status Quo vs Direct Loss of Load



Peak Load Forecast
- Submitted annually by members

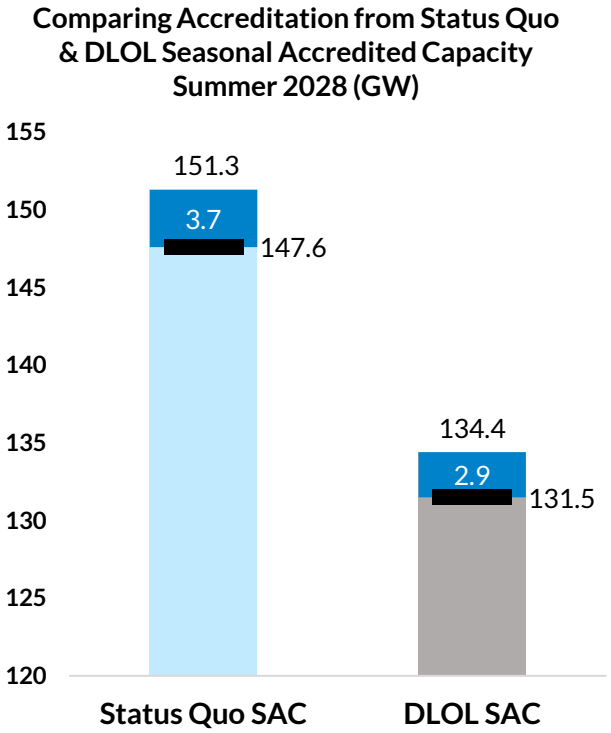
Critical Hours Load Forecast
- Illustrative only, not collected

Planning Reserve Margin Requirement (PRMR) at
- Status Quo: Peak Load
- DLOL: critical hours

Status Quo SAC value of Resources during MISO peak to meet PRMR

DLOL SAC value of Resources during critical hours to meet PRMR

Status Quo vs Direct Loss of Load Accreditation for summer 2028



- In principle, surplus/deficit moving from status quo to DLOL SAC should remain unchanged
- Modeled load and resource mix that is misaligned from OMS-MISO Survey results will cause deviations in surplus/deficit
- PY 2028/29 was most comparable in load and resource mix, which is why DLOL view is only shown for one year

Planning Reserve Margin Requirement (PRMR)
Surplus (Nearly equivalent between Status Quo & DLOL)
Status Quo SAC value of Resources during MISO peak to meet PRMR
DLOL SAC value of Resources during critical hours to meet PRMR

MISO has acted on many Reliability Imperative initiatives to address resource adequacy challenges, but there's more to be done

Ongoing Challenges

- Accelerating demand for electricity
- Rapid pace of generation retirements continue
- Loss of accredited capacity and reliability attributes
- Intermittent nature of new resource additions
- Delays of new resource additions
- More frequent extreme weather

Completed Initiatives

- ✓ Implemented Reliability-Based Demand Curve in 2025 PRA
- ✓ Generation interconnection queue cap
- ✓ Improved generator interconnection queue process (*New application portal June 2025)*
- ✓ Approved over $30 billion in new transmission lines

Initiatives In Progress

- ❑ Implement interim Expedited Resource Addition Study (ERAS) process *(2025)*
- ❑ Implement Direct Loss of Load (DLOL)-based accreditation *(PY 2028/29)*
- ❑ Enhance resource adequacy risk modeling
- ❑ Reduce queue cycle times through automation
- ❑ Demand Response and Emergency Resource reforms
- ❑ Enhance allocation of resource adequacy requirements

Key Takeaways

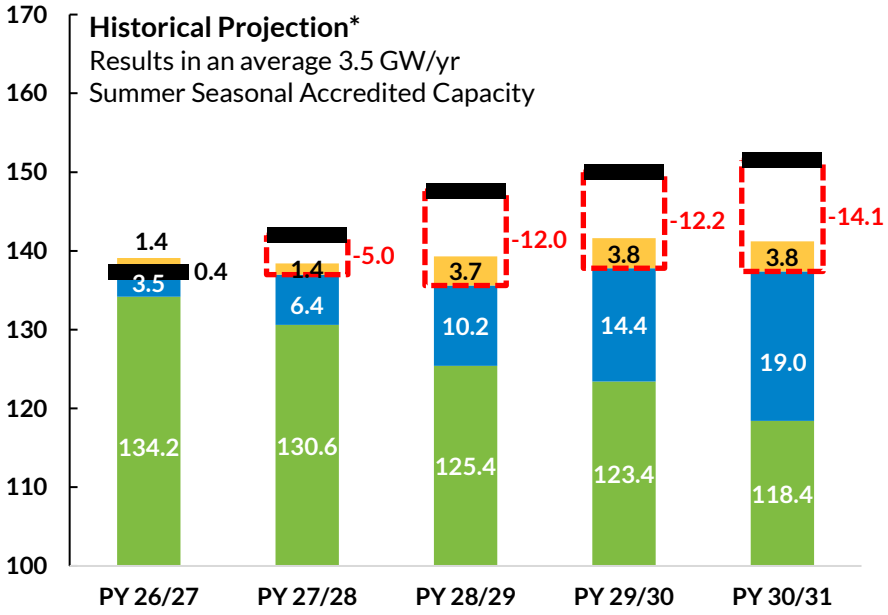
The 2025 OMS-MISO Survey emphasizes that decisions made today by utilities, regulators, MISO and its members will critically shape future resource adequacy

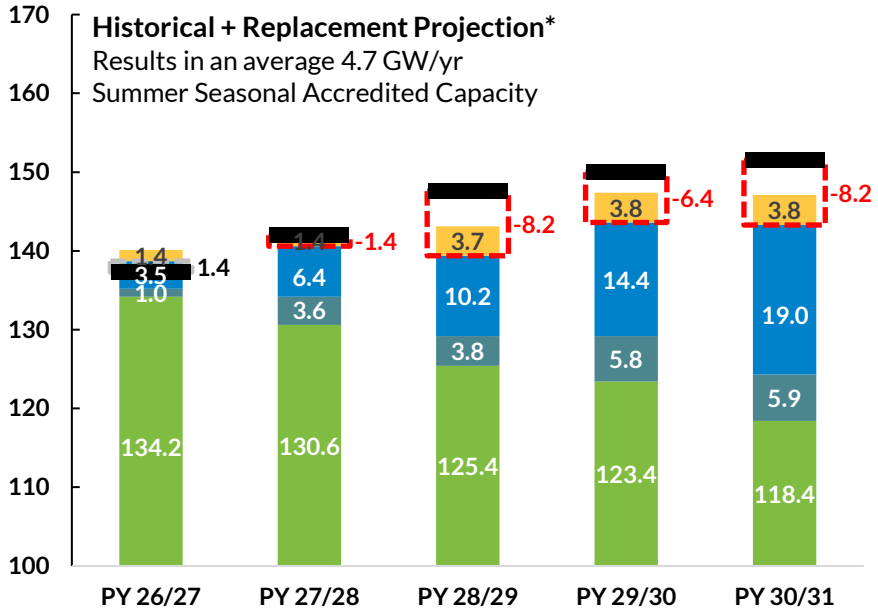
- This year's survey highlights significant uncertainty in projected resource adequacy, underscoring the urgent need for accelerated resource additions, strategic retirement planning, and proactive management of increasing load growth.
- Ongoing collaboration between OMS and MISO remains essential to address intensifying reliability risks, particularly as seasonal challenges, especially in winter, grow increasingly complex.
- Continued and immediate actions are required to streamline the addition of new capacity, align resources effectively with new load demands.
- MISO's ongoing resource adequacy reforms remain critical and responsive, directly addressing evolving reliability challenges.

Appendix

Historical & Historical + Replacement Projections vs PRMR
~3.5 GW & 4.7 GW Status Quo Summer SAC Installation Rate

MISO Resource Adequacy Projection – Summer





Projected PRMR with LSE forecast
Potentially Unavailable Resources
Potential New Capacity
Value of Replacement/Surplus Projects
Committed Capacity

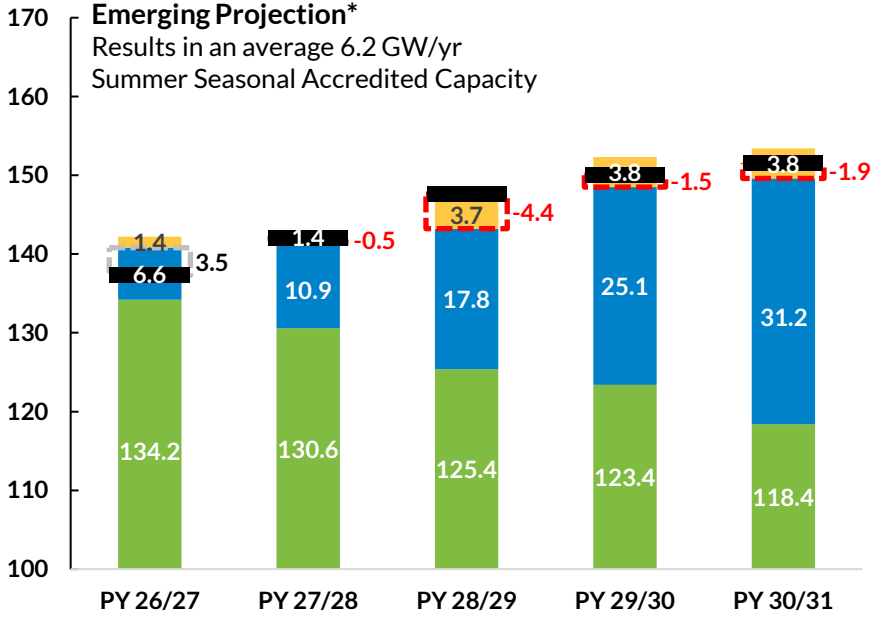
**Using methods for potential New Capacity described on Slide 5*
***PRMR:** Planning Reserve Margin Requirement*

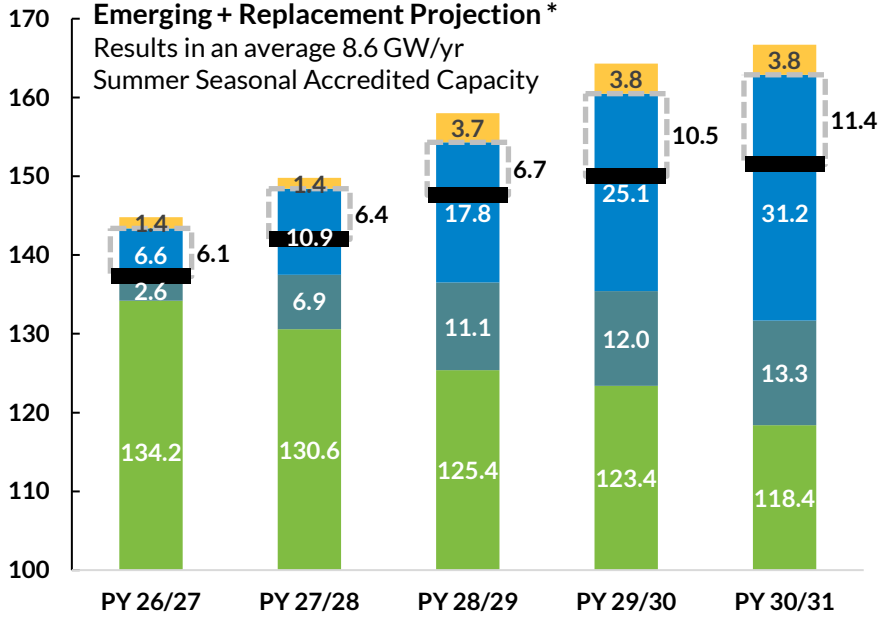
Red border values indicate the additional potential deficit against the Projected PRMR
Gray border values indicate the potential surplus against the Projected PRMR

- Capacity accreditation values and Planning Reserve Margin projections based on current practices
- Regional Directional Transfer (RDT) limit of 1900 MW is reflected in this chart

Emerging & Emerging + Replacement Projections vs PRMR
~6.2 GW & 8.6 GW Status Quo Summer SAC Installation Rate

MISO Resource Adequacy Projection – Summer





Projected PRMR with LSE forecast
Potentially Unavailable Resources
Potential New Capacity
Value of Replacement/Surplus Projects
Committed Capacity

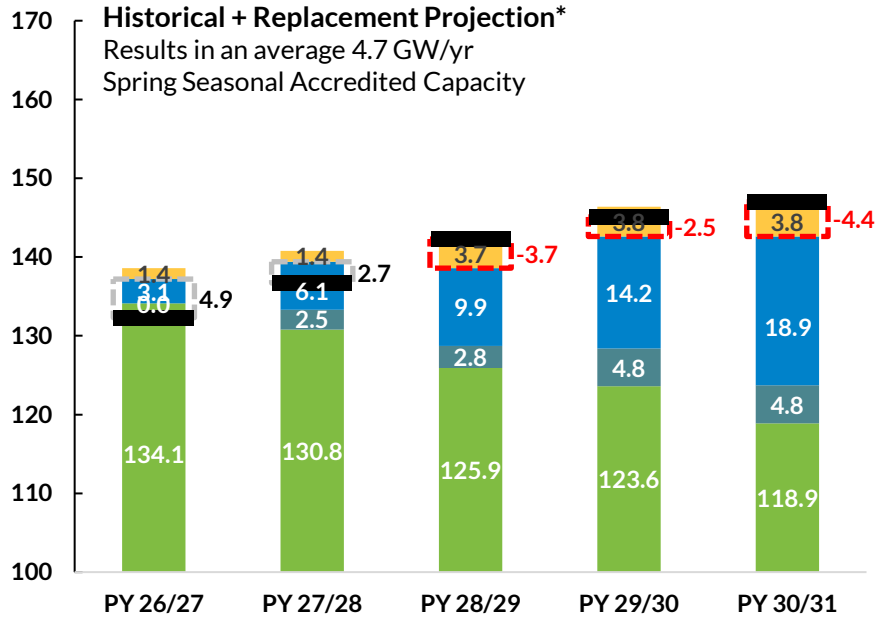
Using methods for potential New Capacity described on Slide 5
***PRMR:** Planning Reserve Margin Requirement*

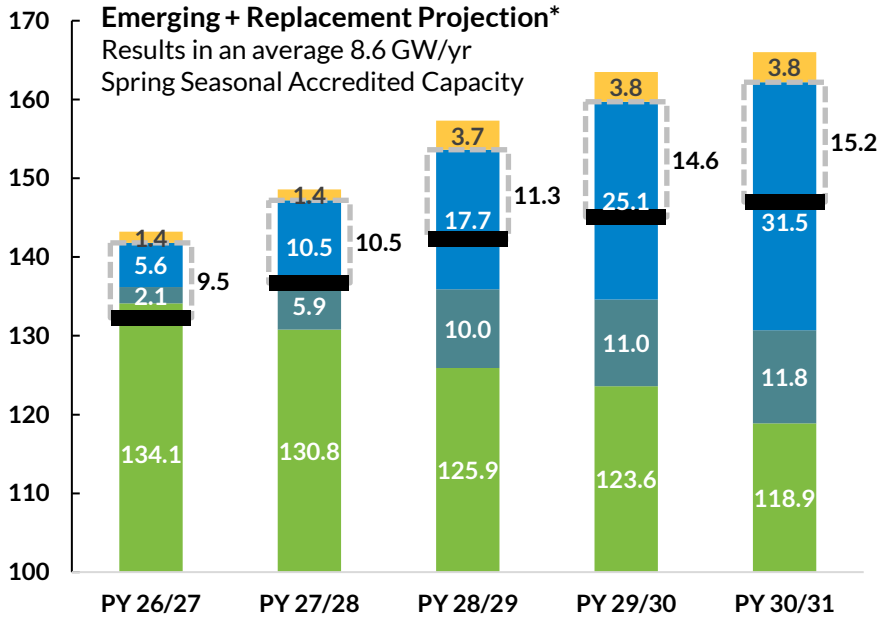
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Historical + Replacement & Emerging + Replacement Projections vs PRMR ~4.7 GW & 8.6 GW Status Quo Fall SAC Installation Rate

MISO Resource Adequacy Projection – Fall





Projected PRMR with LSE forecast
Potentially Unavailable Resources
Potential New Capacity
Value of Replacement/Surplus Projects
Committed Capacity

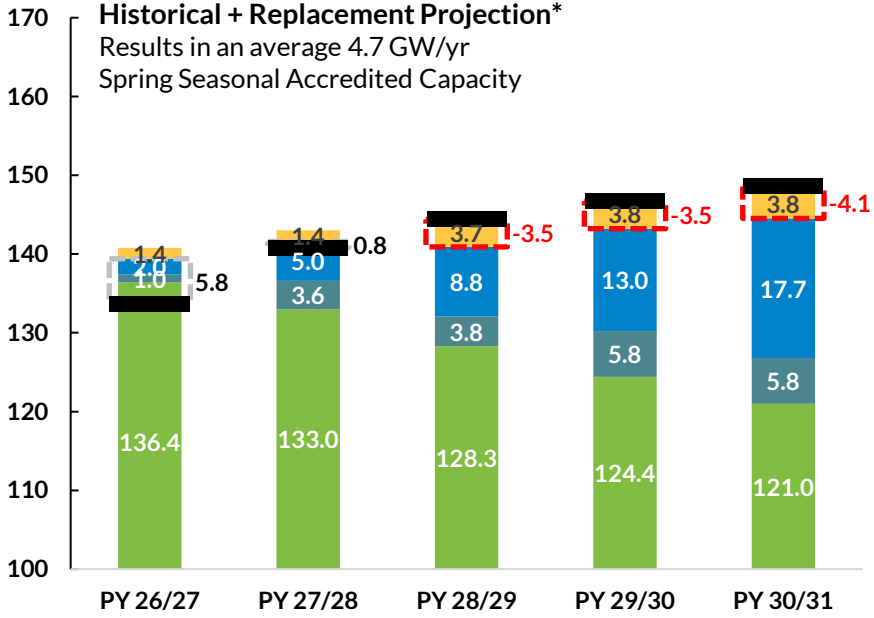
Using methods in line with potential New Capacity described on Slide 5
***PRMR:** Planning Reserve Margin Requirement*

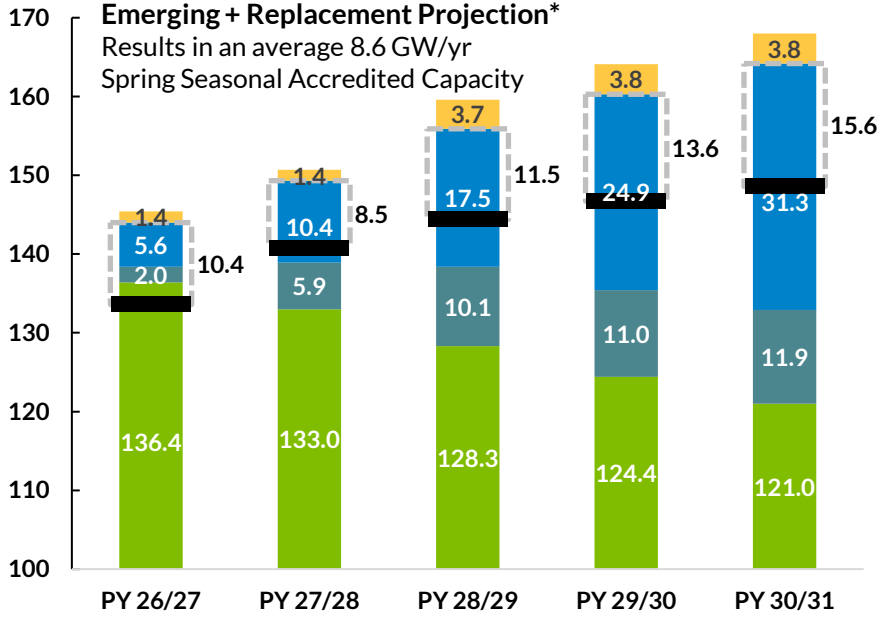
Red border values indicate the additional potential deficit against the Projected PRMR
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- Capacity accreditation values and Planning Reserve Margin projections based on current practices
- Regional Directional Transfer (RDT) limit of 1900 MW is reflected in this chart

Historical + Replacement & Emerging + Replacement Projections vs PRMR ~4.7 GW & 8.6 GW Status Quo Spring SAC Installation Rate

MISO Resource Adequacy Projection – Spring





Projected PRMR with LSE forecast
Potentially Unavailable Resources
Potential New Capacity
Value of Replacement/Surplus Projects
Committed Capacity

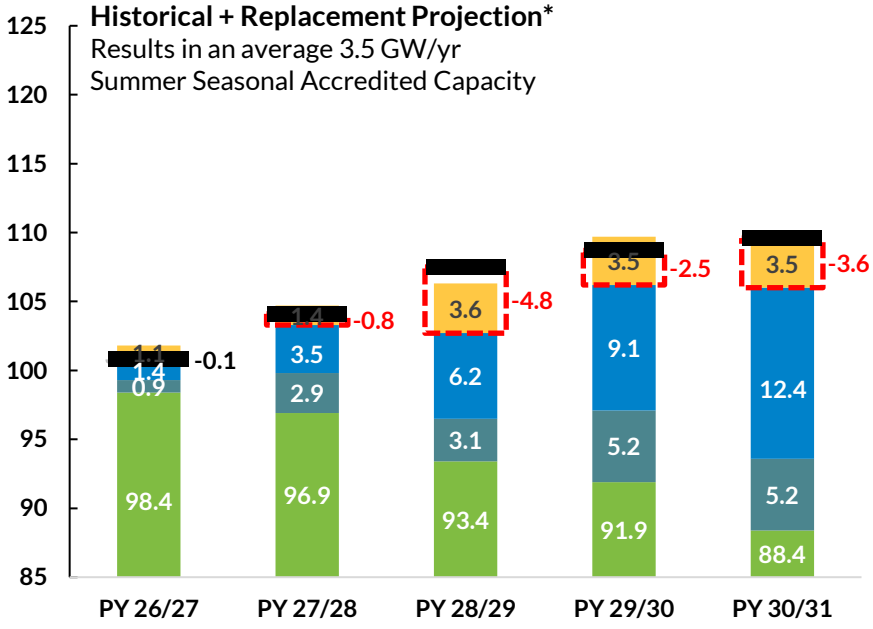
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***PRMR:** Planning Reserve Margin Requirement*

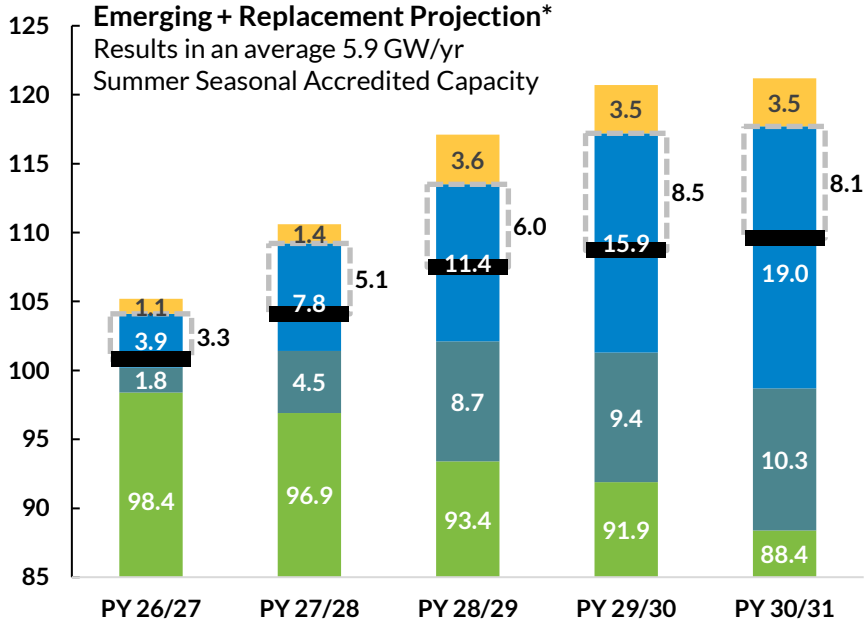
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- Capacity accreditation values and Planning Reserve Margin projections based on current practices
- Regional Directional Transfer (RDT) limit of 1900 MW is reflected in this chart

Historical + Replacement & Emerging + Replacement Projections vs PRMR ~4.7 GW & 8.6 GW Status Quo Summer SAC Installation Rate

MISO Resource Adequacy Projections – Summer MISO North/Central





Projected PRMR with LSE forecast
Potentially Unavailable Resources
Potential New Capacity
Value of Replacement/Surplus Projects
Committed Capacity

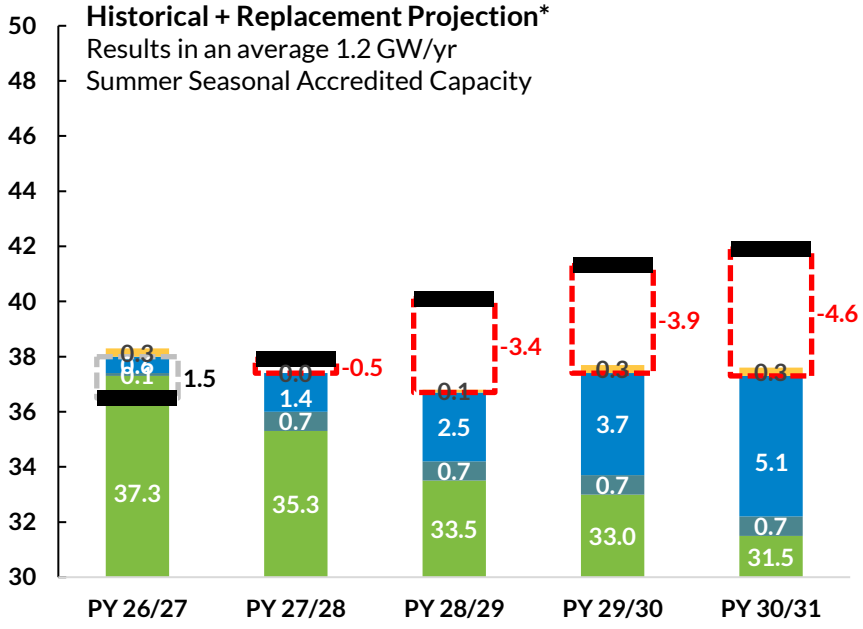
Using methods for potential New Capacity described on Slide 5
***PRMR:** Planning Reserve Margin Requirement*

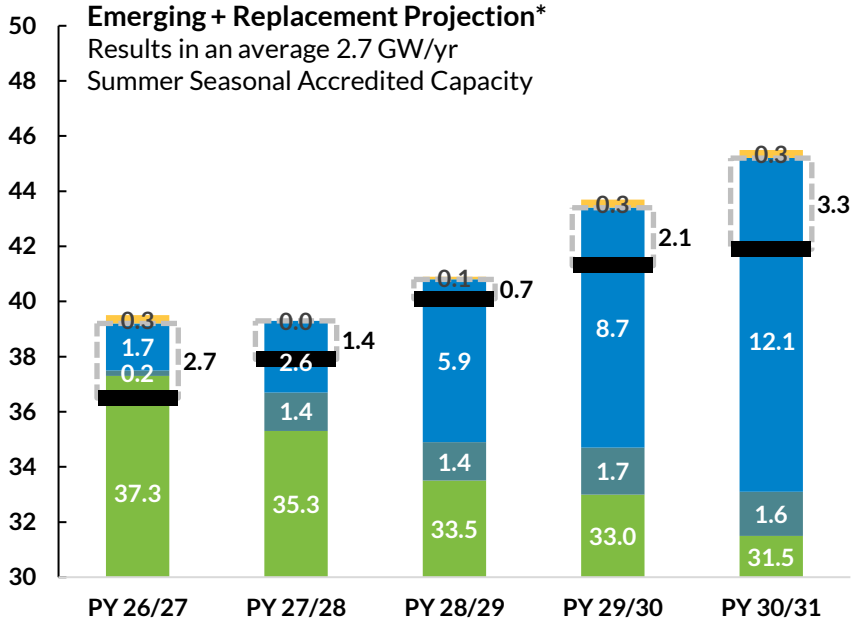
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Historical + Replacement & Emerging + Replacement Projections vs PRMR ~4.7 GW & 8.6 GW Status Quo Summer SAC Installation Rate

MISO Resource Adequacy Projections – Summer MISO South





- Projected PRMR with LSE forecast
- Potentially Unavailable Resources
- Potential New Capacity
- Value of Replacement/Surplus Projects
- Committed Capacity

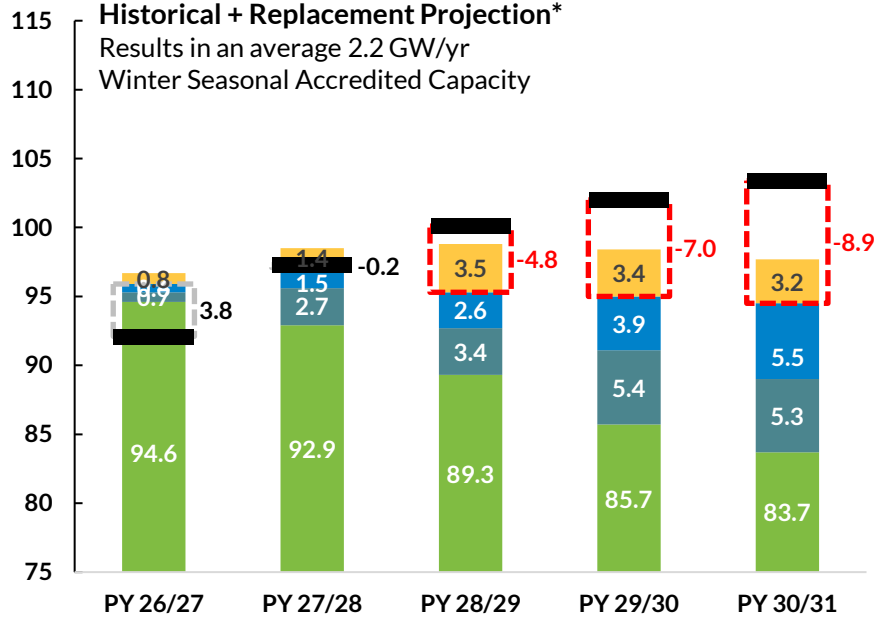
Using methods for potential New Capacity described on Slide 5

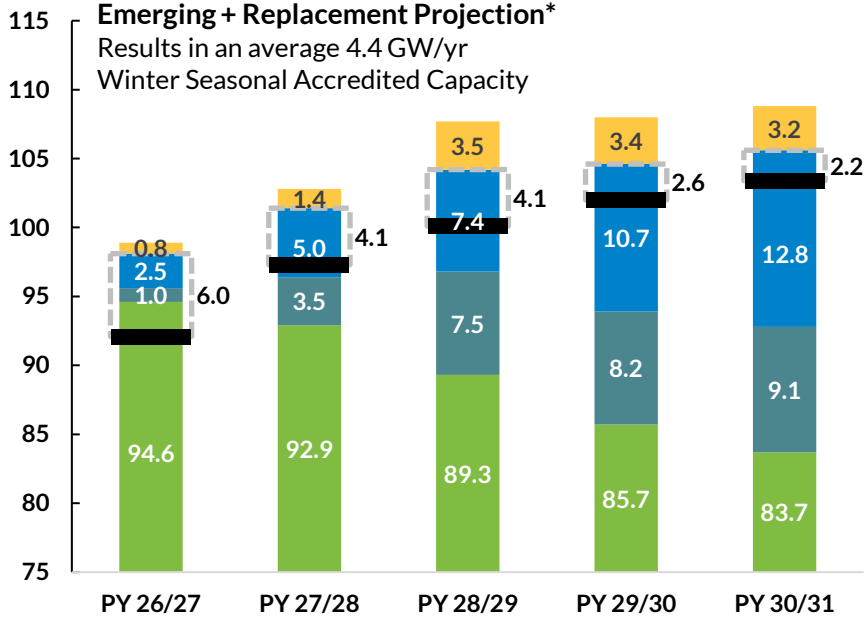
***PRMR:** Planning Reserve Margin Requirement*

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- Capacity accreditation values and Planning Reserve Margin projections based on current practices
- Regional Directional Transfer (RDT) limit of 1900 MW is reflected in this chart

Historical + Replacement & Emerging + Replacement Projections vs PRMR ~2.4 GW & 6.2 GW Status Quo Winter SAC Installation Rate

MISO Resource Adequacy Projections – Winter MISO North/Central





Projected PRMR with LSE forecast
Potentially Unavailable Resources
Potential New Capacity
Value of Replacement/Surplus Projects
Committed Capacity

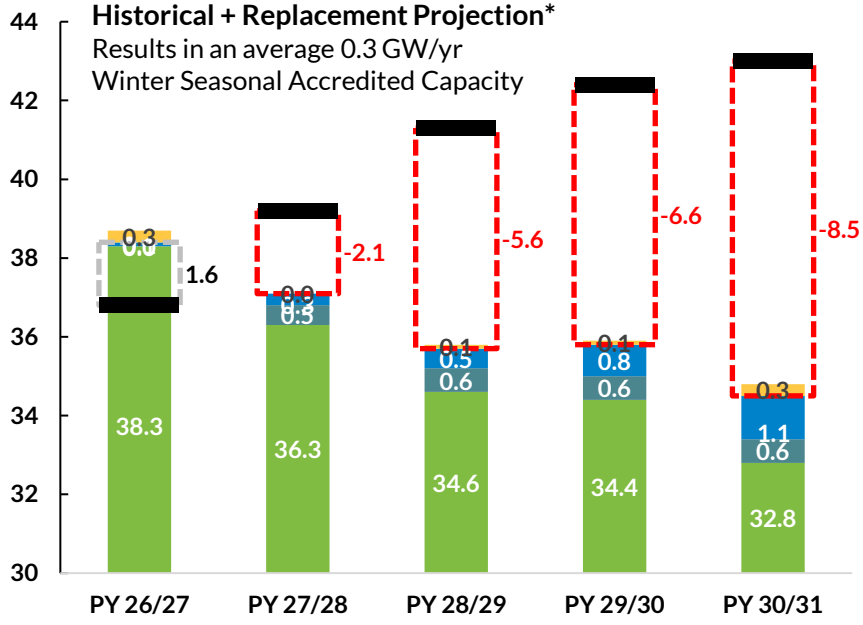
Using methods for potential New Capacity described on Slide 8
***PRMR:** Planning Reserve Margin Requirement*

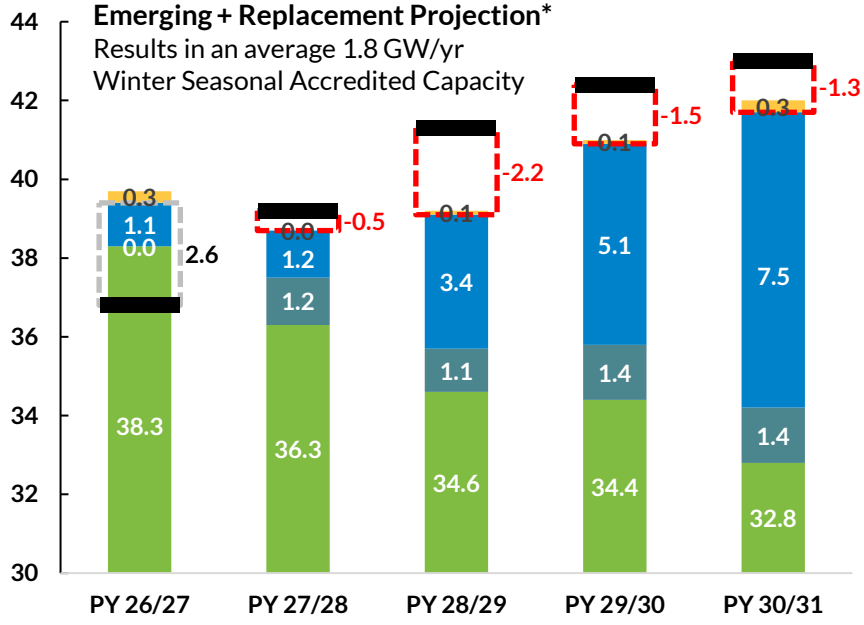
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- Regional Directional Transfer (RDT) limit of 1900 MW is reflected in this chart

Historical + Replacement & Emerging + Replacement Projections vs PRMR ~2.4 GW & 6.2 GW Status Quo Winter SAC Installation Rate

MISO Resource Adequacy Projections – Winter MISO South





Projected PRMR with LSE forecast
Potentially Unavailable Resources
Potential New Capacity
Value of Replacement/Surplus Projects
Committed Capacity

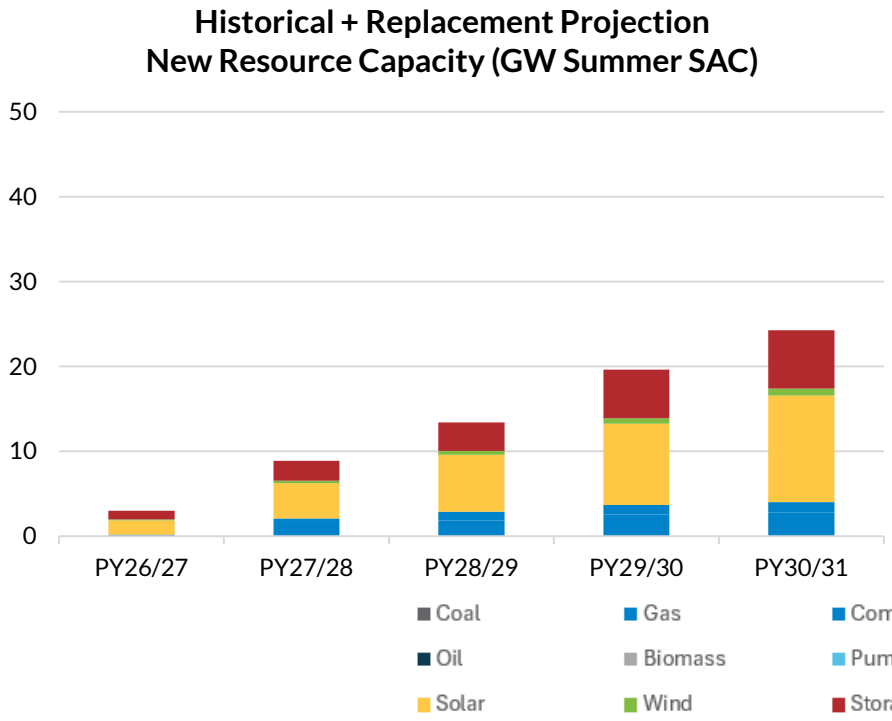
Using methods for potential New Capacity described on Slide 8
***PRMR:** Planning Reserve Margin Requirement*

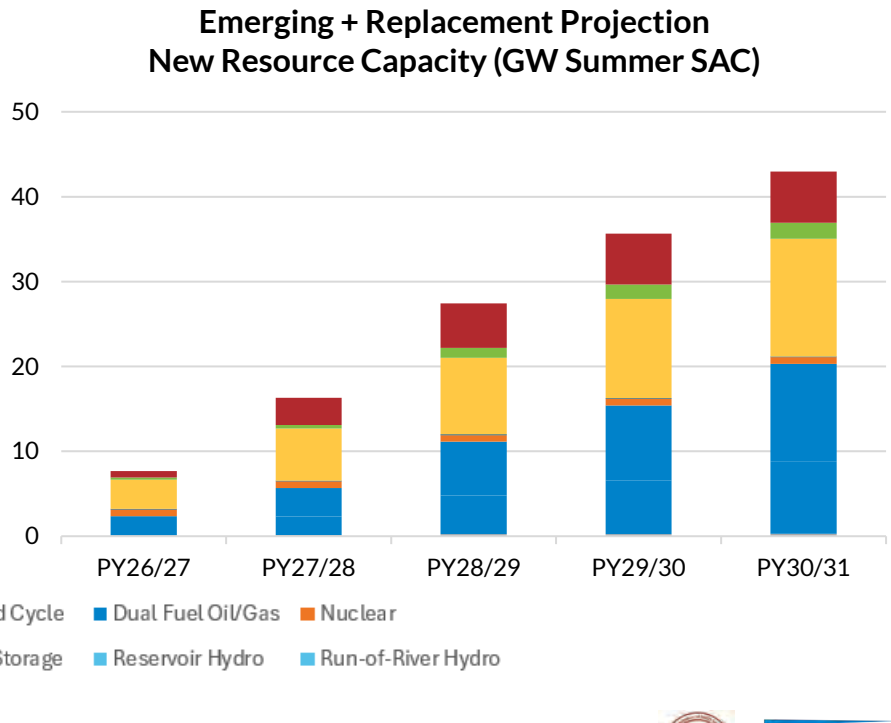
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OMS-MISO Survey projections of new resource accreditation value -Status Quo SAC calculations

Projections of New Resource Fuel Mix – Summer



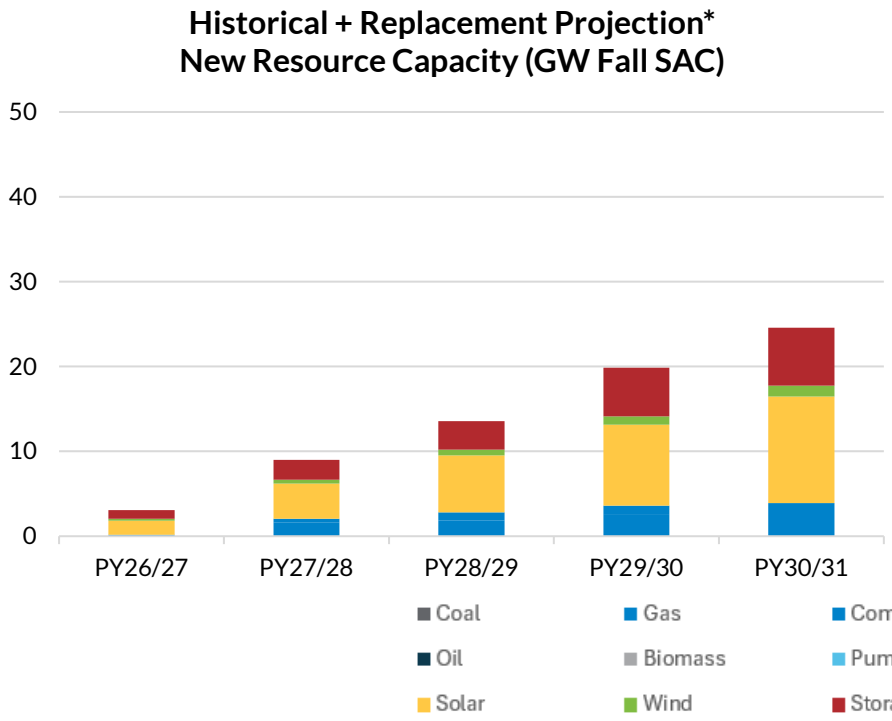


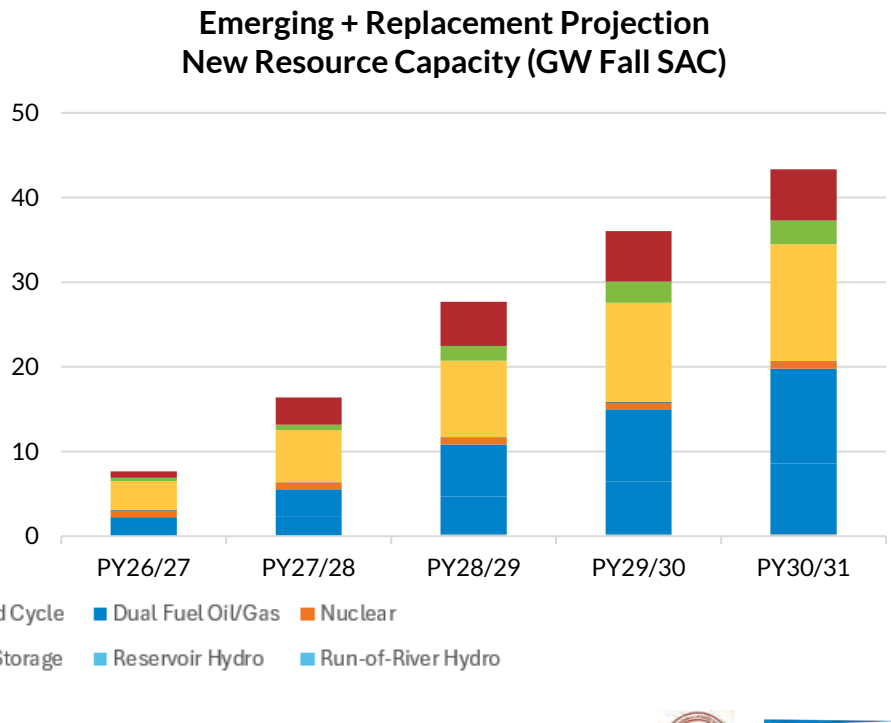
Coal | Gas | Combined Cycle | Dual Fuel Oil/Gas | Nuclear
Oil | Biomass | Pumped Storage | Reservoir Hydro | Run-of-River Hydro
Solar | Wind | Storage

SAC: *Seasonal Accredited Capacity*
All values are cumulative, and are based upon average fuel type resource accreditation from Planning Year 2025/26

OMS-MISO Survey projections of new resource accreditation value -Status Quo SAC calculations

Projections of New Resource Fuel Mix – Fall



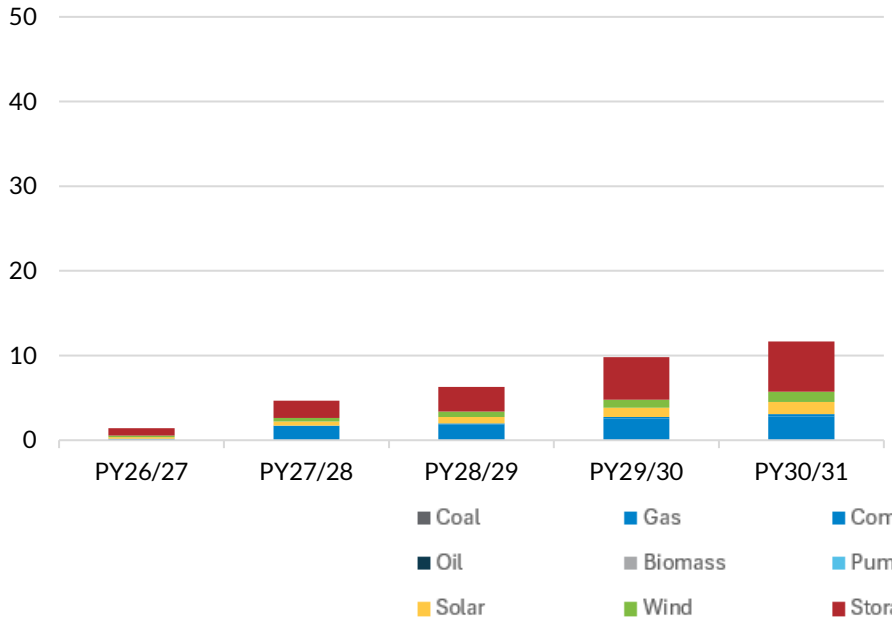


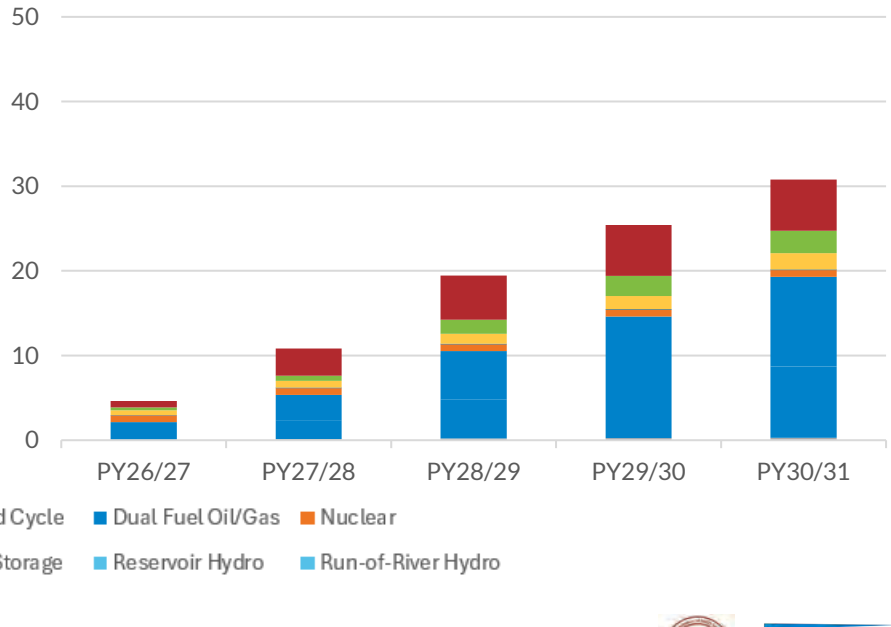
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OMS-MISO Survey projections of new resource accreditation value -Status Quo SAC calculations

Projections of New Resource Fuel Mix – Winter



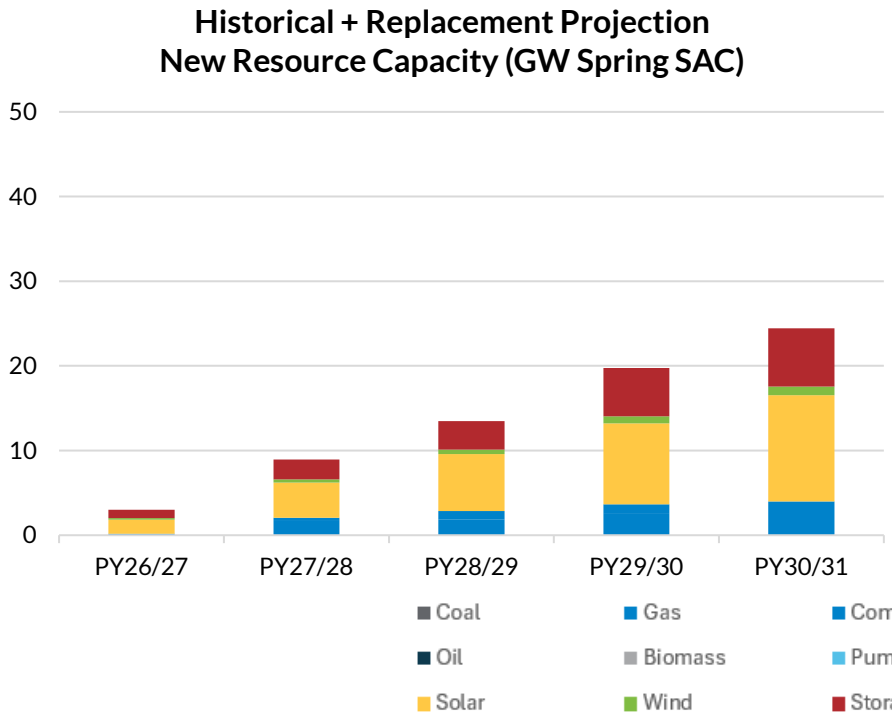


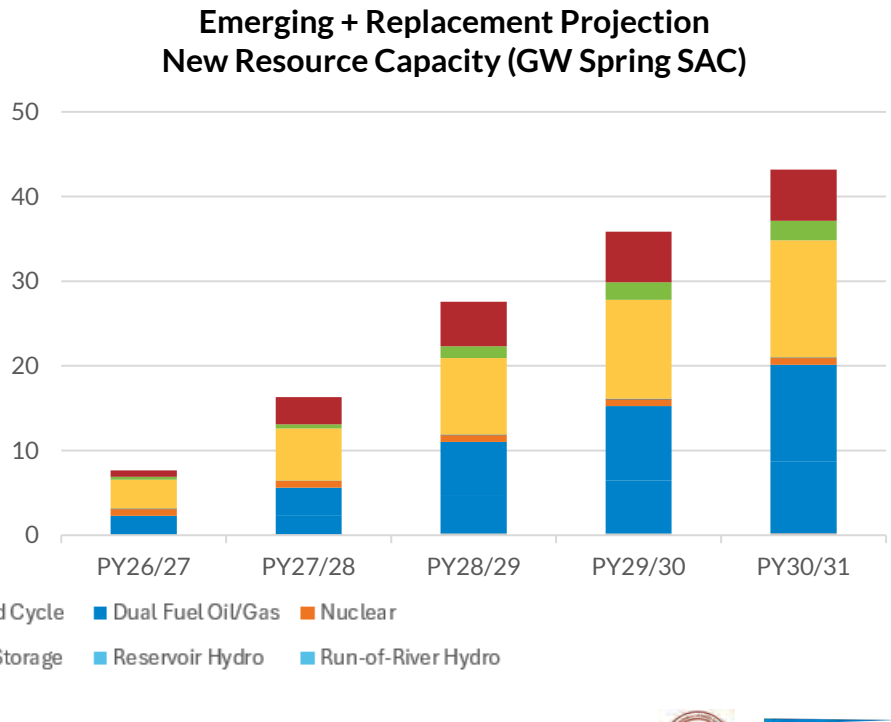
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OMS-MISO Survey projections of new resource accreditation value -Status Quo SAC calculations

Projections of New Resource Fuel Mix – Spring



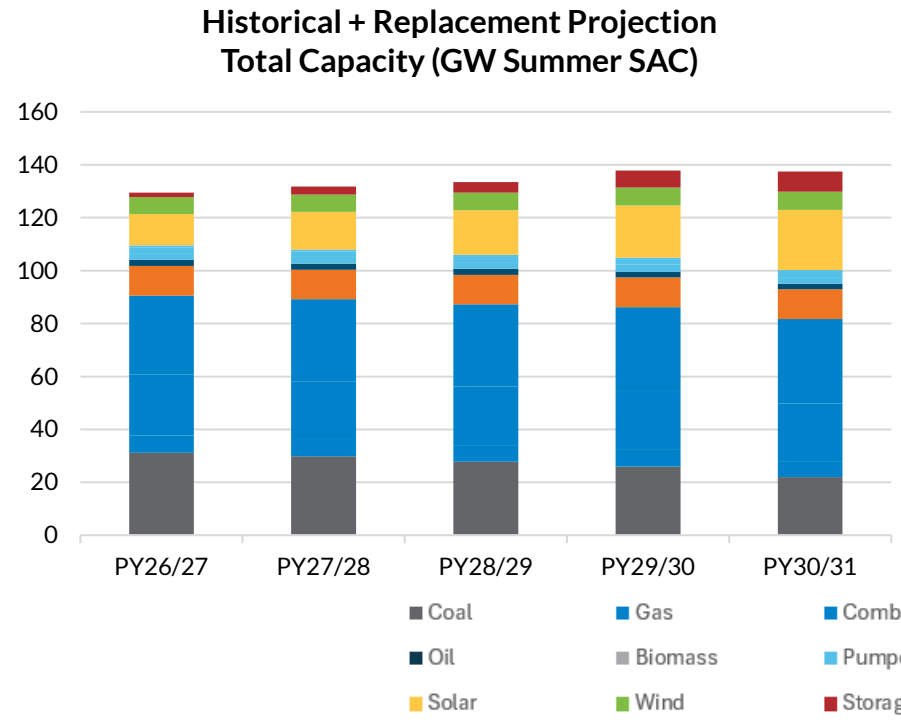


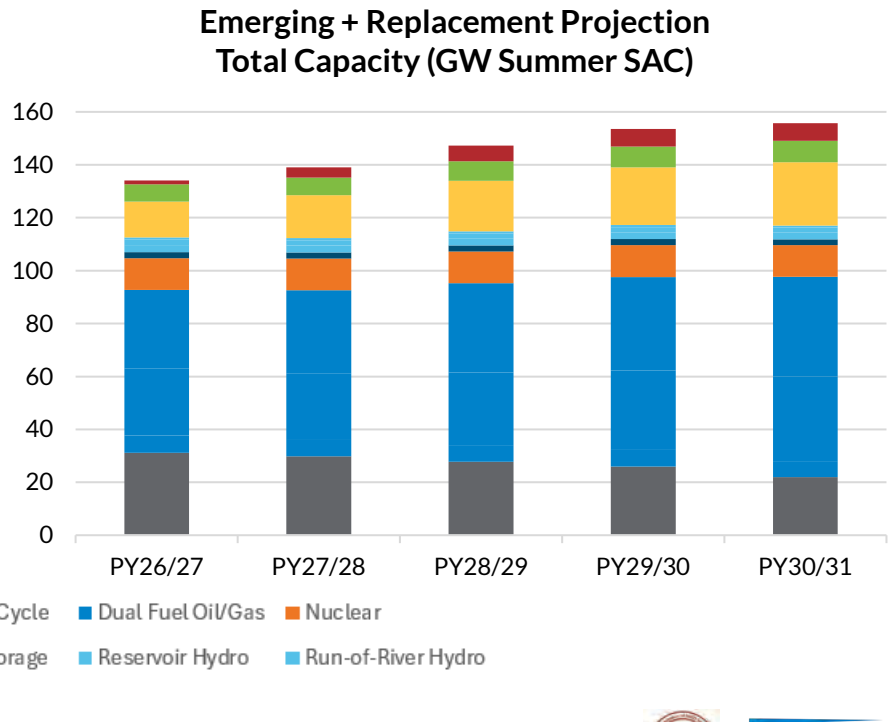
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OMS-MISO Survey projections of fleet total resource accreditation value -Status Quo SAC calculations

Combined Projections of Fuel Mix – Summer



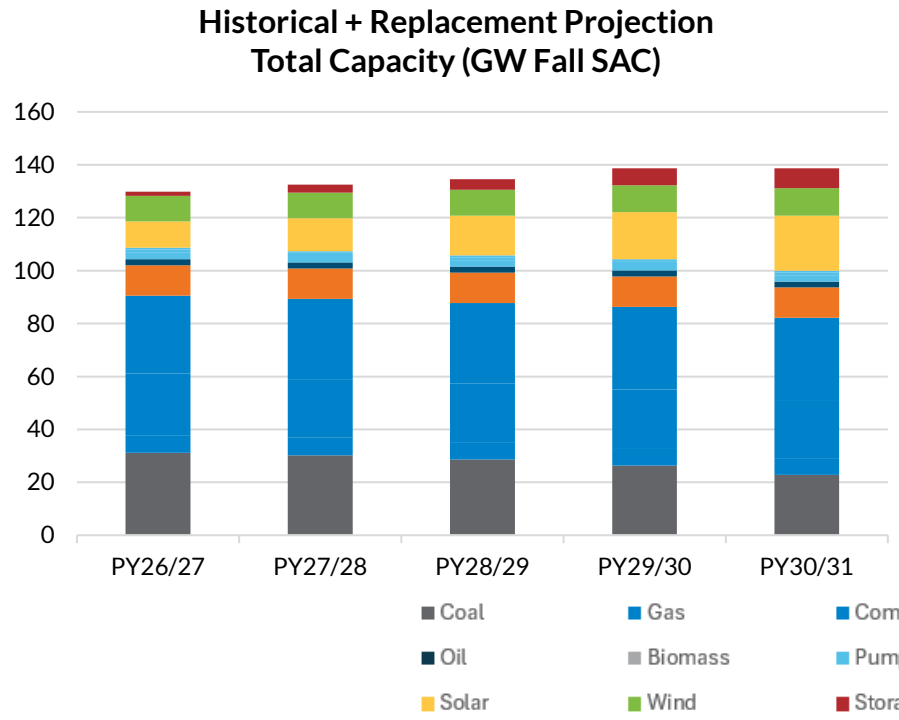


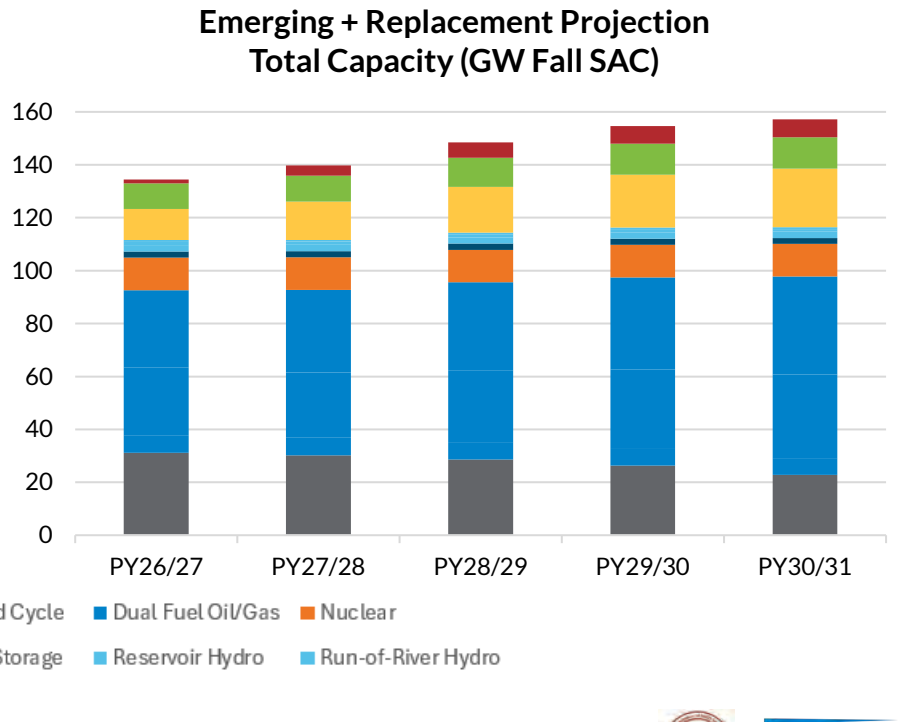
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SAC: *Seasonal Accredited Capacity*
New resources are based upon average fuel type resource accreditation from Planning Year 2025/26, existing based on seasonal Status Quo SAC

OMS-MISO Survey projections of fleet total resource accreditation value -Status Quo SAC calculations

Combined Projections of Fuel Mix – Fall



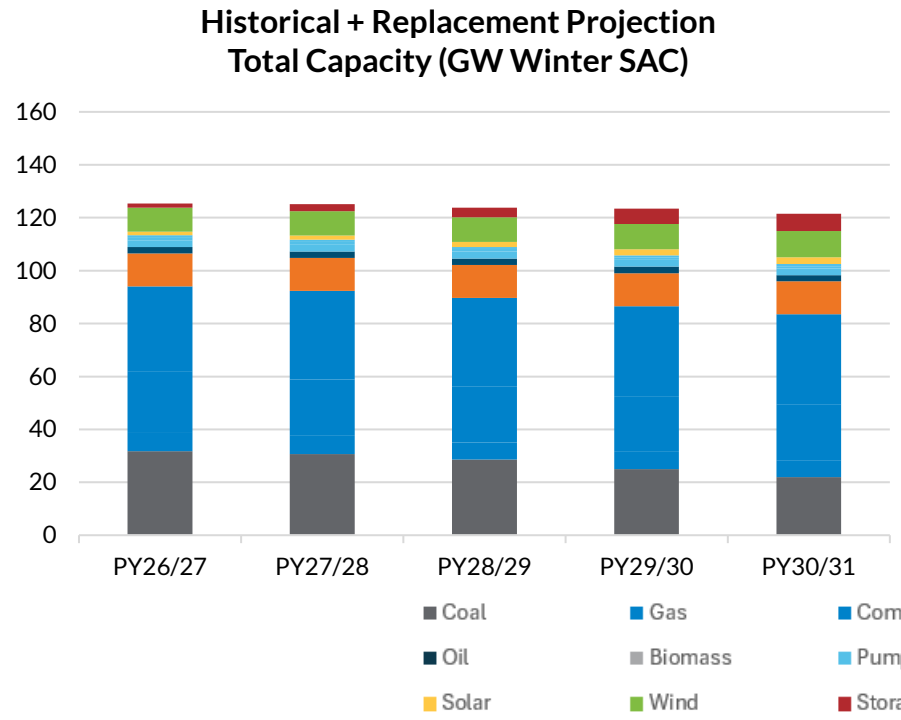


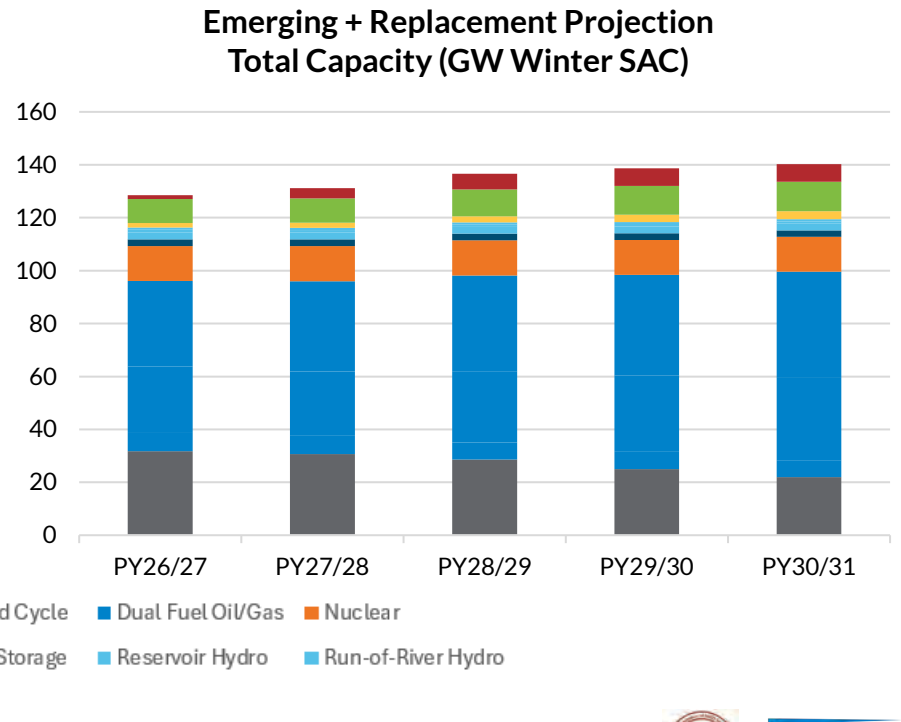
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OMS-MISO Survey projections of fleet total resource accreditation value -Status Quo SAC calculations

Combined Projections of Fuel Mix – Winter





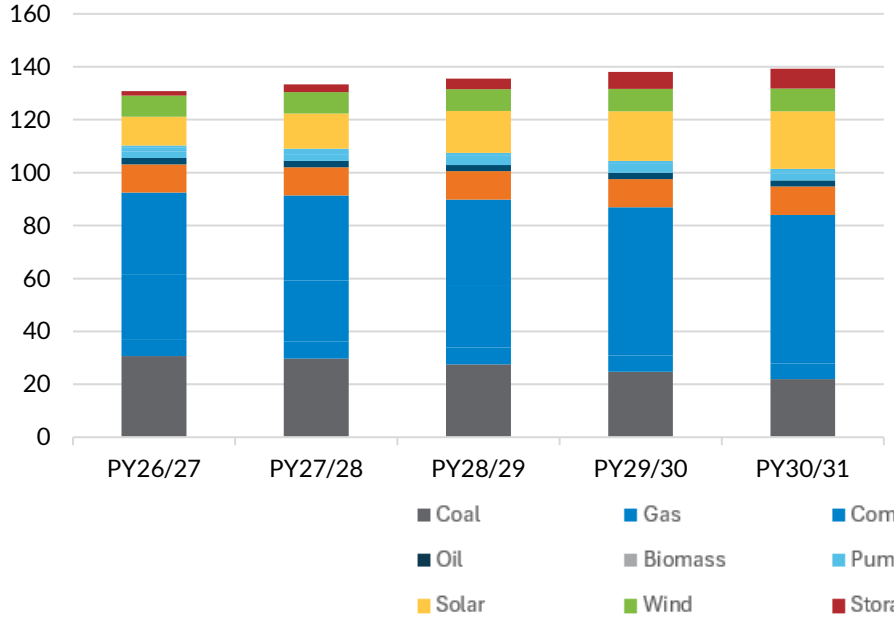
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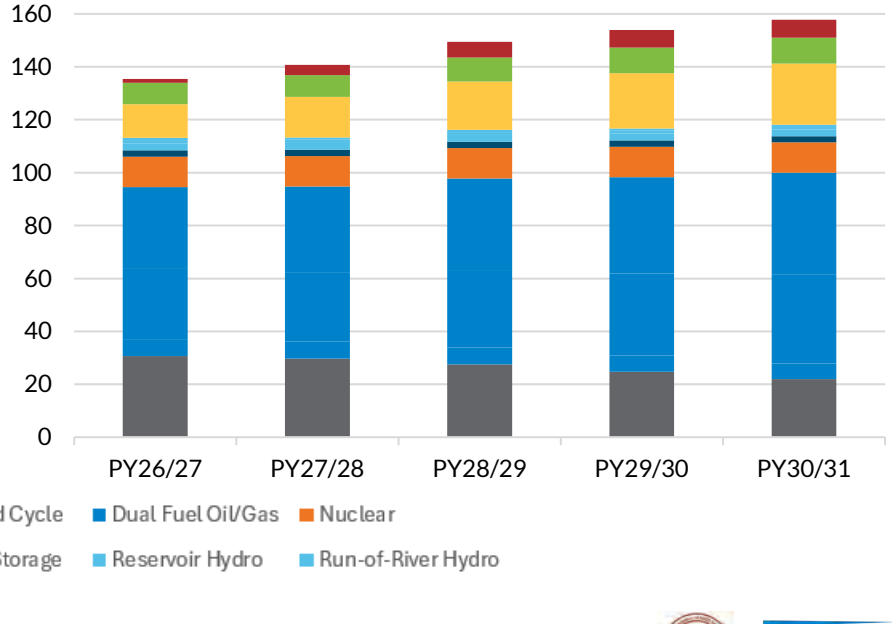
OMS-MISO Survey projections of fleet total resource accreditation value -Status Quo SAC calculations

Combined Projections of Fuel Mix – Spring

Historical + Replacement Projection
Total Capacity (GW Spring SAC)



Emerging + Replacement Projection
Total Capacity (GW Spring SAC)

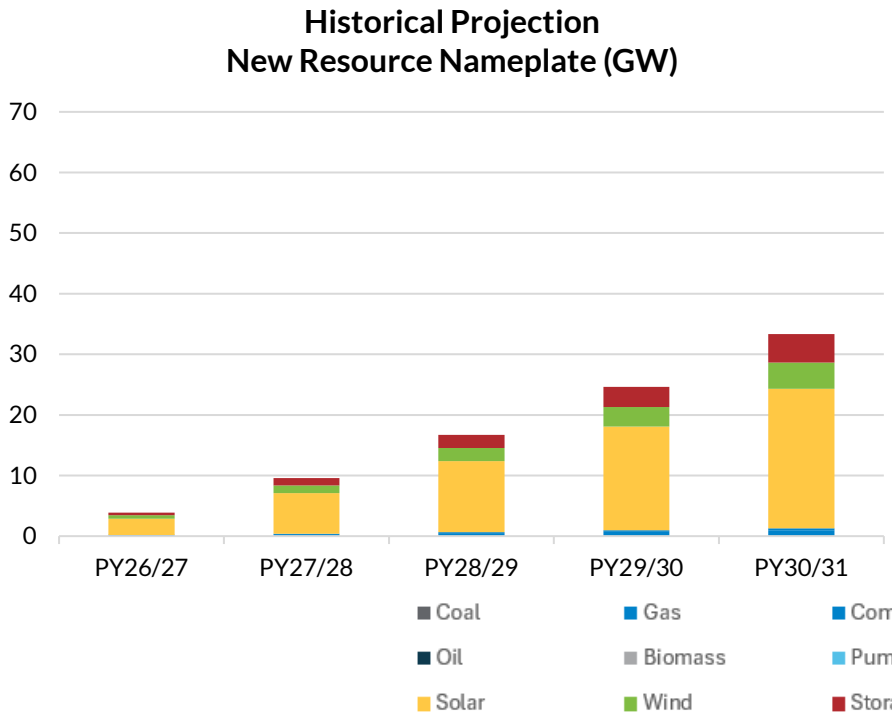


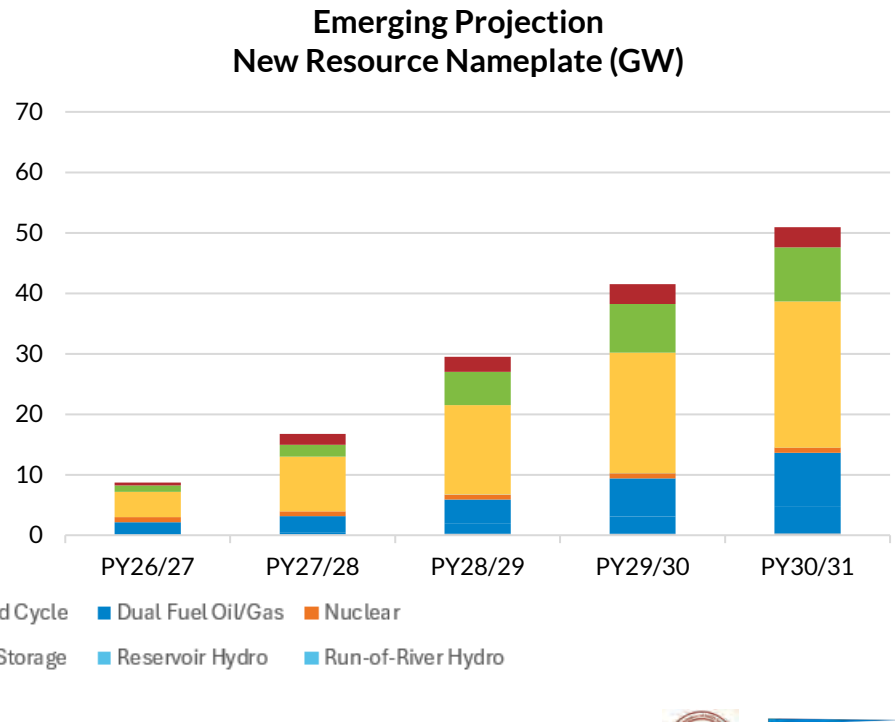
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SAC: *Seasonal Accredited Capacity*
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OMS-MISO Survey projections of new resource deliverable nameplate

Combined Projections of Fuel Mix, New Resource Nameplate Only (ICAP)



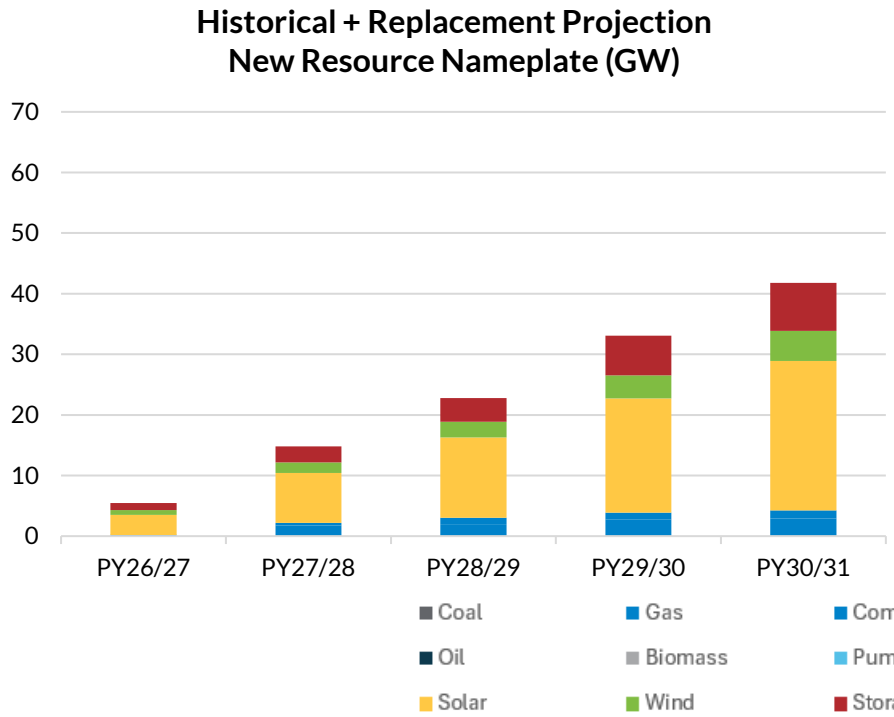


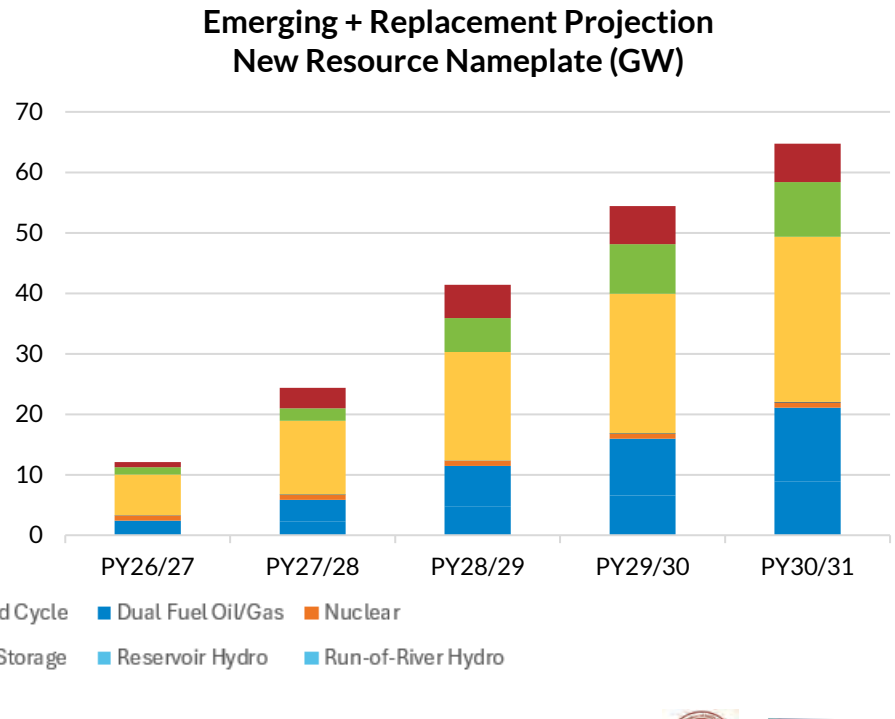
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Oil | Biomass | Pumped Storage | Reservoir Hydro | Run-of-River Hydro
Solar | Wind | Storage

ICAP: *Installed Capacity*
All values are cumulative, and are based on projected nameplate installation for each fuel type

OMS-MISO Survey projections of new resource deliverable nameplate

Combined Projections of Fuel Mix, New Resource Nameplate Only (ICAP)



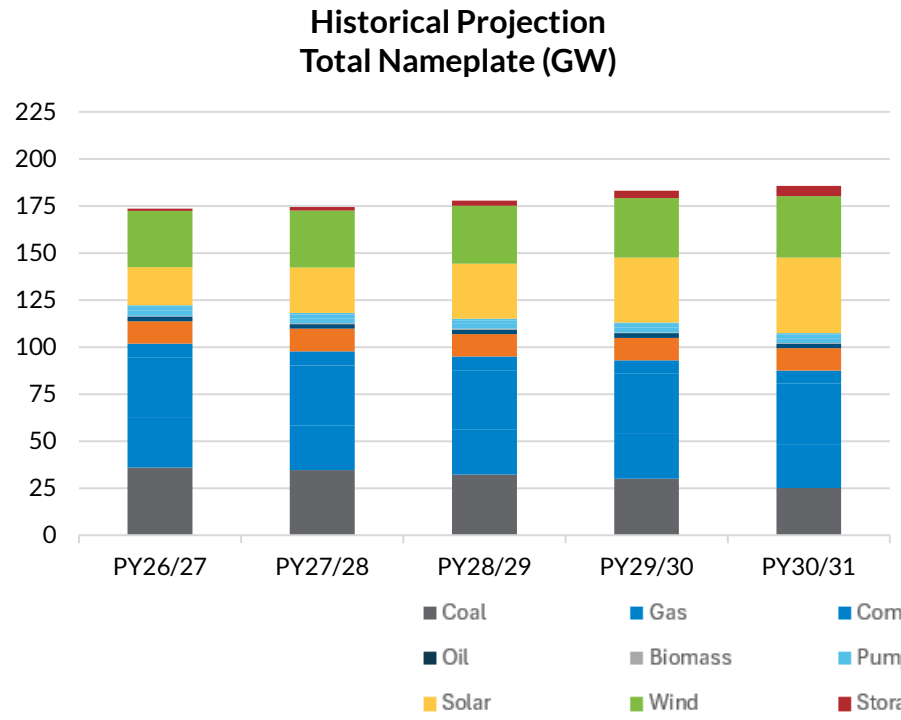


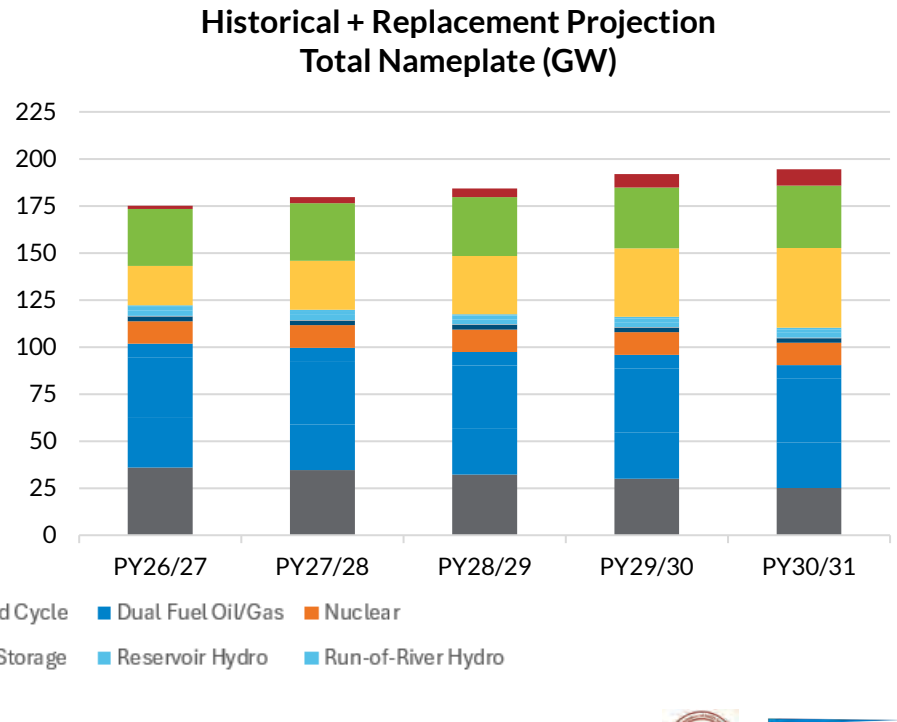
Coal | Gas | Combined Cycle | Dual Fuel Oil/Gas | Nuclear
Oil | Biomass | Pumped Storage | Reservoir Hydro | Run-of-River Hydro
Solar | Wind | Storage

ICAP: *Installed Capacity*
All values are cumulative, and are based on projected nameplate installation for each fuel type

OMS-MISO Survey projections of fleet total deliverable nameplate

Combined Projections of Fuel Mix, Fleet Composition by Nameplate (ICAP)



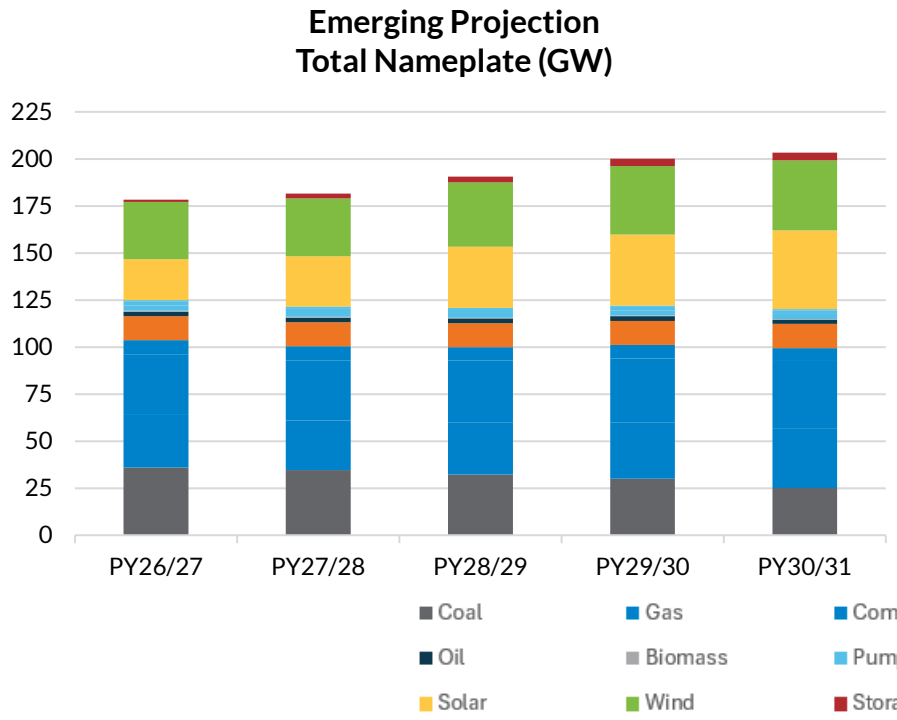


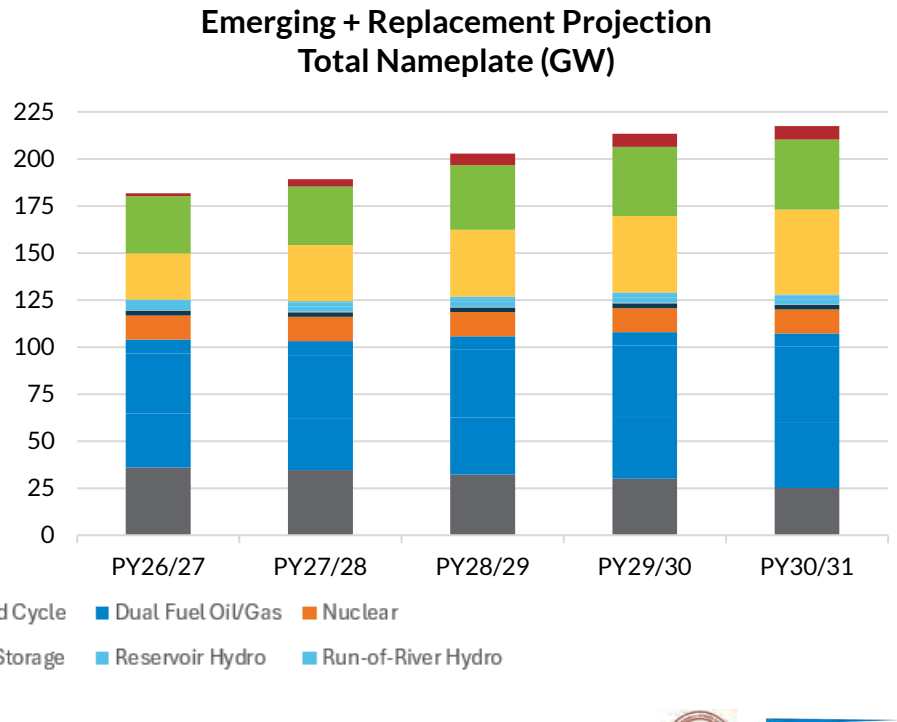
Coal | Gas | Combined Cycle | Dual Fuel Oil/Gas | Nuclear
Oil | Biomass | Pumped Storage | Reservoir Hydro | Run-of-River Hydro
Solar | Wind | Storage

ICAP: *Installed Capacity*

OMS-MISO Survey projections of fleet total deliverable nameplate

Combined Projections of Fuel Mix, Fleet Composition by Nameplate (ICAP)





ICAP: *Installed Capacity*

BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-25-12
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	))))	Order No. 202-25-13

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

Exhibit 90
MISO ERAS Transmittal Letter

Sarah Nieman
Associate Corporate Counsel
Direct Dial: 317-549-0041
Email: sanieman@misoenergy.org

June 6, 2025

VIA ELECTRONIC FILING

The Honorable Debbie-Anne A. Reese
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: Midcontinent Independent System Operator, Inc.
Revisions to the Open Access Transmission, Energy and Operating Reserve Tariff
Expedited Resource Addition Study Filing
Docket No. ER25-____-000

Dear Secretary Reese:

The Midcontinent Independent System Operator, Inc. ("MISO") submits this filing[1] to revise its Open Access Transmission, Energy and Operating Reserve Markets Tariff ("Tariff")[2] to amend its Attachment X, Generator Interconnection Procedures ("GIP").[3] MISO is grateful for the Commission's feedback on its previous ERAS proposal and for identifying the concerns it had with MISO's proposal.[4] MISO has taken this feedback and refined its original ERAS proposal to address these concerns and others that were shared by stakeholders. MISO now proposes a refined Expedited Resource Addition Study ("ERAS") process that addresses the concerns identified by the Commission and provides an improved framework for the accelerated study of generation projects that can address urgent resource adequacy and reliability needs in the near term.

This filing includes the authority and applicable procedures to implement the refined ERAS process, including how Interconnection Customers claim a new Interconnection Request will meet

[1] MISO makes this filing pursuant to Section 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d, and Part 35 of the regulations of the Federal Energy Regulatory Commission ("FERC" or "Commission"), 18 C.F.R. § 35.1, *et seq*.

[2] All capitalized terms not otherwise defined herein shall have the meaning as set forth in the Tariff or the proposed revisions, as applicable.

[3] The GIP are set forth in Attachment X of the Tariff.

[4] *See Midcontinent Independent System Operator, Inc.*, 191 FERC ¶ 61,131 at P 203 (2025) ("ERAS Order").

a resource adequacy and/or reliability need and how the Relevant Electric Retail Regulatory Authority ("RERRA")[5] will submit a verification to MISO that states either: (i) the new, incremental load addition claimed by the Interconnection Customer is valid and not otherwise included in a resource plan or other process under the RERRA's purview or (ii) that the Generating Facility will address a resource adequacy deficiency. As the Commission recognized in the ERAS Order, "it is appropriate for RERRAs to communicate to MISO their resource adequacy and reliability needs, as well as their support for including interconnection requests in the ERAS process, to ensure that the RERRA's needs are met in a timely fashion."[6] Moreover, the Federal Power Act ("FPA") and FERC precedent both recognize the exclusive authority of state regulators and their jurisdictional utilities to plan for adequate generation resources to address resource adequacy needs within their jurisdictional footprints.[7] ERAS responds to this authority and current needs. It enables the timely development of generation that must be online in the near term to address claimed resource adequacy and/or reliability needs—needs for which the current processing time of MISO's queue presents a barrier to solution availability.

ERAS also complements the recent submittals implementing a proposed cap in the queue as well as other improvements to the GIP including increased milestone payments, withdrawal penalty requirements, and Site Control rules.[8] The Cap and GIP Improvement proposals were focused on longer-term improvements to the queue, while ERAS is focused on short-term improvements that will facilitate the addition of necessary resources in the MISO footprint. MISO has made refinements to its original ERAS proposal to include a total project cap and to structure this cap in a way that accommodates the needs of retail choice states and independent power producers ("IPPs"). MISO has also added several requirements to promote a tighter connection between proposed ERAS projects and the resource adequacy needs that the projects will address. The supporting evidence convincingly demonstrates that the refined ERAS process will provide the expedited path forward to bring projects online to meet near-term needs and will address certain challenges posed by the rapidly growing size of the queue.[9]

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5 A RERRA is defined as "[a]n entity that has jurisdiction over and establishes prices and/or policies for providers of retail electric service to end-customers, such as the city council for a municipal utility, the governing board of a cooperative utility, the state public utility commission or any other such entity." MISO, FERC Electric Tariff, Module A, § 1.R (72.0.0).

6 ERAS Order at P 203.

7 16 U.S.C. § 824 (1976); FERC has recognized that state-federal "bifurcated framework respects the jurisdictional boundaries of the FPA while recognizing the states' historical role in ensuring resource adequacy." *Cxa La Paloma, LLC*, 165 FERC ¶ 61,148 at P 70 (2018).

8 *See Midcontinent Independent System Operator, Inc.*, 186 FERC ¶ 61,054 (2024); *Midcontinent Independent System Operator, Inc.*, "Revisions to the Open Access Transmission, Energy and Operating Reserve Tariff Queue Cap Proposal and Exemptions to the Queue Cap Proposal," Docket No. ER25-507-000 (November 21, 2024).

9 *See* Prepared Direct Testimony of Andrew Witmeier ("Witmeier Testimony"), attached at Tab C.

MISO requests an effective date of August 6, 2025, for this filing. Moreover, given this filing is built on a proposal already reviewed extensively by stakeholders and the Commission and is tailored to address the Commission's guidance, MISO requests the Commission issue an order on this filing expeditiously by July 22, 2025. The grant of this request, in light of the totality of the factors, is reasonable. It will also be limited to the instant request here to effectuate a needed process. Given the resource adequacy and reliability needs identified below, MISO needs to implement that process as soon as possible. An expedited order will afford Interconnection Customers the certainty needed to prepare their Interconnection Requests to submit for the first ERAS Quarterly Study Period, which starts on September 2, 2025. The additional two weeks will provide material value to Interconnection Customers. Additionally, to enable the Commission's expedited decision making, MISO requests that the Commission establish a ten-day comment period for this filing, with June 16, 2025, as the comment date.

MISO acknowledges the expedited action requested places pressure on stakeholders and the Commission alike. This expedited treatment will ensure that Interconnection Customers have sufficient time to prepare for ERAS and have certainty that the proposed changes can be implemented to bring the ERAS process into alignment with other standard MISO practices and processes and to ensure that it will be in place prior to the September 2, 2025 Quarterly Study Period kickoff date for ERAS.[10] Just as this filing has been turned in a matter of a few weeks since receiving the Commission's guidance in the ERAS Order, the time afforded to MISO and Interconnection Customers by two weeks, assuming Commission acceptance, is time well spent to move this proposed process forward effectively. The requested order and effective dates will ensure that the proposed changes are implemented to accelerate the study of projects to address the looming resource adequacy and reliability needs in the MISO footprint in the next few years.

I. EXECUTIVE SUMMARY

A. Summary of MISO's First ERAS Filing

On March 17, 2025, MISO submitted its original filing with proposed revisions to Attachment X in the MISO Tariff, to establish the 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.[11] MISO proposed that an ERAS Interconnection Request be required to demonstrate that it would meet an identified resource adequacy and/or reliability need by providing both: (1) a written notification from the RERRA that

[10] Witmeier Testimony at 7:6-10.

[11] *Midcontinent Independent System Operator, Inc.*, "Revisions to the Open Access Transmission, Energy and Operating Reserve Tariff Expedited Resource Addition Study Filing," Docket No. ER25-1674-000 (March 17, 2025) ("ERAS Transmittal Letter").

the project should be studied through ERAS; and (2) an executed agreement evidencing that the ERAS project was intended to be used by the entity with the claimed resource adequacy or reliability need. MISO also proposed that ERAS have strict eligibility requirements including: shorter commercial operation date (COD) requirements, greater (100%) site control requirements, higher application fee and milestone payments, and a requirement to pay for all network upgrades documented in the EGIA, even if the Interconnection Customer withdraws its request after the EGIA is executed or filed unexecuted with the Commission. Finally, MISO proposed that the original ERAS process would sunset by the end of 2028.

On May 16, the Commission issued an order rejecting MISO's proposed Tariff revisions and provided guidance on the proposed ERAS process.[12] The Commission found that MISO's ERAS proposal was not "a just and reasonable and not unduly discriminatory or preferential approach for addressing MISO's stated resource adequacy and reliability needs."[13] The Commission identified two issues with the ERAS framework: (1) that there was "no limit on the number of projects that could be entered into the ERAS process,"[14] and (2) "the proposal does not sufficiently describe how the ERAS process is sufficiently targeted to study only interconnection requests needed to meet the anticipated shortfall in generating capacity described by MISO."[15] The Commission also recognized that it was "appropriate for RERRAs to communicate to MISO their resource adequacy and reliability needs, as well as their support for including interconnection requests in the ERAS process, to ensure that the RERRA's needs are met in a timely fashion."[16] Each of the Commissioners also filed individual statements urging MISO to revise and refile its ERAS proposal.[17]

MISO is grateful for the Commission's guidance on how to better craft its ERAS proposal and appreciates the recommendations made within the order. MISO has worked swiftly to develop a refined ERAS process tailored to address the Commission's concerns, other issues raised by stakeholders, and one that can withstand legal review. MISO is now proposing a refined ERAS process that can be implemented by September 2, 2025 to quickly address the looming resource adequacy and reliability needs that it highlighted in its original ERAS filing.

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[12] ERAS Order at P 1.

[13] *Id.* at P 197.

[14] *Id.* at P 199.

[15] *Id.* at P 201.

[16] *Id.* at P 203.

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

B. Growing Resource Adequacy Concerns

The energy industry continues to change rapidly. Urgent resource adequacy and reliability challenges are arising because of continued electrification efforts, a resurgence in manufacturing, an unexpected demand for energy-hungry data centers to support artificial intelligence, the growing preference for low or no carbon emission resources, and the accelerated early retirement of generation.[18] These combined factors are driving resource adequacy and reliability concerns across the country and are resulting in a complex policy landscape. Additional changes and improvements must be made to MISO's processes to enable it to meet these urgent and important needs.

Several surveys and forecasts offer perspectives demonstrating the urgency for MISO to address significant resource adequacy needs in its footprint that are compounded by the addition of unexpected large spot loads. First, MISO's Reliability Imperative Report explained, "[i]n light of the urgent and complex risks to electric reliability in the MISO region, utilities, states and MISO must all act with more urgency and more coordination to avoid a looming mismatch between the pace of adding new resources and the retirement of older resources in the MISO region."[19]

MISO also works with the Organization of MISO States ("OMS") to produce the OMS-MISO Survey which in 2024 "reinforce[d] near-term risks and highlights key uncertainties impacting resource adequacy in the MISO region," and also "illustrate[d] a strong sensitivity to the pace of new capacity additions."[20] The 2025 OMS-MISO Survey will be published on the same day as this filing and further "reinforces near-term risks and highlights key uncertainties impacting resource adequacy."[21] In fact, one of the key takeaways from the 2025 survey is that

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[18] MISO recently highlighted how "[t]he expansion of data centers, fueled by AI and cloud-based applications, will raise MISO's energy demand by 149-241 TWh by 2044", "the growth of EVs, driven by federal incentives and declining battery costs, is projected to add 54-91 TWh of demand by 2044, with rapid adoption between 2030-2040", "the electrification of oil and gas industries and reshoring efforts are expected to increase energy demand by 21-105 TWh by 2044", and how "federal and state policies are driving electrification of heating systems and appliances, increasing energy demand by 36-43 TWh by 2044." Long-Term Load Forecast, at 4, December 2024, available at:https://cdn.misoenergy.org/MISO%20Long-Term%20Load%20Forecast%20Whitepaper_December%202024667166.pdf.

[19] *See MISO's Response to the Reliability Imperative* (updated January 2023), available at: https://cdn.misoenergy.org/MISO%20Response%20to%20the%20Reliability%20Imperative504018.pdf.

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

[21] *Id.* at 2.

"[r]esource adequacy risk is intensifying."[22] Similarly, NERC's 2024 Long-Term Reliability Assessment projected that MISO will experience a 4.7 GW shortfall by 2028 if the current expected generator retirements occur.[23] NERC explained that MISO's resource additions were not keeping up with generator retirements and demand growth. As a result, NERC designated MISO's footprint as "high risk" for falling below established resource adequacy criteria in the next five years.[24] Collectively, these surveys and forecasts demonstrate that MISO *must* address resource adequacy and reliability needs in the next five years and that an accelerated interconnection study process must be established to address time-critical challenges. Compounding these generation challenges is the surge in load growth described above coming from economic development, a resurgence in manufacturing, increasing electrification, and data centers and other large load additions. As the Commission Staff's 2025 Summer Assessment stated: "Currently, the size and speed with which data centers and crypto mining facilities can be constructed and connect to the grid presents unique challenges for demand forecasting and planning. This increase in demand is currently challenging utilities to accelerate infrastructure upgrades and energy resource deployment and to reconsider scheduled resource retirements to maintain grid reliability."[25] As highlighted in MISO's presentation to the System Planning Committee of the MISO Board of Directors, MISO is indeed seeing a significant increase in load growth as well as transmission projects related to load growth over the last year, further evidencing growing demand and challenges in the MISO region.[26] Finally, FERC staff's recent 2025 Summer Assessment found possible reliability challenges in several RTO regions including MISO during extreme summer conditions.[27]

C. Summary of the ERAS Process

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[22] *2025 OMS-MISO Resource Adequacy Survey Results*, Fact Sheet, available at: https://cdn.misoenergy.org/2025%20OMS-MISO%20Survey%20Fact%20Sheet702641.pdf.

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

[24] *Id.* at 6.

[25] *2025 Summer Energy Market and Electric Reliability Assessment*, May 15, 2025, https://www.ferc.gov/news-events/news/ferc-releases-2025-summer-assessment.

[26] *Reliability Imperative: Transmission Evolution*, System Planning Committee of the Board of Director at 6-7, June 10, 2025, https://cdn.misoenergy.org/20250610%20System%20Planning%20Committee%20of%20the%20BOD%20Item%2005%20Reliability%20Imperative_Transmission%20Evolution701586.pdf.

[27] *2025 Summer Energy Market and Electric Reliability Assessment*, May 15, 2025, https://www.ferc.gov/news-events/news/ferc-releases-2025-summer-assessment.

While developing the original ERAS, MISO engaged with stakeholders on a regular basis to solicit feedback and to discuss suggested changes to the proposal. As described in more detail below, MISO participated in numerous meetings with stakeholders including official committee meetings, ERAS-specific workshops, and small-group meetings with individual stakeholder groups. Based on stakeholder feedback obtained from these meetings and discussions, MISO made significant revisions to its first ERAS proposal presented to stakeholders including changing the mechanics of how a RERRA would notify MISO that a project is suitable for ERAS, establishing the sunset date, and determining some of the eligibility requirements for ERAS participation. OMS provided significant input on the appropriate method for states or RERRAs to notify MISO of projects suitable for MISO's first ERAS proposal. That engagement and feedback helped MISO produce its original ERAS filing to the Commission in March of this year. Following the Commission's order, MISO developed a proposed method for RERRAs to establish a connection between a proposed ERAS project and a resource adequacy deficiency or a spot load addition to address the Commission's guidance and shared its proposed method with individual states and OMS. MISO directly engaged in discussions to address any concerns and this resulting filing is responsive to these conversations and represents a significant step forward towards improving the interconnection process in MISO and enabling it to meet state and RERRA needs. MISO has developed this refiling on an expedited basis and MISO has shared updates with our states to keep them informed of MISO's direction as it finalized the refinements to the original ERAS proposal. While states recognized that a full review of the filing will be required to indicate their support, MISO believes many are generally supportive of the framework and recognize the urgency of having an expedited review process in place.

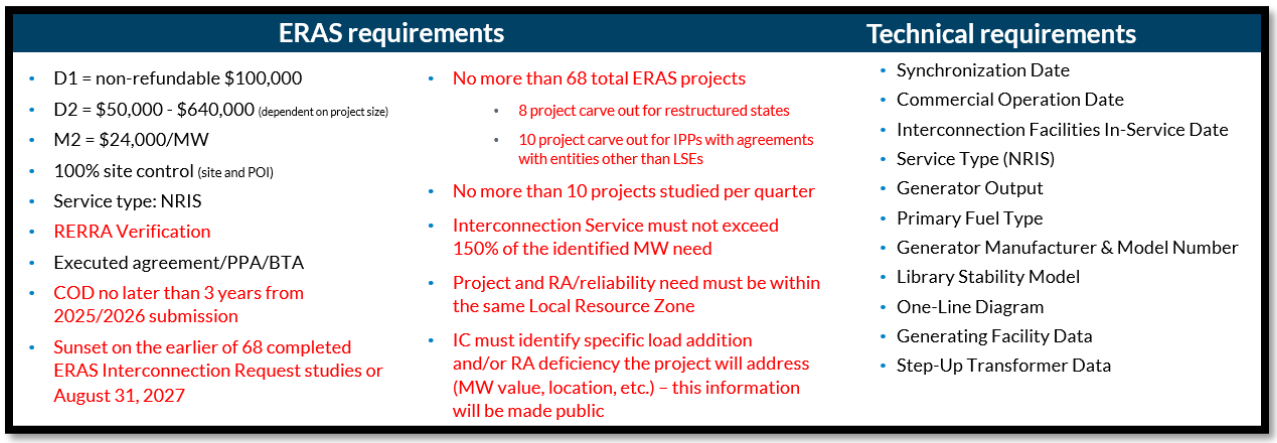
In preparing this filing and refining the ERAS process as described further below, MISO took substantive steps to mitigate the impact of these proposed changes on Interconnection Requests in the queue. MISO remains committed to reducing its general interconnection review period to one year and is utilizing industry-leading techniques, processes, and IT systems to achieve that goal. MISO's recent GIP Improvement and Cap filings were implemented to facilitate this process, but reaping the benefits of those changes will take longer than is necessary to address the looming resource adequacy and reliability needs faced by the states now. ERAS is a unique process that will enable a limited and now capped number of projects to address resource adequacy and reliability needs in the short term. The ERAS process remains structured to insulate projects in the queue from the negative impacts or cost shifts as the result of projects either entering ERAS or leaving the generator interconnection queue for ERAS. As such, the consideration of ERAS projects will not raise costs for or otherwise impact any of the projects currently in the queue.

D. Changes and Refinements to the ERAS Process

The refined Expedited Resource Addition Study ("ERAS") is MISO's answer to addressing the resource adequacy and reliability needs in the near-term. ERAS is a unique process which recognizes that the responsibility for providing grid reliability and resource adequacy in the MISO region is shared by Load Serving Entities ("LSEs"), the states, and MISO. Projects that enter ERAS—a process separate from the standard Generator Interconnection Queue—will be studied

serially in each ERAS quarterly study period and will be granted an EGIA within 90 days to facilitate new generation to come online in the short-term to meet valid new, incremental load additions and identified resource adequacy deficiencies. Since the original ERAS filing, MISO has worked to implement necessary changes to the proposal to better align the process with the timeline that is needed to address the looming resource adequacy and/or reliability needs. First, MISO is now proposing to implement a cap on the number of projects that can participate in ERAS. Second, MISO is requiring a stronger demonstration of a connection between the proposed project and the resource adequacy and/or reliability need that warrants its inclusion in ERAS as demonstrated by a verification from the relevant RERRA. The proposed ERAS project and the resource adequacy and/or reliability need must also be within the same Local Resource Zone. Finally, MISO is also proposing Tariff language to incorporate the retail choice states – Illinois and parts of Michigan – into the ERAS process.[28] MISO's goal with developing and refining ERAS is to quickly, efficiently, and effectively craft a process that can manage these looming needs while also addressing concerns raised in the Commission's order. The figure below highlights in red font what features of the original ERAS filing have been refined and added to this proposal.

Figure 1: Refined ERAS Requirements Comparison



Working together, MISO, the states, and other stakeholders established numerous guardrails around projects that could participate in the original ERAS to ensure that the process is used as intended, that only truly necessary and certain projects can enter ERAS, and to mitigate any impact on projects currently in the general interconnection queue. These guardrails continue to include stringent eligibility requirements such as demonstrating 100% site control for the Interconnection Customer's Interconnection Facilities, establishing a three year due date for Commercial Operation Dates ("COD") based on submission date, requiring a non-refundable deposit of $100,000, a $24,000/MW milestone payment, all of which are due upon application, and agreeing to paying for all necessary Network Upgrades per the executed GIA. MISO is also

[28] *See* Tab A Redlines, Attachment X, Section 3.9.1.1(iii).

proposing several changes to the Interconnection Request application to ensure that the necessary information is supplied by the Interconnection Customer when applying to participate in ERAS.

The refined ERAS framework continues to incorporate the role of states and RERRAs but requires a written verification from the RERRA that the proposed project will address a load addition not already planned for or an identified resource adequacy deficiency within its jurisdictional footprint. The Commission has previously recognized that "MISO's resource adequacy construct is designed specifically to complement state mechanisms."[29] MISO continues to support "the independent authority of state regulators for resource adequacy and facilitates resource adequacy goals with state regulators that have decision-making authority over the amount and types of resources that are necessary to meet shared objectives."[30] The ERAS process still provides a vehicle for the RERRA to verify to MISO that there is a valid, new incremental load addition that is not incorporated in relevant plans or that the proposed Generating Facility will address an identified resource adequacy deficiency. While this verification is not *confirmation* by the state/RERRA of a project's approval,[31] and should not be viewed as such, it does directly connect the proposed ERAS project with a specific load need. This, along with the requirement that the load need and the ERAS project must be located in the same LRZ region, better tailors the ERAS process to the resource adequacy and reliability needs.

This refined ERAS proposal also is in alignment with the open access principles establish by the Commission and consistent with the goals of Order Nos. 2003[32] and 2023.[33] Given the dramatic changes the electric industry is undergoing and the increasing demand for electricity expected in the MISO footprint, there is great urgency to establish a process that enables "shovel ready" projects addressing near term resource adequacy and/or reliability needs to be completed

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29 *Midcontinent Indep. Sys. Operator, Inc.*, 170 FERC ¶ 61,215 at P 118 (2020) (citing MISO, FERC Electric Tariff, Module E-1, § 68A (34.0.0). MISO's Module E-1 mandatory requirements for Market Participants serving Load "recognize and are complementary to the reliability mechanisms of the states" and nothing in Module E-1 "affects existing state jurisdiction over the construction of additional capacity or the authority of the states to set and enforce compliance with standards for adequacy."

30 *Id.*

31 As will be further explained Section III.A.2, *infra*, even if a project participates in the ERAS process, regulatory review and approval of the project by the state/RERRA is still required.

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

33 *See Improvements to Generator Interconnection Procs. & Agreements*, Order No. 2023, 184 FERC ¶ 61,054, *order on reh'g*, 185 FERC ¶ 61,063 (2023), *order on reh'g*, Order No. 2023-A, 186 FERC ¶ 61,199, *errata notice*, 188 FERC ¶ 61,134 (2024).

in a short period of time. As revised to address Commission guidance, ERAS provides that capability and will facilitate the quick completion of projects necessary to address resource adequacy and/or reliability needs in the next few years. The package presented in this filing is just and reasonable and supported by testimony and other evidence, and the Commission should approve it promptly to ensure that MISO can initiate the ERAS process as expeditiously as possible.

II. DEVELOPING THE ERAS PROCESS

A. Overview of MISO'S Generator Interconnection Process

In an effort to constantly improve its generator interconnection process, MISO implemented significant changes to the process over the last two years. First, in 2023, MISO submitted a proposal to make certain improvements to the interconnection process, which involved increasing milestone payments, establishing withdrawal penalty requirements, and implementing certain Site Control rules.[34] Second, in 2024, MISO submitted its Queue Cap Proposal, which established a cap on the total MW value of Interconnection Requests entering a given study cluster.[35] These changes to the queue were made primarily to address the unprecedented challenges MISO faced when evaluating the feasibility and certainty of a large number of projects proposing to connect to the MISO Transmission System. These proposals were necessary to address both the quality and quantity of interconnection requests – thus they were aimed at reducing speculative projects in the queue, making the current queue process more efficient, and reducing the causes of delay.

MISO's first cap proposal, submitted in 2023, included an exemption to the cap for any interconnection requests involving a proposed generation facility that was submitted by a RERRA.[36] The RERRA exemption was proposed in recognition that some proposed Generating Facilities may be required by one or more MISO States or other jurisdictional entities to meet their load serving obligations. As MISO explained in its filing, "[p]roviding this exemption is consistent with the cooperative federalism principles underlying the FPA and placing the primary responsibility over resource adequacy on state regulators."[37] Moreover, the Organization of MISO

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[34] *See Midcontinent Indep. Sys. Operator, Inc.*, Docket No. ER24-340-000, MISO's Transmittal Letter (filed Nov. 3, 2023) ("Queue Reform Filing").

[35] *See Midcontinent Indep. Sys. Operator, Inc.*, Docket No. ER25-507-000, MISO's Transmittal Letter (filed Nov. 21, 2024) ("2024 Cap Filing, Transmittal Letter").

[36] *See Midcontinent Indep. Sys. Operator, Inc.*, Docket No. ER24-341-000, MISO's Transmittal Letter (filed Nov. 3, 2023) ("2023 Cap Filing, Transmittal Letter").

[37] 2023 Cap Filing, Transmittal Letter at 16.

States ("OMS") supported the exemption and proposed a procedure for a RERRA to request that an Interconnection Request associated with a project be exempt from the cap.[38] Ultimately, FERC denied MISO's request to approve the 2023 Queue Cap Proposal with the RERRA exemption.[39]

MISO's second Cap Proposal, submitted in 2024, did not include the RERRA exemption. In the testimony, MISO explained that in lieu of the exemption, it would be proposing the ERAS process to "expedite the approval of new generation needed to address state resource adequacy goals."[40] MISO recognized that the RERRA exemption was attempting to address a distinct queue issue that warranted its own proposal to facilitate the approval process of new generation needed to address resource adequacy.[41] In the 2024 Cap Proposal, MISO committed to working on addressing the needs of RERRAs through a new process that would be developed with stakeholders and that would more comprehensively conduct the process for new generation that was addressing resource adequacy and reliability needs.[42]

MISO's original ERAS proposal, submitted in March of 2025, aimed at addressing short-term resource adequacy and reliability needs.[43] The previously proposed ERAS process required enhanced commitments from the Interconnection Customer including 100% Site Control and full commitment to pay for all the costs of identified Network Upgrades per the executed EGIA even if the project is later withdrawn and the EGIA terminated.[44] MISO also required ERAS projects to have written notification from a RERRA indicating that it should be studied in the ERAS process. MISO originally planned to offer 14 cycles of ERAS studies prior to its sunset in 2028. In May 2025, the Commission issued an order rejecting MISO's proposal and identified two main problems with the initial ERAS filing: 1) there was no limitation on the number of projects that could participate; and 2) the RERRA notification was insufficient to establish a connection between the proposed project and the identified resource adequacy and/or reliability need. The Order also included helpful guidance for MISO to follow when refining its proposal.[45]

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[38] *See Midcontinent Indep. Sys. Operator, Inc.*, Docket No. ER24-341-000, Comments of Organization MISO States ("OMS") in support of Midcontinent Independent System Operator, Inc.'s November 3, 2023 (filed Dec. 4, 2023).

[39] *See Midcontinent Indep. Sys. Operator, Inc.*, 186 FERC ¶ 61,054 (2024), *order on reh'g*, 187 FERC ¶ 61,031.

[40] 2024 Cap Filing, Tab C: Prepared Direct Testimony of Andrew Witmeier at 5:2-3.

[41] *See id.* at 29:10-21.

[42] *Id.* at 30:2-7.

[43] *Midcontinent Independent System Operator, Inc.*, "Revisions to the Open Access Transmission, Energy and Operating Reserve Tariff Expedited Resource Addition Study Filing," Docket No. ER25-1674-000 (March 17, 2025) ("ERAS Transmittal Letter").

[44] ERAS Original Filing, Witmeier Testimony at 41:4 –11.

[45] ERAS Order at P 199.

Following this feedback, MISO has made several refinements to its original ERAS proposal. First, MISO is now capping the number of projects that can participate in ERAS to 68 projects total—with a carve out of 8 projects that may only be submitted by retail states for resource adequacy deficiencies and 10 projects that may only be submitted by independent power producers ("IPPs").[46] In addition, MISO is capping the number of projects that can participate in each ERAS Quarterly Study Period to 10 projects no matter if they are proposed by retail states, IPPs, or other applicants.[47] MISO also changed the RERRA requirement to include a verification instead of a notification to better establish a nexus between the proposed ERAS project and the identified resource adequacy and/reliability need. MISO is now requiring that the ERAS project be within the same LRZ as the load it is addressing unless the project applicant can demonstrate that the use of a Generating Facility not in the same LRZ was included in a resource filing or other submission made to the relevant RERRA.[48] A project applicant for ERAS must now supply three documents: 1) the RERRA verification; 2) the off-taker agreement; and 3) the Interconnection Request for ERAS that contains additional information requirements. MISO believes that this documentation will serve to demonstrate that the proposed ERAS project is targeted at serving a specific resource adequacy deficiency and/or reliability need and will serve to identify the parties involved in the agreement. The refined ERAS process will only be offered until August 31, 2027, or when 68 ERAS Interconnection Request studies have been completed, whichever comes first.[49] And all ERAS projects must be completed and commercially operable three years after their submission date.[50]

ERAS is MISO's short-term solution to the resource adequacy and reliability problems that it is facing in its footprint. The revised proposal filed herein is temporary but critically necessary as a bridge to ensure time-sensitive new resource adequacy needs will be met while MISO works with its stakeholders to reduce the processing time of its queue by 2028. By necessity, the process is flexible enough to be utilized by all RERRAs in MISO's footprint that need such a tool and by any type of Interconnection Customer with a qualifying project. The stringent entry requirements, the newly instituted project cap, the modified RERRA verification, the additional application requirements, and robust process safeguards make ERAS a process that is flexible enough while

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[46] Witmeier Testimony at 4:3-9.

[47] *Id.* at 4:5-6, 17:3-5, 27:8-15.

[48] *Id.* at 4:6-15.

[49] Witmeier Testimony at 49:6-15. This time limitation also applies to the retail state projects. If the retail states do not submit their allotted eight projects by the sunset date, the ERAS process will still close on August 31, 2027.

[50] Witmeier Testimony at 47:14-17. One exception to this rule is if the project has been deferred to a future ERAS quarterly study cycle.

remaining narrowly scoped and appropriately bounded to prevent misuse or negative impacts for projects in the MISO queue.

B. Imminent Resource Adequacy and Reliability Concerns

Like the other RTOs and ISOs, MISO's resource adequacy concerns are driven by unexpected but significant load growth associated with large data center development, the accelerated retirement of baseload generation due to state and federal policies, a resurgence of manufacturing, and delays in the generator interconnection queue caused by speculative projects, late-stage dropouts, supply chain delays, and permitting or financing issues. What is unique to MISO as compared to other RTOs and ISOs is that it is almost completely comprised of vertically integrated utilities who are responsible for serving load within their jurisdictions. The LSEs are accountable for supplying their customers with consistent power and must ensure that they can address resource adequacy needs in a time-sensitive manner. Thus, MISO must partner *with* the states and their RERRAs and LSEs to provide a way for projects that have been identified as necessary for resource adequacy or reliability needs to be completed quickly. MISO's outlook on resource adequacy within its footprint is supported by several studies that are completed on a regular basis. As these studies demonstrate, the load growth outlook has changed dramatically in the past few years due to unforeseen changes in the electricity industry.

First, MISO's Reliability Imperative Report found that the transition towards decarbonization is "posing material, adverse challenges to electric reliability."[51] The Report recognized that major industry trends are "simultaneously changing the conditions of the system" and that demand for electricity is increasing to meet new needs, which is disrupting traditional load patterns.[52] MISO noted that over the last decade, surplus reserve margins in MISO have been exhausted through load growth and unit retirements.[53] "While MISO has implemented several reforms to help avert near-term risk, more work is urgently needed to mitigate reliability concerns in the coming years."[54] MISO also published the MISO Futures Report, which provides the analysis of three scenarios to help MISO envision a set of possible resource adequacy outcomes up to 20 years in the future. The scenarios establish a range of economic, policy, and technological possibilities including load growth, electrification, decarbonization, renewable energy levels,

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[51] *See MISO's Response to the Reliability Imperative,* Executive Summary (updated February 2024) at 1, https://cdn.misoenergy.org/Executive%20Summary%202024%20Reliability%20Imperative%20report%20Feb.%2021%20Final631825.pdf.

[52] *Attributes Roadmap, A Reliability Imperative Report* (December 2023) at 6, https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf.

[53] *See MISO's Response to the Reliability Imperative,* (updated February 2024) at 6, ("Reliability Imperative"), https://cdn.misoenergy.org/2024%20Reliability%20Imperative%20report%20Feb.%2021%20Final504018.pdf?v=20240221104216.

[54] *Id.*

generator retirements, fuel prices, and generation capital costs. While MISO originally published the Series 1 analysis in 2022, due to the dramatic changes in the energy industry even in the last couple of years, MISO was required to update the outlook as its "members' and states' plans were refined, new legislation and policies took effect, and prices, along with incentives for various resources, saw significant changes."[55] As a result of these changes, MISO was required to revise the Series 1 Futures earlier than anticipated with updated data "to reflect a significant fleet transition over the next 20 years."[56] Both Futures Reports demonstrated the immediate need to add almost twice the generation that MISO currently has online, and that rate is increasing as a result of the unprecedented load growth.[57]

Second, the annual OMS-MISO Survey indicated similar results in 2024, "reinforc[ing] near-term risks and highlight[ing] key uncertainties impacting resource adequacy in the MISO region."[58] The survey compiles information about new resources that the utilities and states plan to build and about any older assets they intend to retire in the coming years. The 2024 survey finds that "resource adequacy risks could grow over time across all seasons, absent increased new capacity additions and actions to delay capacity retirements."[59] The survey noted that "significant economic development activities are spurring new, large spot-load additions (e.g., data centers, onshoring of manufacturing, new industrials) and increasing pressures on resource adequacy and requiring improved abilities for the timely addition of new resources."[60] EPRI, Grid Strategies, and MISO also anticipate strong long-term load growth that is driven by data centers, manufacturing, increased cooling demands, electric vehicles, and cryptocurrency.[61] Grid Strategies even noted "[o]ver the past year, grid planners nearly doubled the 5-year load growth

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55 *MISO Futures Report Series 1A* (Nov. 1, 2023) at 2, https://cdn.misoenergy.org/Series1A_Futures_Report630735.pdf.

56 *Id.*

57 *Id.* at 6-8; *see also*, *MISO Futures Report* (updated December 2021) at 4, https://cdn.misoenergy.org/MISO%20Futures%20Report538224.pdf.

58 *See 2024 OMS-MISO Survey Results* (June 20, 2024), ("2024 OMS-MISO Survey") at 2, https://cdn.misoenergy.org/OMS%20MISO%20Survey%20Results%20Workshop%20Presentation628355.pdf.

59 *Id.*

60 *Id.*

61 *2024 OMS-MISO Survey* at 12*; see also* EPRI, *Reindustrialization, Decarbonization, and Prospects for Demand Growth* (Jul. 27, 2023), https://www.epri.com/research/products/000000003002027930; John D. Wilson and Zach Zimmerman, Grid Strategies, *The Era of Flat Power Demand is Over* (December 2023), ("Grid Strategies Report"), https://gridstrategiesllc.com/wp-content/uploads/2023/12/National-Load-Growth-Report-2023.pdf.

forecast."[62] The 2024 OMS-MISO survey also noted that "immediate actions are needed to expedite the addition of new capacity, coordinate resources for new load additions, and potentially moderate the pace of resource retirements."[63]

The recently published 2025 OMS-MISO Survey further "reinforces near-term risks and highlights key uncertainties impacting resource adequacy."[64] The 2025 survey shows a range of outcomes but indicates that "[a]t least 3.1 GW of new resources are needed by summer 2026/27 to avoid a resource deficit, with greater needs in future years."[65] The survey responses "show increasing load forecasts year-over-year and are close to the high end of MISO Long-Term Load Forecast."[66] The 2025 survey noted that data centers, electric vehicles, and industry development are anticipated to have a high impact in MISO's footprint.[67] Finally, the 2025 Survey recognized that there is significant uncertainty in projected resource adequacy, underscoring the urgent need for accelerated resource additions, strategic retirement planning and proactive management of increasing load growth. Using both the Regional Resource Assessment ("RRA") and OMS-MISO Survey together provides a unique outlook for resource planners as the RRA is "a 20-year outlook based on publicly announced resource plans and policy goals" while the OMS-MISO Survey is "more focused on the near term and projects new installed capacity coming online at the pace at which resources have received interconnection agreements and come online in recent history."[68]

Third, the 2024 NERC Long-Term Reliability Assessment highlighted the mounting reliability challenges faced by the energy industry caused by accelerating generator retirements, declining dispatchable resources, and escalating demand growth.[69] NERC noted that "[e]lectricity peak demand and energy growth forecasts over the 10-year assessment period continue to climb;

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62 *Grid Strategies Report* at 3.

63 *2024 OMS-MISO Survey* at 16.

64 *See 2025 OMS-MISO Survey Results* at 2.

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

66 *Id.* at 10.

67 *Id.* at 10.

68 Comments of Todd Ramey on behalf of MISO at 9, Docket No. AD25-7, May 28, 2025 ("MISO RA Tech Conference Comments").

69 *See NERC 2024 Long-Term Reliability Assessment* (December 2024), ("NERC Report") https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf.

demand growth is now higher than at any point in the past two decades."[70] The assessment found that for 2025-2029, MISO was categorized as high risk for falling below established resource adequacy criteria.[71] The Report determined that resource additions were not keeping up with generator retirements and demand growth in the MISO footprint.[72] "MISO is at a high risk of experiencing electricity supply shortfalls beginning in Summer 2025 based on [prospective reserve margins] derived from anticipated resources and demand forecasts."[73] As part of NERC's assessment of MISO, it explained that "[i]ncreased coordination between MISO and its members will be critical to ensuring reliability throughout this resource transition of integrating new intermittent resources and continuing to retire conventional resources."[74]

More recently, NERC issued its summer reliability assessment for 2025.[75] In its report, NERC noted that "[s]ince last summer, the aggregate of peak electricity demand for NERC's 23 assessment areas has risen by over 10 GW – more than double the year-to-year increase that occurred between the summers of 2023 and 2024."[76] NERC also identified MISO has having resource adequacy or energy risks for the summer and noted elevated "potential for insufficient operating reserves in above-normal conditions."[77] NERC similarly highlighted 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."[78] Finally, in its assessment, NERC noted that "[t]he summer of 2024 was the fourth hottest on record for both the contiguous United States and Canada, with some areas experience their hottest summer ever. The result was record electricity demand in the United States as well as in Canada."[79]

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[70] *Id.* at 8.

[71] *Id.* at 6.

[72] *Id.* at 7.

[73] *Id.* at 13.

[74] *Id.* at 43.

[75] *2025 Summer Reliability Assessment*, North American Electric Reliability Corporation, May 2025, ("NERC 2025 Assessment"), https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf.

[76] *Id.* at 5.

[77] *Id.* at 10.

[78] *Id.* at 16.

[79] *Id.* at 50.

Finally, MISO submitted comments prior to FERC's Technical Conference on the challenge of resource adequacy in RTO and ISO regions, which was held on June 4 and 5, 2025.[80] In its comments, MISO noted that "the MISO region faces resource adequacy and reliability challenges due to the changing characteristics of the electric generating fleet, insufficient transmission system infrastructure, growing pressures from extreme weather, and rapid load growth."[81] MISO explained that it is expecting significant growth in wind and solar development: "MISO's Future Planning Scenarios estimate that while the total amount of installed electric generation will increase significantly over the next 20 years due to the rapid growth of wind and solar, the actual amount of electricity available to the system during could face a net decline of about 32 GW due to the operational characteristics of these new resources."[82] MISO also emphasized that "based on the current trajectory, peak electric load in the MISO region is projected to grow at a 1.6% compound annual growth rate ('CAGR'). This compares to an average 0.5% CAGR between 2009 and 2024 and threatens to outpace new electric resource additions if urgent action isn't taken."[83] MISO concluded that "[w]ith the pace of change confronting the electricity system, the impending influx of large data centers and the evolving generation portfolio there is heightened urgency to ensure the system remains reliable."[84] NERC also submitted comments in this docket noting that "growth projections of electric demand have reached heights unseen in decades, disrupting resource adequacy plans across North America."[85]

Collectively, these reports and comments provide a perspective demonstrating that MISO and its members need to act quickly and collaboratively to address resource adequacy and reliability needs in the MISO footprint over the next five years.[86] The original ERAS proposal was developed by MISO in coordination with its stakeholders to address these needs and to enable projects addressing resource adequacy and/or reliability to be brought online quickly. As NERC recognized, "MISO's resource adequacy construct complements the jurisdiction that regulatory authorities have in determining the necessary level of adequacy."[87] The refined ERAS proposal

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80 MISO RA Tech Conference Comments at 1.

81 *Id.*

82 *Id.* at 2.

83 *Id.* at 3.

84 *Id.* at 27.

85 Prefiled Statement of Jim Robb, President and CEO of North American Electric Reliability Corporation at 1, Docket No. AD25-7, May 19, 2025 ("NERC RA Tech Conference Comments").

86 In fact, MISO updated the Futures Report from November 2023 used to study LRTP Tranche 2.1 because load assumptions changed so dramatically over the past year and half.

87 NERC Report at 43.

further enables MISO to work *with* its members to address resource adequacy and reliability needs in the short-term.

C. Development of ERAS and the Stakeholder Process

Between November of 2024 and March of 2025, MISO conducted an extensive stakeholder process, which included discussions, presentations, and numerous opportunities for stakeholder input at the Planning Advisory Committee ("PAC") and also in ERAS-specific workshops. The stakeholder engagement process for MISO's ERAS proposal went as follows:

- November 13, 2024: MISO introduced the need for ERAS at the PAC and requested formal written feedback from stakeholders.[88]

- November 18, 2024: MISO and stakeholders participated in a special ERAS-specific workshop in which the parties continued to discuss ERAS details. MISO sought feedback on the ERAS proposal.[89]

- December 6, 2024: MISO and stakeholders participated in a second ERAS-specific workshop in which the parties continued to discuss ERAS details. MISO sought feedback on the updated proposal.[90]

- January 22, 2025: MISO presented an updated ERAS proposal at the PAC.[91]

- February 19, 2025: MISO posted proposed tariff redlines, presented an updated ERAS proposal, and sought feedback at the PAC.[92]

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[88] *See Expedited Resource Adequacy Study (ERAS) Introduction* (November 13, 2024), https://cdn.misoenergy.org/20241113%20PAC%20Item%2009%20Expedited%20Resource%20Adequacy%20Study%20(ERAS)%20Introduction660245.pdf.

[89] *See Expedited Resource Adequacy Study (ERAS) Workshop* (November 18, 2024), https://cdn.misoenergy.org/20241118%20Expedited%20Resource%20Adequacy%20Study%20(ERAS)%20Workshop661622.pdf.

[90] *See Expedited Resource Adequacy Study (ERAS) Workshop* (December 6, 2024), https://cdn.misoenergy.org/20241206%20Expedited%20Resource%20Adequacy%20Study%20(ERAS)%20Workshop665747.pdf.

[91] *See Expedited Resource Addition Study (ERAS) Proposal* (January 22, 2025), https://cdn.misoenergy.org/20250122%20PAC%20Item%2006c%20Expedited%20Resource%20Addition%20Study%20(ERAS)%20Proposal%20(PAC-2023-1).pdf673403.pdf.

[92] *See Expedited Resource Addition Study (ERAS) Proposal* (February 19, 2025), https://cdn.misoenergy.org/20250219%20PAC%20Item%2009%20Expedited%20Resource%20Addition%20Study%20(ERAS)%20Proposal%20(PAC-2023-1)679608.pdf.

- March 7, 2025: MISO posted updated proposed tariff redlines and presented the final ERAS proposal at a special PAC meeting scheduled to review the ERAS proposal.[93]

- November 2024 – March 2025: MISO staff engaged in dozens of individual calls with stakeholders to discuss what changes they think should be made to the ERAS proposal.

In addition to these more general stakeholder meetings, OMS provided significant input on the appropriate method for states or RERRAs to notify MISO of projects suitable for ERAS. Collaboration between MISO and OMS on the mechanics of the RERRA notification process and the language added to MISO's Tariff was key. The input from OMS ensures that the ERAS process can be utilized across the footprint even though the regulatory processes differ in each state.

Following the Commission's rejection of MISO's original ERAS filing and the guidance provided in its Order, MISO re-engaged with its stakeholders to develop the refined ERAS proposal as developed in herein. MISO presented its refined ERAS proposal at the May 28, 2025 PAC meeting where MISO presented the disposition of its original ERAS filing in Docket No. ER24-1674.[94] MISO received feedback from stakeholders following the PAC meeting through its informal feedback tool.[95]

D. States Have Authority Over Resource Adequacy

Due to MISO's unique organizational structure consisting of almost exclusively vertically integrated utilities, resource adequacy determinations must be made in collaboration with the states. As MISO recently explained in comments filed with FERC, "[e]very effort in pursuit of the Reliability Imperative is centered around the shared responsibility between MISO-member electricity providers, states, and MISO to maintain a reliable grid."[96] FERC has recognized that state authority over resource adequacy is emphasized more in MISO than in other RTOs.[97] MISO

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93 *See Expedited Resource Addition Study (ERAS) Proposal* (March 7, 2025), https://cdn.misoenergy.org/20250307%20PAC%20Item%2002%20Expedited%20Resource%20Addition%20Study%20(ERAS)%20Proposal%20(PAC-2023-1)684427.pdf.

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

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

96 MISO FERC RA Tech Conference Comments at 27.

97 ERAS Order at P 203 ("We recognize that, given their authority, responsibilities, and expert assessment of their resource adequacy needs, it is appropriate for RERRAs to communicate to MISO their resource adequacy and

firmly believes that it should not be selecting ERAS projects that may address resource adequacy or reliability needs, but rather that responsibility is firmly within the states' jurisdiction. In fact, "[s]ince MISO's inception, deference has been made to the jurisdictional authority of the states and other RERRAs with respect to resource adequacy rights and responsibilities that RERRAs take seriously."[98]

The overlap between state and federal authority in the electric industry is governed by the Federal Power Act ("FPA").[99] "The Commission is a creature of statute and has jurisdiction only over those matters that Congress has given it the authority to regulate."[100] To that end, FERC has jurisdiction over regulating interstate "wholesale" electricity sales and transmission markets, whereas the states have jurisdiction over "retail" sales and "over facilities used for the generation of electric energy."[101] Under the FPA, federal and state powers are "complementary" and "like all collaborative federalism statutes, envisions a federal-state relationship marked by interdependence."[102] Thus, determining "resource adequacy raises 'complex jurisdictional concerns' which at times are at the 'confluence of state-federal jurisdiction.'"[103] At this confluence, FERC has recognized that "this bifurcated framework respects the jurisdictional boundaries of the FPA while recognizing the states' historical role in ensuring resource adequacy."[104] FERC has clearly stated that "a workable approach to resource adequacy does not mean that we should ignore the states' traditional role in this area."[105] Thus, "[w]ith the exception of the broad authority of [FERC], over the need for and pricing of electrical power transmitted in interstate commerce … these economic aspects of electrical generation have been regulated for

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reliability needs, as well as their support for including interconnection requests in the ERAS process, to ensure that the RERRA's needs are met in a timely fashion.").

98 MISO FERC RA Tech Conference Comments at 12.

99 16 U.S.C. § 824 (1976).

100 *PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,115 at P 66 (2025) ("Co-Location Order") (citing *Atl. City Elec. Co. v. FERC*, 295 F.3d 1, 8 (D.C. Cir. 2002)).

101 16 U.S.C. § 824(b)(1).

102 *Hughes v. Talen Energy Mktg., LLC*, 578 U.S. 150, 167 (2016) (Sotomayor, J., concurring); *see also FERC v. Electric Power Supply Ass'n*, 577 U.S. 260, 289 (2016) ("EPSA").

103 *Plan. Res. Adequacy Assessment Reliability Standard*, 134 FERC ¶ 61,212 at P 20 (2011) (citing *Cal. Indep. Sys. Operator Corp*., 116 FERC ¶ 61,274 at P 1112 (2006), *order on reh'g*, 119 FERC ¶ 61,076 (2007), *order on reh'g* 120 FERC ¶ 61,271 (2007)).

104 *See California Indep. Sys. Operator Corp.*, 116 FERC ¶ 61,274 at P 1117 (2006); *Cxa La Paloma, LLC*, 165 FERC ¶ 61,148 at P 70 (2018).

105 *California Indep. Sys. Operator Corp.*, 116 FERC ¶ 61,274 at P 1117 (2006).

many years and in great detail by the states."[106] Notably, the states have long relied on the FPA's reservation of state control over their own generation as an unambiguous sanction of states' authority to control their own resource mix.[107] Similarly, FERC has recognized this sanction of authority to the states to control their own resource mix.[108]

The Supreme Court has similarly recognized this jurisdictional overlap and the states' authority in this area. "Alongside those grants of power [under the FPA], however, the Act also limits FERC's regulatory reach, and thereby maintains a zone of exclusive state jurisdiction."[109] "But the law places beyond FERC's power, and leaves to the States alone, the regulation of 'any other sale' – most notably, any retail sale – of electricity."[110] This reserved authority to the states includes control over in-state "facilities used for the generation of electric energy."[111] The Supreme Court explained that the "need for new power facilities" is "characteristically governed by the states."[112] "These matters are consistent with those that the Supreme Court has long held to be within the states' historic police powers, and the Court has observed that the FPA's jurisdictional divide 'was drawn with meticulous regard for the continued exercise of state power, not to handicap or dilute it in any way.'"[113] Finally, the Supreme Court has similarly determined that, under the FPA, the states have authority over their generation resource mix.[114]

This unique jurisdictional overlap affects how MISO collaborates with the 15 states in its footprint in determining resource adequacy needs. Compared to other RTOs and ISOs, resource adequacy is viewed and treated differently in MISO, which runs a voluntary capacity market and

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106 *Pac. Gas & Elec. Co. v. State Energy Res. Conservation & Dev. Comm'n*, 461 U.S. 190, 205–06 (1983).

107 *See Hughes*, 578 U.S. at 166; *EPSA*, 577 U.S. at 266 (explaining that the FPA "limits FERC's regulatory reach, and thereby maintains a zone of exclusive state jurisdiction.").

108 *See California Indep. Sys. Operator Corp.*, 116 FERC ¶ 61,274 at P 1118 (2006) ("While we find that resource adequacy is necessary for the reliable operation of the grid, and to ensure that wholesale rates are just, reasonable and not unduly discriminatory, we are not establishing planning reserve requirements, but instead are adopting those set by state and Local Regulatory Authorities in the first instance.").

109 *EPSA*, 577 U.S. at 266.

110 *Id.* at 265 (citing § 824(b)).

111 *Hughes*, 578 U.S. at 154 (quoting § 824(b)(1)).

112 *Id.* (quoting *Pac. Gas & Elec. Co. v. State Energy Res. Conservation & Dev. Comm'n*, 461 U.S. at 205).

113 Co-Location Order, 190 FERC ¶ 61,115 at P 67 (2025) (citing *Munn v. People of State of Ill.*, 94 U.S. 113 (1876) and quoting *Oneok, Inc. v. Learjet, Inc.*, 575 U.S. 373, 384-85 (2015) (discussing the analogous provisions in the Natural Gas Act) (internal citations omitted)).

114 *See, e.g., Citizens Action Coal. of Ind., Inc. v. FERC*, 125 F.4th 229, 238 (D.C. Cir. 2025) (citing 16 U.S.C. § 824(b)(1)).

the states in the MISO footprint direct their utilities to meet resource adequacy requirements.[115] Notably, FERC "has consistently rejected a one-size-fits all approach to resource adequacy in the various RTOs/ISOs due, in large part, to significant differences between each region and also due to the well-established tenet that there can be more than one just and reasonable rate."[116] FERC has recognized that these differences set MISO apart from other RTOs/ISOs in meaningful ways. First, "[t]he vast majority (approximately 90 percent) of MISO's load is served by vertically integrated utilities over which state and local authorities play an active role in ensuring resource adequacy. In fact, even states with retail competition (i.e., Illinois and Michigan) have played an active role in ensuring resource adequacy."[117] Second, FERC has also recognized that "MISO's resource adequacy construct is designed specifically to complement state mechanisms" and "supports the independent authority of state regulators for resource adequacy and facilitates resource adequacy goals with state regulators that have decision-making authority over the amount and types of resources that are necessary to meet shared objectives."[118] Applying Section 201(b) of the FPA, the D.C. Circuit has similarly explained that states have the authority "to take any other action in their role as regulators of generation facilities without direct interference from the Commission."[119]

As the reliability operator, MISO is responsible for ensuring reliability for the 15 states that make up its footprint. As a result of this unique resource adequacy and reliability construct, collaborating closely with the states/RERRAs was a necessary part of creating the original ERAS process. Courts have recognized that FERC may not prevent a state "from using the resources [the state] has chosen to promote" and that "[t]he states may use any resource they wish to secure the capacity they need."[120] It is incumbent upon the Interconnection Customer to identify the specific need(s) its project will address and upon the states or RERRAs to notify MISO that these projects in fact merit expedited study so that they can be available promptly if approved through the

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[115] *See* MISO, *Planning Resource Auction*, MISO, ("MISO's resource adequacy construct complements the jurisdiction that regulatory authorities have in determining the necessary level of adequacy. It also works in concert utilities that provide demand forecasts that help drive the development of local and regional requirements.") https://www.misoenergy.org/planning/resource-adequacy2/resource-adequacy/#t=10&p=0&s=FileName&sd=desc. MISO runs a centralized capacity auction, known as the planning resource auction, but also allows LSEs to meet the resource adequacy requirement by submitting a fixed resource adequacy plan or through bilateral contracting. MISO, *Planning Resource Auction: Results for Planning Year 2024-25* (Apr. 25, 2024), 2024 PRA Results Posting 20240425632665.pdf.

[116] *Cxa La Paloma, LLC*, 165 FERC ¶ 61,148 at P 76 (2018).

[117] *Midcontinent Indep. Sys. Operator, Inc.*, 162 FERC ¶ 61,176 at P 67 (2018).

[118] *Midcontinent Indep. Sys. Operator, Inc.*, 170 FERC ¶ 61,215 at P 118 (2020).

[119] *Connecticut Dep't of Pub. Util. Control v. FERC*, 569 F.3d 477, 481 (D.C. Cir. 2009).

[120] *New Jersey Board of Public Utilities v. FERC*, 744 F.3d 74, 96-97 (3d Cir. 2014) (quoting *Connecticut Dep't of Pub. Util. Control*, 569 F.3d at 481-82.

applicable RERRA's regulations and processes. The states have many different processes for identifying these needs—some utilize top-down integrated resource planning, some utilize subsidies to encourage certain resource classes, and others directly procure new generation mix toward resources. MISO simply facilitates the ERAS process, which enables projects addressing resource adequacy and/or reliability needs to be reviewed in an expedited manner.

MISO appreciates the Commission's recognition of the RERRAs' "authority, responsibilities, and expert assessment of their resource adequacy needs" and has worked to reflect their responsibility in its refined ERAS proposal.[121] In its refined proposal, MISO has worked to describe how the ERAS process is sufficiently targeted to study *only* interconnection requests that are needed to meet the anticipated shortfall in generating capacity. MISO cannot establish a process on its own—it must implement a process that all 15 of its member-states can participate in. To that end, MISO is looking to the RERRAs to verify that the new, incremental load addition claimed by the Interconnection Customer is valid and not otherwise included in a resource plan or other process under the RERRA's purview or a resource adequacy deficiency that the ERAS projects are being proposed to address. Certain elements are required and MISO needs several parties to be actively involved in ERAS for it to work both legally and practically: a time-critical resource adequacy and/or reliability need must exist, a project applicant must propose an ERAS project to address that need, the RERRA must verify that the new, incremental load is valid or the resource adequacy deficiency exists. Finally, MISO needs to provide the process to enable the load need to be timely addressed. MISO's refined proposal fully incorporates each of these requirements and in way that encourages participation across its footprint.

III. THE PROPOSED REVISIONS ARE JUST AND REASONABLE

FERC applies an independent entity variation standard to evaluate proposals by RTOs and ISOs for revisions to the procedures outlined in Order No. 2003 and Order No. 2023.[122] Consistent with Order Nos. 2003 and 2023, MISO may seek variations from the *pro forma* Large Generator Interconnection Procedures ("LGIP") and Large Generator Interconnection Agreement ("LGIA") if those variations "are just, reasonable, not unduly discriminatory or preferential, and accomplish the purpose of " the terms proposed in Order Nos. 2003 and Order 2023.[123]

MISO's refined ERAS proposal meets this standard. The instant filing addresses a significant and concrete need that was identified and confirmed in the MISO stakeholder process for the original ERAS filing, numerous load forecasts, and by MISO in its administration as the reliability operator for the midcontinent. The supporting evidence demonstrates that the current

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121 ERAS Order at P 203.

122 Order No. 2003, FERC Stats. & Regs. ¶ 31,146 at PP 822-827; Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160 at P 759.

123 Order No. 2003, 104 FERC ¶ 61,103 at PP 825-826; Order No. 2023, 184 FERC ¶ 61,054 at P 1764.

queue mechanisms will not be able to effectively address the resource adequacy and/or reliability needs that the states have in the short-term. MISO is proposing to study a capped number of ERAS projects on a serial basis to accelerate the review time so that urgently needed and "shovel ready" projects are able to reach a GIA faster. Utilizing serial studies for ERAS accomplishes the purpose of Order Nos. 2003 and 2023 by minimizing the restudy risk that is inherent to multi-phase cluster studies so ERAS projects can be built quickly, without the risk of cascading restudies. Although the use of cluster studies is appropriate for the large queue volume seen in MISO's Definitive Planning Phase ("DPP") process, the use of serial studies for ERAS will allow MISO to quickly study ERAS projects to address resource adequacy and/or reliability concerns and to meet the goals of the temporary ERAS process. MISO requests that the Commission find all Tariff revisions proposed in this filing just and reasonable and consistent with the goals of Order No. 2003 and Order No. 2023 because "they foster[] increased development of economic generation by reducing interconnection costs and time[.]"[124]

The Tariff revisions proposed in this filing are limited in scope and in impact on the generator interconnection queue but offer significant benefits in terms of addressing resource adequacy and reliability concerns in MISO, and therefore the Commission should accept them as just and reasonable.[125] Redlined and clean versions of the revised Tariff sheets are included as Tabs A and B, respectively.[126] This filing is also supported by the Direct Testimony of Andrew Witmeier, MISO's Director of Resource Utilization, included as Tab C with this filing.

A. Refinements Made to the ERAS Process

Following the Commission's order on its original ERAS filing, which provided helpful guidance for how MISO could move forward with ERAS, MISO worked to quickly implement changes to the proposed ERAS process to address the Commission's concerns while also crafting a process that can be started this year. To that end, MISO is proposing several changes to its original ERAS proposal, which it believes will address the Commission's concerns and other feedback received from stakeholders. The following figure demonstrates how MISO's ERAS proposal has evolved since its inception.

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[124] *Id.* at PP 11-12.

[125] *See* Tab A Redlines. In the event of a discrepancy between the redlines as described in this letter and those included in the attached Tariff sheets, MISO intends for the language in the attached Tariff sheets to govern.

[126] MISO notes that its compliance filing for FERC Orders 2023 and 2023-A, 184 FERC ¶ 61,054 (2023) 186 FERC ¶ 61,199 (2024)) ("Order No. 2023-A"), remain pending before the Commission in Docket No. ER24-2046-000. Thus, some of the proposed Tariff sections will require renumbering once MISO has received orders on this filing and its Order 2023 compliance. MISO intends to make a "true up" filing to address reconcile these versions of its Tariff promptly after receiving Commission orders accepting the applicable Tariff sections.

Figure 2: ERAS Proposal Changes from Inception

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

This chart demonstrates how MISO has worked with stakeholders to address concerns related to ERAS implementation and how its revised proposal responds to these concerns and Commission guidance. MISO is committed to proposing a process that can and will be used by its member states, which has required numerous iterations of the ERAS proposal.

1. Implementation of an ERAS Project and Quarterly Study Period Project Cap

In the Commission's order rejecting MISO's original ERAS filing, it emphasized that "MISO's proposed Tariff places no limit on the number of projects that could be entered into the ERAS process" and was concerned that "an ERAS queue with processing times for interconnection requests that are too lengthy to meet MISO's stated resource adequacy and reliability needs similar to the challenges with the current DPP queue."[127] In response to this feedback, MISO is now implementing a cap on the number of projects that may participate in ERAS: 68 projects total that will be studied in ERAS until the sunset date of August 31, 2027.[128] Additionally, MISO has carved out a maximum of 8 projects (of the total 68 ERAS projects) that may be submitted to serve

[127] ERAS Order at P 199.

[128] Witmeier Testimony at 26:11-19, 27:1-7, 49:6-15.

retail choice load and a maximum of 10 projects (of the total 68 ERAS projects) that may be submitted by IPPs with agreements with entities other than LSEs.[129] Thus, of the total 68 ERAS projects – 8 projects may be submitted to serve retail choice load, 10 projects may be submitted by IPPs, and 50 projects may be submitted by the remaining project applicants for non-retail choice states.

In addition to the total ERAS project cap and the carve outs, MISO is also implementing a cap of 10 projects that will be accepted and studied per ERAS quarterly cycle. Implementing a project cap per ERAS quarterly study period will enable MISO to adequately study each of the proposed projects in the accelerated timeframe that is required by ERAS.[130] The 10 projects per quarterly study cycle will be selected based on time of submission, but MISO also plans to implement a wait list for any projects that apply beyond the 10th project. Then MISO will implement a screening process to ensure that each of 10 proposed ERAS projects are not within the same geographic area or do not impact the same constraint. If any of the 10 projects are found to be within the same area or impacting the same constraint as another project in that same ERAS quarterly study period, then the project that was submitted later in time will be deferred to the next available quarterly cycle.[131] Then MISO will review any projects in the future quarterly cycles' waitlist to determine whether one of them can be moved up into the previous project's slot, which will require MISO to confirm that the next project is also not in the same geographic zone or addressing the same constraint as one of the nine other proposed projects that were already selected. The remaining projects submitted in that specific cycle that are not accepted for processing will be deferred to future ERAS cycles in order of submission time.

Capping the number of projects per cycle provides numerous benefits for MISO and generators. First, MISO anticipated that a small number of projects would participate per ERAS quarterly cycle, but the cap will ensure that no more than ten are able to be studied per cycle. This will enable MISO to complete the ERAS process more efficiently per project per cycle, which will facilitate the project obtaining an EGIA faster.[132] Second, the cap allows MISO to better plan for the number of projects that will be studied per cycle, which will help MISO efficiently coordinate internal resource needs to complete the studies on time. Knowing the number of projects will also help MISO plan the quarterly study periods out in a more even manner, which will also assist with providing MISO with the necessary information to make additional employee hires if necessary.[133] Third, capping the total number of projects that can participate in ERAS will further minimize the

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[129] *Id.* at 4:3-5, 26:17-19, 27:1-3.

[130] *Id.* at 4:5-6, 17:3-5, 27:8-15.

[131] *Id.* at 27:19-21, 28:1-3, 28:17-23.

[132] *Id.* at 27:8-15.

[133] *Id.* at 17:1-8.

impact on the DPP queue. While MISO stands by its original assertions that the ERAS process will have no impact on projects in the DPP queue and that the strict entry requirements will effectively limit submissions, expressly capping the number of projects that can participate in ERAS will further ensure that there are no negative impacts to projects currently in the queue.[134] Finally, the Commission found PJM's RRI cap to be "reasonably balanced the need to address PJM's resource adequacy challenges with the need to avoid an influx of projects that could overwhelm PJM's interconnection process and lead to further delays, exacerbating the current inability of projects to come online in the near."[135] MISO has the same goal, but plans to spread the number of projects submitted over a slightly longer time period to allow parties time to fully prepare their projects to participate in ERAS.

2. Updating the RERRA Notification Requirement

To reflect the unique jurisdictional authority the states have over generation facilities and resource adequacy needs within their borders, MISO worked closely with OMS to craft the original language that would have allowed a state or RERRA to notify MISO that a proposed project should be considered for the ERAS process in order to meet a claimed resource adequacy and/or reliability need in its jurisdiction. Following the Commission's order, MISO recognized that it needed to change the RERRA requirement and has proposed updated language, which is provided below, in the tariff. In the ERAS application itself, the Interconnection Customer will identify the specific need that its project will address.[136] The Commission noted in its order that "MISO has not demonstrated that the proposed Tariff language is tailored to ensure that only those resources capable of addressing identified near-term resource adequacy or reliability needs are eligible for expedited study through the ERAS process."[137]

Over the past several weeks, MISO has made necessary adjustments to the RERRA language in the ERAS proposal based on FERC's guidance and stakeholder input. To better tailor the RERRA notification to resource adequacy needs, MISO updated the language of the requirement to the following:

> A request for processing through the Expedited Resource Addition Study made by an Interconnection Customer must meet the requirements listed in Section 3.3.1 above, plus the following requirements:

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134 Witmeier Testimony at 53:9-21, 54:1.

135 ERAS Order at P 200.

136 *See* Tab A Redlines, Attachment X, Section 3.3.1.

137 ERAS Order at P 202.

1. The Interconnection Request shall be accompanied by a written verification from the RERRA (or its documented representative) where the load to be served by the Generating Facility is located, subject to the procedures or methods the RERRA requires, that either:

i. the new, incremental load addition claimed by the Interconnection Customer is valid and not otherwise included in a resource plan or other process under the RERRA's purview.

a. The RERRA (or its documented representative) may provide such written verification in conjunction with another state or municipal agency or official (e.g. economic development authority or governor's office) to verify the new, incremental load addition above.

or

ii. the Generating Facility proposed by the Interconnection Customer will address a resource adequacy deficiency as determined by the RERRA, State, Load Serving Entity, or Interconnection Customer. The determination can be supported by:

a. A state energy forecast, or other forward-looking forecast;
b. Commencement of a state proceeding;
c. Review of a RERRA, LSE, or other state resource plan or document, which may include, but is not limited to: integrated resource plans, procurement plans, or other plan or study types;
d. Response to a Request for Proposals (RFP); or
e. Other process, or delegation of authority, as determined by the RERRA or RERRA regulations (including in retail choice states).

or

iii. If an Interconnection Customer's new Generating Facility will address a resource adequacy deficiency and will either:

(1) serve retail choice load located in a state that limits the amount of load that can select retail choice to a percentage of the electric utility's average weather-adjusted retail sales; or

(2) serve load in a retail choice state and will be located in a retail choice state other than one that limits the amount of load that can select retail choice to a percentage of the electric utility's average weather adjusted retail sales,

then the Interconnection Customer will indicate the specific load on the Interconnection Request in Section 4.s of Appendix 1 and provide the evidence of determination in (ii) above, but will not be required to include a written verification, from a RERRA as described in Section 3.9.1(a) or (b). The Transmission Provider shall notify the respective RERRA that an Interconnection Request for a new Generating Facility has been submitted requesting processing through the Expedited Resource Addition Study process and transmit a copy of the Interconnection Request to the respective RERRA. The RERRA shall have 10 Business Days from the date of the Transmission Provider's notification and the simultaneous transmittal of the copy of the Interconnection Request to notify the Transmission Provider that the Interconnection Request should not be considered in the ERAS process. If no such notice is received at the end of 10 Business Days or if the RERRA notifies the Transmission Provider of its non-opposition prior to the end of the 10 Business Days, the Interconnection Request shall be studied through the Expedited Resource Addition Study process provided it meets the requirements listed in Section 3.3.1 and Section 3.9.2.

A RERRA's written verification is not intended to constitute or provide evidence of any final determination of need or suitability of the project for any purpose by the issuing entity beyond requesting that the Transmission Provider apply the ERAS process for such project.

2. An executed agreement evidencing that the projects submitted for ERAS processing is intended to be used by the entity with the claimed resource adequacy and/or reliability need. Such agreement shall take one of the following forms:

a. A Load Serving Entity acknowledgement to self-supply;
b. A Power Purchase Agreement (PPA) or similar off-take agreement between the Interconnection Customer submitting the project for ERAS consideration and the entity with the load to be served (including, but not limited to, an Alternative Retail Electric Supplier or its Load Serving Entity);
c. An agreement that calls for the Interconnection Customer to develop the Generating Facility described in the Interconnection Request and subsequently transfer ownership or control of such Generating Facility (Build-Own-Transfer Agreement) to the entity with the load to be served (including, but not limited to, an Alternative Retail Electric Supplier or its Load Serving Entity); or

d. Other agreement between the entity submitting the Interconnection Request, including the RERRA verification letter as appropriate, and the entity with the load to be served (including, but not limited to, an Alternative Retail Electric Supplier or its Load Serving Entity), stating that the ERAS project will be used to meet an identified resource adequacy deficiency.[138]

There are several aspects of the RERRA language that MISO is proposing to add to its Tariff and that MISO wishes to highlight. First, the RERRA, where the load will be located, must verify to MISO that the new, incremental load addition is valid and is not currently included in a plan or other procedure under the RERRA's purview or the Generating Facility will address an identified resource adequacy deficiency within that RERRA's footprint.[139] The verification may take any form that works for a specific state, but it must be made by a RERRA or a RERRA's designated representative, and it must be submitted in writing to MISO. MISO changed the details of this requirement to better target the resource adequacy driver the ERAS project is addressing and to ensure that the RERRA verifies that project will address a new load addition or resource adequacy deficiency in its footprint. The ERAS construct is a vehicle intended to achieve a narrow but important purpose: address near-term resource adequacy and/or reliability need claimed by an Interconnection Customer in a RERRA. Requiring that the RERRA verify to MISO that there is a valid, new, incremental load not already planned for or that the proposed project will address an identified resource adequacy deficiency is critical to maintaining this limited scope. Assuming the proposed project meets all the other ERAS requirements, MISO will accept the RERRA's verification and the project will be processed accordingly.

As for the second section of the RERRA language, applicants are still required to provide an executed agreement evidencing that the project submitted for ERAS is intended to be used by the entity with the claimed resource adequacy or reliability need, MISO added this language to ensure that any proposed ERAS project is directly tied to a specific load need. The executed agreement ensures that the project is one that the entity with the load to be served plans to use to address the need, and not simply a speculative project whose developers do not have any commercial arrangement to satisfy the need.[140] For example, an Interconnection Customer that has an agreement with a data center developer for the generation to serve that load is differently situated from a group of Interconnection Customers who are entering the queue with the hope of pitching their generation project to the developer. If the proposed ERAS projects do not meet

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138 *See* Tab A Redlines, GIP Section 3.9.1.

139 *Id.*

140 Witmeier Testimony at 7:3-5, 41:1-3, 41:17-23, 42:1-2.While such optimistic submissions may be features of Interconnection Requests submitted into MISO's Definitive Planning Phase ("DPP"), these contribute to a high volume (and high drop out rate) of Interconnection Requests in the queue. ERAS is intended to have a narrower scope and be used by highly certain projects addressing urgent needs.

these requirements as well as the other ERAS eligibility requirements, then they may submit their project to the generator interconnection queue. This requirement pairs the proposed project with a specific need, mitigating overuse concerns.

Collectively, these requirements narrow ERAS projects to only those for which a claim of need is stated, for which the applicable RERRA has provided verification that there is a valid, new, incremental load not already planned for or that the proposed project will address an identified resource adequacy deficiency, and for which an executed agreement exists connecting that need to the specific project. MISO also added a third section to the RERRA language to incorporate the retail states—Illinois and a portion of Michigan—into the ERAS process to address resource adequacy deficiencies in those states.[141] The proposed language states that if an Interconnection Customer's new Generating Facility will serve a retail choice load then the Interconnection Customer will need to submit demonstration of the resource adequacy deficiency, but will not be required to include a written verification from a RERRA.[142] Rather, MISO will notify the respective RERRA in the retail state that an Interconnection Request was submitted requesting processing in ERAS and will send a copy of the request to the relevant RERRA. The RERRA will then have 10 business days from receipt of the notification from MISO to state that the Interconnection Request should *not* be considered in the ERAS process.[143] This proposal recognizes that these areas do not have to seek approval from their RERRA and recognizes the existence of Alternative Retail Electric Suppliers in these areas as other entities that serve load. Thus, the new proposal better facilitates use of the ERAS process in Illinois and the retail sections of Michigan without changing the role or requirements applicable to RERRAs in other parts of MISO's footprint.

To recognize and reflect the states' authority over resource adequacy, MISO retained the language indicating that a RERRA's written verification to MISO regarding a proposed ERAS project "was not intended to constitute or provide evidence of any final determination of need or suitability of the project for any purpose by the issuing entity" beyond requesting that MISO apply the ERAS process to the project.[144] MISO understands that each RERRA has a distinct and separate regulatory process for the approval of energy projects within its jurisdiction and did not want participation in the ERAS process to be interpreted as MISO *directing* the RERRA to approve certain projects over others. It also ensures that the notification does not pre-determine any outcome of an applicable state process. Even if a project is approved to participate in ERAS, the LSE or developer must still receive state approval through the state's corresponding regulatory review process whether that be before the state public utility commission or the RERRA. MISO is simply proposing ERAS as a tool that may be utilized to address short-term

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141 *See* Tab A Redlines, GIP Section 3.9.1.

142 *Id.*

143 *Id.*

144 *Id.*

resource adequacy and/or reliability needs—the states are not required to participate in or to utilize ERAS.

3. Establishing a Stronger Nexus to Resource Adequacy Deficiencies

In its ERAS order, the Commission also found that MISO's proposal did not "sufficiently describe how the ERAS process is sufficiently targeted to study only interconnection requests needed to meet the anticipated shortfall in generating capacity described by MISO."[145] The Commission also pointed to PJM utilizing its locational deliverability areas and CAISO's system need criterion to target the proposed projects to areas with resource adequacy and/or reliability needs.[146] To better establish the nexus between the load need and the ERAS project, MISO is now requiring that the proposed ERAS project and the load addressing the resource adequacy and/or reliability need be located in the same Local Resource Zone ("LRZ").[147] This will ensure that the generation will support Local Clearing Requirements ("LCR"), and prevent ERAS projects from driving import or export concerns if the ERAS project is located in a different zone, unless the project applicant can demonstrate that the use of a Generating Facility not in the same LRZ was included in a resource filing or other submission made to the RERRA. MISO has ten geographic areas that are identified as Local Resource Zones and generally consist of one state or portions of several states.

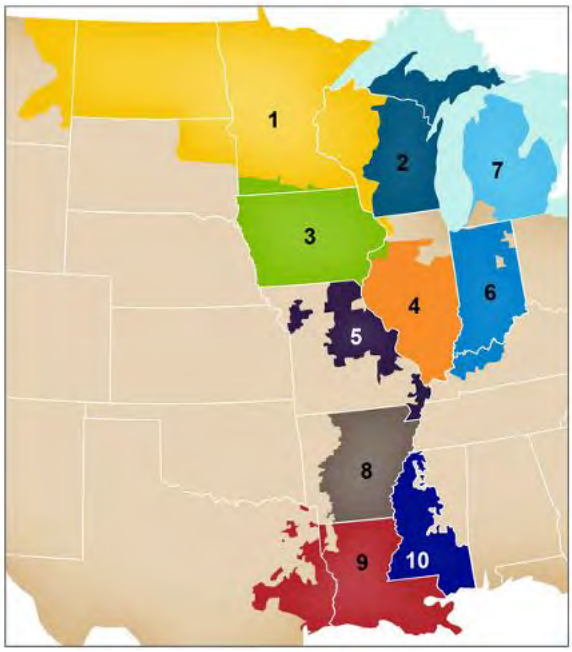
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[145] ERAS Order at P 201.

[146] *Id.* at P 202.

[147] Witmeier Testimony at 4:10-15, 30:10-16, 32:4-16, 41:14-15, 61:17-19.

Figure 3: MISO Local Resource Zones[148]



MISO recognizes that that some LSEs span multiple LRZs and that LSEs regularly rely on resources from other zones to support their load requirements. MISO is requiring that the ERAS project be within the same LRZ as the load it is addressing unless the project applicant can demonstrate that the use of a Generating Facility not in the same LRZ was included in a resource filing or other submission made to the relevant RERRA.[149] Thus, if the ERAS project is located outside of the LRZ where the load need is located, then it will need to provide an Integrated Resource Plan ("IRP") or a comparable document that has been filed with the RERRA with its ERAS application.[150]

When applying to ERAS, the Interconnection Customer must identify the specific load addition and/or resource adequacy deficiency that the project will address including the project location and the expected MW value. The project must also not exceed 150% of the identified need based

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148 Tariff FERC Electric Tariff, ATTACHMENT VV, *Map of Local Resource Zone Boundaries*, available at: https://docs.misoenergy.org/miso12-legalcontent/Attachment_VV_-_MAP_of_Local_Resource_Zone_Boundaries.pdf.

149 Witmeier Testimony at 4:10-15, 30:10-16, 32:4-16, 41:14-1516.

150 Witmeier Testimony at 30:10-16.

on interconnection service.[151] MISO recognizes that other RTOs have utilized accredited capacity limitations, but since accredited capacity depending on the fuel type can be lower than 100% for many resources, MISO's limitation is aimed at tightening the nexus between the need claimed and what facility is being built without creating different rules for different resource types. This will enable MISO to better establish a connection between the identified load need and the ERAS project while also limiting the amount of service that may be requested to address the load need plus a reasonable margin. This methodology will facilitate the efficient implementation of ERAS and is not an overly complicated formula for determining the amount of need the ERAS project may address.[152] These revisions ensure a stronger tie between the ERAS project and the resource adequacy deficiency that it is addressing.

4. Increasing Transparency in the ERAS Process

MISO understands that this is a unique process that is being implemented for a very specific purpose but is committed to being transparent about the projects that participate in ERAS. While refining the ERAS proposal, MISO is making several changes to the ERAS application in order to increase transparency in the process. MISO plans to publish an ERAS webpage that will provide a significant amount of information regarding each ERAS project. To that end, an ERAS Interconnection Request must identify the claimed resource adequacy and/or reliability need(s) for which it is being submitted. This must include the location of the project—i.e. the county and state of the Generating Facility site, the electrical bus location(s), and the Local Resource Zone. The ERAS Interconnection Request must identify the load to be served via the off-take agreement as well as the peak demand for electricity in MWs as the amount of Interconnection Service requested must not exceed 150% of the identified MW need, and the location of the load to be served (i.e. the county and state, and the Local Resource Zone).

As part of the ERAS application, project applicants are also required to include a non-confidential summary of information that MISO can publish on its webpage. The required information that will be provided by the project applicant must include the following: the developer proposing the ERAS project, the MW range of need the ERAS project is addressing, the LRZ region where the ERAS project is located, and a general description of the driver of the load need (i.e., data center, manufacturing plant, etc.). MISO will also publish the RERRA that submitted a verification for each ERAS project, the specific carve out the project falls within, and the specific ERAS quarterly study cycle that the proposed project will be studied in once MISO has completed its screening process per ERAS cycle.

MISO is committed to ensuring that information about the ERAS process is easily accessible both for potential project applicants but also for other stakeholders in the energy industry. MISO also plans to publish an informational guide for potential ERAS applicants that addresses many

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

[152] Witmeier Testimony at 43:1-19, 42:1-2.

common questions and problems that an applicant might be faced with when submitting its ERAS project. MISO believes that providing numerous cycles for ERAS projects to participate in will ensure that the ideal projects are proposed for ERAS and that potential project applicants have time to fully prepare their project before applying.

B. The ERAS Process is Balanced and Narrowly Tailored

ERAS was crafted to target projects that can meet resource adequacy and reliability needs quickly while also maintaining developer, fuel, and technology neutrality. MISO developed this filing based on its determination of how to best address its resource adequacy needs given its unique make up of primarily vertically integrated utilities across many different state and RERRA jurisdictions. The revised filing now incorporates the retail states so that all states in the MISO footprint may participate in ERAS. The LRZ requirement ensures that the ERAS project is located in the same area as the load need but also provides an exception for Generating Facilities not in the same LRZ that are included in a resource filing or other submission made to the relevant RERRA. State and RERRA involvement in ERAS ensures that the proposed ERAS projects are necessary to meet resource adequacy and reliability needs while also not favoring one kind of project or project developer.

These proposed revisions are properly tailored to ensure that projects capable of addressing identified resource adequacy or reliability needs participate in the ERAS process. Moreover, the new ERAS quarterly project processing cap will ensure that the projects are spread over a longer time period, which allows for the studies to be completed on a regular cadence and allows MISO to better forecast its internal resource and employee needs. Due to these changes, ERAS will not risk "replicating the same backlogs and delays plaguing MISO's existing generation interconnection queue, which are what put MISO in its current situation in the first place."[153] This revised proposal has "practical limits on the volume of interconnection requests that will be studied, such that the proposal is tailored to meet the identified resource adequacy and reliability needs."[154]

The following section first describes the eligibility requirements that projects are expected to meet to participate in ERAS. These eligibility requirements are critical for ensuring that the projects that are studied in the ERAS process are truly "shovel ready" and can be implemented in the very near term. The section then explains how the refined ERAS proposal ensures that ERAS projects will not harm existing projects in the general interconnection queue and how the ERAS project cap is a further safeguard to that end. MISO is committed to ensuring this process works for as many stakeholders as possible while also addressing the near-term resource adequacy and reliability needs in its footprint.

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[153] ERAS Order, Comm'r Rosner concurrence at P 1.

[154] *Id.*

1. ERAS Has Strict Eligibility Requirements

Over the past several years, MISO has pursued numerous avenues to address its near-term resource adequacy issues including improving GIP procedures, implementing a queue cap, and making other queue improvements, but the benefits of these updates will be unable to address or fill the identified resource gap in the short-term.[155] The continued large volumes of Generator Interconnection requests and accumulating backlog have delayed resource additions from obtaining executed GIAs. These delays are exacerbated by supply chain bottlenecks, permitting delays, and other commercial challenges that plague projects in the queue and those with signed interconnection agreements. The current queue cycle takes 3-4 years and late-stage dropouts from 2020-2022 resulted in queue re-studies and prevented the processing of later cycles. Concurrently, states are seeing extreme load growth due to economic development and new, large spot load additions but lack the ability to quickly add new resources.[156] To address this clear and immediate need, ERAS was created to facilitate the completion of projects that are "shovel ready"—projects that can truly address the shortfalls identified by numerous load forecasts.

To that end, MISO is implementing stringent eligibility requirements for participation in ERAS to only allow projects that are commercially viable within the next few years. In addition to the requirements addressed in the previous section—the RERRA notification and executed agreement—proposed ERAS projects must also meet other eligibility requirements. First, to participate in ERAS, an Interconnection Customer must pay a non-refundable application fee of $100,000, a milestone M2 payment of $24,000 per MW, and, upon signing the EGIA, agree to pay for any associated network upgrades even if the project is ultimately withdrawn from ERAS. The purpose of these financial requirements is to minimize the number of speculative projects applying to ERAS and to ensure that the projects that are applying truly are ready to be built and will serve an identified need.[157] Second, MISO is requiring that an ERAS project's EGIA commercial operation date be within three years of project submission. This requirement is focused on identifying the projects that are truly "shovel ready" and can be fully operational in the next five years.[158] Third, an ERAS project must also be able to demonstrate 100% Site Control for the generator and point of interconnection upon submission to MISO. All evidence of Site Control must be supplied at the time the ERAS application is submitted to MISO.[159] Finally, ERAS

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[155] Witmeier Testimony at 8:3-21, 9:1-2.

[156] *Id.*

[157] *Id.*

[158] *Id.*

[159] *Id.*

projects must meet capacity resource requirements and therefore must request Network Resource Interconnection Service (NRIS).

Since MISO's intent in establishing ERAS is to identify projects that are able to address resource adequacy and/or reliability needs in the short-term, existing projects that have not reached Decision Point II ("DP2") in the 2022, 2023, and later cycles will be eligible to transfer to ERAS.[160] MISO is currently aware of several existing projects in the generator interconnection queue that could apply to participate in ERAS and have plans to consider that option.[161] Existing projects may remain in the DPP cycle while applying for ERAS, but once admitted to ERAS, the projects must withdraw from the DPP cycle and will be subject to Automatic Withdrawal Penalties and Harm Penalties.[162] MISO is requiring these penalties because it recognizes that when projects drop out of the generator interconnection queue, the withdrawal causes harm to the other projects in the cluster. Moreover, after applying, if the existing project is deemed ineligible to participate in ERAS process, then it will forfeit the $100,000 D1 payment provided with the ERAS application and remain in its original queue position.[163] When an existing project leaves the DPP process and successfully transfers to ERAS, it becomes a new Interconnection Request. Therefore, modifications may be made to the project at the time of application. Modifications are allowed to better tailor the Interconnection Request to the claimed need. Any transfers into ERAS is made under new Interconnection Request and is technically not tied to the original request.[164]

Limiting each ERAS cycle to 10 projects will allow MISO to study each project individually in the order submitted, rather than as a group.[165] This serial approach will also allow the developer to perform their own initial studies without the uncertainty of what other generation projects will be in the study as well. Enabling serial studies of the proposed projects is a key feature of ERAS. It affords ERAS Interconnection Requests a better understanding of their impact on the system when looking to address the load need. The traditional challenges related with reviewing projects on a serial basis are not present with ERAS because there will be a much smaller number of Interconnection Requests to process and they are expected to be geographically and

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[160] Witmeier Testimony at 15:5-17.

[161] Witmeier Testimony at 15:18-21.

[162] These penalties are outlined in Attachment X, Sections 7.6.2.1.1 and 7.8 respectively.

[163] Witmeier Testimony at 15:21-23, 16:1-4.

[164] *Id.*

[165] *Id.*

electrically dispersed across the MISO footprint.[166] This is distinguished from the DPP queue where serial studies are difficult, if not impossible, due to the extremely high number of applications per cycle and the high probability of those projects being in the same area.[167] If several ERAS projects in the same quarterly study cycle are located in the same geographical area or impact the same constraint, then MISO will study the project with the earliest submission time in that cycle, and will study the second request in the next available ERAS quarterly study cycle. However, MISO is not anticipating that this will occur very often due to the project cap per cycle, its large geographic footprint, and the strict eligibility requirements to participate in ERAS.[168]

Regarding Affected Systems Studies ("AFS"), neighboring systems will have the right to evaluate the impact of ERAS projects on their systems, just as with projects in the DPP. Any ERAS project that meets JTIQ criteria will be subject to JTIQ.[169] Where available, the affected system study Network Upgrades will be documented in the EGIA. Where AFS analysis is not available for inclusion in the final EGIA, the EGIA will be executed by all parties and MISO will provide any updated analysis when received from the applicable Affected System. But ERAS projects will still be responsible for all required Network Upgrades even if the ERAS project ultimately ends up terminating the EGIA.[170] MISO's proposal includes Tariff language to reflect that even if MISO only provided an estimate of potential network upgrade costs upon applying to ERAS, there will be a true up where either MISO would refund an overcollection of costs or the Interconnection Customer would pay the difference to meet the actual network upgrade costs.[171] MISO added this requirement to ensure that the ERAS project remains responsible for AFS costs. MISO is dedicated to protecting the Generator Interconnection Queue and views this requirement as a further guardrail to protect active projects in the DPP while ensuring that only eligible, ready projects are processed through ERAS.

Finally, to reflect that ERAS is a short-term solution for a near-term problem, MISO is requiring that ERAS projects have a COD three years after the project's submission date unless the project was deferred to a later quarterly study cycle. This caveat is necessary to insulate Interconnection Customers from the impact of deferrals due to the operation of the quarterly study cap. MISO has also written a sunset date for ERAS into the Tariff. ERAS will sunset by August

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[166] MISO processes hundreds of Interconnection Requests through its DPP each year with 600 in its 2023 cycle. Based on extensive discussion with RERRAs and other stakeholders, MISO projects fewer than twenty projects will qualify for ERAS in 2025.

[167] Witmeier Testimony at 5:16-19.

[168] *Id.*

[169] *See* Tab A Redlines, GIP Section 7.3.2.3.1.

[170] Witmeier Testimony at 6:12-16, 34:8-15.

[171] *See* Tab A Redlines, GIP Sections 3.9.6, 3.9.6.1, 3.9.6.2, and 3.9.6.3.

31, 2027, or when it has completed 68 ERAS Interconnection Request studies, whichever occurs first.[172] MISO made this requirement narrower in response to stakeholder feedback as well as Commission feedback stating that MISO's original ERAS proposal was unlimited in nature.[173]

MISO has implemented these stringent eligibility requirements for ERAS to ensure that the projects participating in it are truly "shovel ready" and capable of addressing the states' resource adequacy and/or reliability needs in the near-term. The ERAS eligibility requirements act as a filter to restrict ERAS entry to only those projects that are commercially ready, are needed to respond to a specific resource adequacy or reliability problem and can be completed in the next few years.

2. The Cap Will Expedite ERAS Studies and Prevent Harm to the Queue

A significant concern that was identified in the process of crafting ERAS is the impact ERAS will have on the other queue studies. ERAS has been cautiously crafted to avoid supplanting the DPP or harming projects in the queue. MISO worked carefully to address these concerns and emphasizes its commitment to prioritizing the use and improvement of MISO's generator interconnection queue. Projects in the generator interconnection queue will not be competing with ERAS projects for transmission capacity because although both ERAS and DPP projects will utilize the same MTEP base case, they will have different generator assumptions.[174] ERAS will include only approved Generating Facilities, where the DPP will include all queued projects which includes a significant amount of speculative projects.[175]

As Andrew Witmeier explains in his direct testimony attached to this letter, before every ERAS cycle, all Interconnection Requests with a GIA approved since the last base case was created will be added to the base case for the following ERAS cycle but they are not included in any ongoing DPP studies.[176] The base case for each DPP cycle is never updated once the study process is kicked off except for generation changes due to Interconnection Request withdraws or generator retirements.[177] This ensures that the transmission capacity made available for DPP projects is not

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[172] *Id.* at Section 3.9.9.

[173] *See* Tab A Redlines, GIP Section 3.3.1; ERAS Order at P 203.

[174] Witmeier Testimony at 17:9-19.

[175] *Id.*

[176] *Id.*

[177] *Id.*

being taken away by ERAS Interconnection Requests approved outside of the DPP cycle.[178] This also insulates existing DPP projects from negatives impacts or cost shifts due to the existence of the ERAS process.[179]

By providing ERAS as a tool for the states to utilize, MISO is not looking to displace or overshadow the generator interconnection queue, rather it is providing a process to address a near-term, identified resource adequacy need. The ERAS eligibility requirements are more rigorous than the DPP requirements and are capped both in total number of projects and number of study cycles, which ensures a smaller applicant pool of more earnest project applicants for ERAS and maintains the integrity of the generator interconnection queue. A comparison of the different eligibility requirements is included below.

C. The ERAS Process is Not Unduly Discriminatory and is Consistent with Open Access Requirements

In Order Nos. 888 and 2003, FERC aimed to prevent the discriminatory treatment of competitive generation by requiring open access transmission tariffs that are not "unduly discriminatory or anticompetitive" and that "offer third parties access on the same or comparable basis, and under the same or comparable terms and conditions …."[180] MISO's refined ERAS proposal remains in alignment with those requirements—it is not unduly discriminatory, it is not anticompetitive, and it provides third parties with access to the transmission system on the same or comparable basis. This section first explains why the ERAS proposal is not unduly discriminatory and then addresses how ERAS meets FERC's open access requirements.

1. ERAS is Not Unduly Discriminatory

There is no restriction on the type or sponsor of projects that can apply to the ERAS process, which makes the application process non-discriminatory. MISO has also created carve outs to the total project cap for applicants that are uniquely situated like Independent Power Producers and developers serving retail choice states. These carve outs will allow these groups of applicants to participate on equal footing with other applicants proposing ERAS projects and must meet the same eligibility requirements to participate in ERAS. MISO added the carve out for IPPs to address concerns that LSEs had an advantage over other entities when submitting projects to

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178 *Id.*

179 *Id.*

180 Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,647. *See also Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, FERC Stats. & Regs. ¶ 31,146 (2003), *order on reh'g*, Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160, *order on reh'g*, Order No. 2003-B, FERC Stats. & Regs. ¶ 31,171 (2004), order on reh'g, Order No. 2003-C, FERC Stats. & Regs. ¶ 31,190 (2005), *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC*, 475 F.3d 1277 (D.C. Cir. 2007), cert. denied, 552 U.S. 1230 (2008).

ERAS. The carve out for the retail states also enables developers in those areas to participate in ERAS and set aside a portion of the projects to ensure they are able to participate.

Initially, MISO proposed only allowing LSEs, and those contracting with LSEs, to apply for ERAS. After receiving stakeholder feedback on this point while preparing its original ERAS filing, MISO expanded ERAS to allow any applicant to apply to ERAS as long as the applicant had an executed agreement for a specific load need. Under the revised ERAS process, an Independent Power Producer ("IPP"), LSE, or developer may apply to ERAS.[181] MISO's proposal to enable IPPs with an LSE offtake agreement to apply for ERAS addresses the unduly discriminatory concerns identified by the stakeholders and the 10 project carve out enables further participation for IPPs. Some stakeholders have protested that this is still favoring LSEs over other kinds of applicants and thus assert that ERAS is unduly discriminating against non-LSE participants. MISO disagrees. MISO has expanded the applicant pool to include developers that have contracted offtake agreements with a LSE to propose ERAS projects and added project cap carve outs to enable further participation by those IPPs that prefer to contract with the load source directly rather than the LSE. ERAS projects submitted by IPPs that have contracts with the LSE will not count towards the ten project cap. Thus, the ten project carve out exists to create a space designated specifically for IPPs, thus addressing concerns that LSEs may exhaust the ERAS cap before IPPs can submit their projects. This approach balances enabling broader participation with the need to ensure that ERAS does not become a general purpose alternative to the DPP or grow beyond a limited number of projects. Any Interconnection Customer that has a project that they believe is the most cost effective, ready, or best positioned resource to respond to an urgent resource adequacy need is encouraged to apply to participate in ERAS.

Under the revised ERAS proposal, developers will have comparable access to the ERAS process and may also execute commercial arrangements with load. Any other differences for project applicants are neither created nor exacerbated by MISO's Tariff.[182] The purpose of ERAS is to encourage the submission of projects that have been identified as responsive to a need and can be completed rapidly. Although MISO has previously stated that requiring executed agreements does not necessarily prove project readiness,[183] the executed agreement requirement serves a different purpose and provides additional value in the context of this filing. Specifically, requiring executed agreements for ERAS effectively ties the project to the claimed resource adequacy and/or reliability need. The process of securing the necessary agreements and acknowledgment by the RERRA may be competitive. The ERAS process simply moves that competition and development of commercial certainty to before the Interconnection Request is submitted, rather than while it is in queue. MISO has actively worked to reduce the risk of

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[181] Witmeier Testimony at 39:18-23, 1-7.

[182] ERAS offers a level playing field and contemplates that IPPs may be the entities that secure the agreement and RERRA notice for a given need.

[183] MISO Initial NOPR Comments, Docket No. RM22-14-000 (October 13, 2022).

speculative projects participating in ERAS and requiring executed agreements is one way to ensure that.

In addition to expanding the different kinds of applicants that can participate in ERAS, MISO is also allowing existing projects in the Generator Interconnection Queue to transfer to ERAS.[184] In the original ERAS filing, several stakeholders argued that ERAS would result in the unequal treatment of participants who have dutifully followed the traditional interconnection process. But MISO is allowing any existing projects to transfer to ERAS if the project is not past Decision Point II ("DP2"). MISO is prohibiting transfers after DP2 to protect the remaining projects in the queue by preventing any unplanned re-studies that could result from any late-stage transfers.[185] Also, MISO is requiring that existing projects that do transfer to ERAS pay all relevant withdrawal penalties in addition to making the non-refundable $100,000 D1 payment to participate in ERAS.[186] Due to these high financial stakes and the strict eligibility requirements for ERAS, MISO is not anticipating many transfers from the DPP process. Some stakeholders wanted greater transferability from the DPP to ERAS, MISO's proposal however reflects the compromise of protecting the existing queue while providing projects with the opportunity to transfer from the DPP to ERAS.

In addition to the different eligibility requirements between ERAS and the DPP process, MISO plans to coordinate the ERAS, EPR, and DPP studies to maximize efficiency and reduce any impact on each other.[187] MISO expects protestors to claim that the ERAS process will negatively impact existing projects that are currently included in the Generator Interconnection Queue. At numerous stakeholder meetings during the original ERAS filing, MISO stressed that this was not the case due to the way in which the studies are completed. The base case for MTEP, EPR, and ERAS projects is updated with all GIAs approved to date. Approved MTEP projects can be utilized for constraint mitigation in DPP, EPR, and ERAS projects studies. Additionally, Network Upgrades that are identified in ongoing MTEP studies that mitigate congestion in DPP and ERAS studies will remove the need for DPP and ERAS network upgrades once the MTEP project is approved.[188] Finally, ERAS projects will not harm projects currently studied in the DPP process by taking existing transmission capacity headroom from active projects ERAS and DPP use the same MTEP base case as a starting point and any headroom used by ERAS projects is not

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[184] Witmeier Testimony at 15:5-17.

[185] These projects are the ones that would receive the least benefit from ERAS given their degree of advancement through the DPP.

[186] Witmeier Testimony at 15:21-23, 16:1-4.

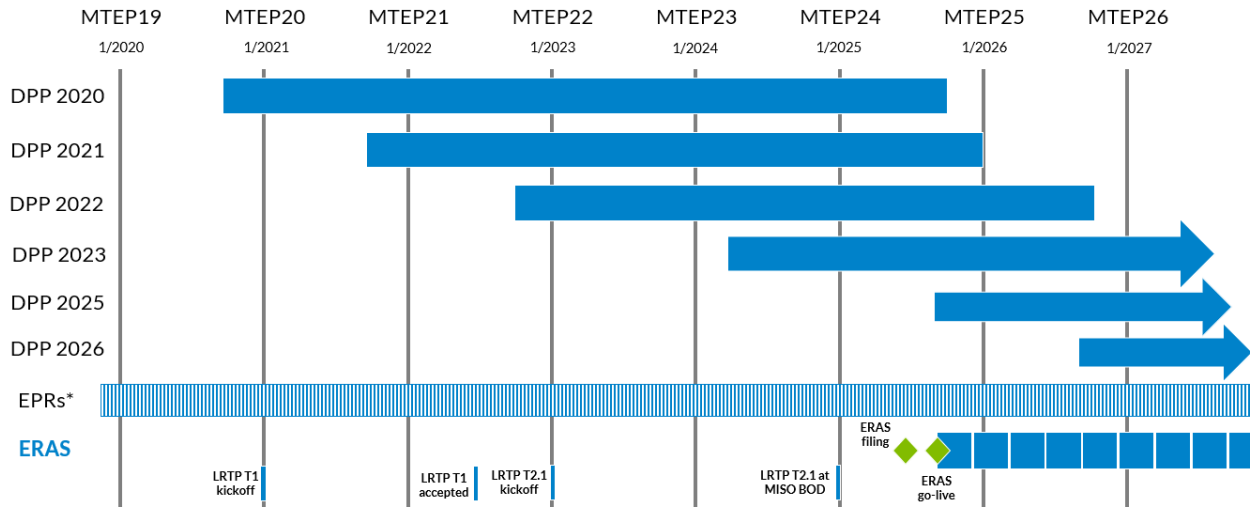
[187] The DPP is primarily described in section 7 of the GIP. See Tariff, Attach. X, GIP Section 7.

[188] *See* MISO BPM 15, Section 6.1.1.1.

deducted from the DPP model.[189] The output of the DPP and ERAS models are then reconciled in the next MTEP. This is consistent with how MISO reconciles currently effective parallel processes through the next MTEP base case. Thus, while it may be possible for over-allocation of capacity headroom to occur, this would not impact DPP projects and would be addressed through MTEP. Thus, ERAS projects will not have early access to newly available headroom related to Tranche 2.1 and will not disadvantage projects from 2025 queue cycle.

The chart below demonstrates the ongoing queue study cycles and the projects in those cycles are still using the transmission capacity that was available in the system at the time that model study started. If MISO approves an ERAS project that will utilize the transmission capacity in MTEP 24 and the DPP 23 is using MTEP 23, ERAS will not take away transmission capacity from any project in the 2023 queue cycle. Ongoing queue cycles interact with each other, but do not take transmission capacity or headroom from each other. Thus, ERAS projects will not take away transmission capacity for ongoing DPP cycles as the base case is not updated. Any overallocation that may occur will be identified and mitigated in the next MTEP cycle.

Figure 4: ERAS Will Integrate With Existing Study Processes[190]



ERAS provides all interconnection customers with a comparable opportunity to submit an interconnection request and compete to be studied under MISO's ERAS interconnection procedures. ERAS treats participants equally as long as they meet the eligibility criteria. All

189 Witmeier Testimony at 17:9-19.

190 *Expedited Resource Adequacy Study (ERAS) Workshop* at 10, (December 6, 2024), https://cdn.misoenergy.org/20241206%20Expedited%20Resource%20Adequacy%20Study%20(ERAS)%20Workshop665747.pdf.

ERAS applicants will be subject to the same rules and requirements on a comparable basis, regardless of fuel type, technology, or any other factors.

2. ERAS is Consistent with Open Access

MISO's interconnection procedures are part of an open access transmission tariff and thus MISO must offer access to the generator interconnection process on the same or comparable basis. Unlike some stakeholder assertions, ERAS is not providing priority access to its generator interconnection process for an exempted class of interconnection requests. The ERAS process is open, competitive, technology/fuel agnostic, and does not involve MISO favoring or selecting certain projects over others. This includes existing projects in the queue as MISO is not harming Interconnection Customers in the generator interconnection queue by using available headroom on the transmission system.

Once a project has met the strict eligibility requirements for ERAS, including the RERRA verification, it is allowed to participate in the ERAS process. Due to the jurisdictional split between the FERC and the states over resource adequacy and reliability, MISO's role is not to be in the middle of resource decision-making processes of the states or RERRAs.[191] Unlike PJM's Resource Reliability Initiative ("RRI") which clearly prioritizes projects on the ELCC Class Ratings, MISO is not going rank ERAS projects. The ERAS process does not unduly discriminate against or in favor of any type of resource or pre-existing project, which is unique from the PJM and CAISO's proposals that favor certain projects by giving higher weights to resources that are more reliable and consistent.[192] PJM's RRI process is aimed at enabling "a very limited injection of 50 projects that score high in measures PJM has identified as contributing to addressing reliability needs."[193] PJM specifically noted that 60% of its Transition Cycle #2 were intermittent resources but asserted its need for high-reliability value projects to meet its near-term resource adequacy needs.[194] Despite PJM's clear preference for certain kinds of projects that are not intermittent and placing a limit on the total number of projects that can participate, the Commission approved their proposal.[195]

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191 *See* 16 U.S.C. § 824(b)(1).

192 *PJM Interconnection, L.L.C.*, Docket No. ER25-712-000, PJM's Transmittal Letter (filed Dec. 13, 2024) ("PJM's RRI Transmittal Letter"); *California Independent System Operator Corporation*, Docket No. ER24-2671-000, CAISO's Transmittal Letter (filed Aug. 1, 2024).

193 PJM's RRI Transmittal Letter at 3.

194 *Id*.

195 *PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,084 at P 78 (2025). PJM awards 55 out of a possible 100 points for two attributes: unforced capacity ("UCAP") and effective load carrying capacity ("ELCC") that tend to favor certain, non-intermittent resource classes over others.

While the refined ERAS process is implementing a project cap, MISO will not rank or score submitted projects and is open to any applicant and any fuel source as long as the project meets ERAS eligibility requirements. Open access requirements and the states' jurisdiction over resource adequacy are not mutually exclusive. In the revised ERAS proposal, MISO is still not weighing any class of resources over others but rather is prioritizing projects that can be completed in the near-term to address specific looming resource adequacy shortfalls. MISO is also not sorting winner or loser ERAS applicants based on the specific attributes of each generating facility. Rather it is deferring to state jurisdiction over resource procurement and facilitating the identification of projects that will be completed in a short time period to address resource adequacy and reliability needs. The states can determine the best form of capacity that will meet their needs through the ERAS process. The ERAS process will also mitigate many of the identified co-location concerns heard in the industry as states will have the ability to quickly address large spot loads.[196]

In the original ERAS filing, some stakeholders asserted that ERAS violates open access by preferring certain LSE/RERRA-sponsored projects or that ERAS treats participants unequally by granting undue advantages to projects owned by LSEs. Many of the refinements made to the original ERAS filing address those complaints and aim to equalize the playing field between applicants. MISO's proposed Tariff language is clear that *any* Interconnection Customer may submit an ERAS project if it meets the requirement of supplying an executed agreement.[197] A non-LSE related Interconnection Customer could submit an agreement with a particular load that their generation will serve.[198] The RERRA will continue to have its applicable regulatory oversight over the LSE and still must verify the new, incremental load addition claimed by the Interconnection Customer is valid and not otherwise included in a resource plan or other process under the RERRA's purview or the Generating Facility will address a resource adequacy deficiency before the project can participate in ERAS.

Thus, the ERAS process treats all applicants on a comparable, not unduly discriminatory, basis that is consistent with FERC's open access requirements, subject to the ERAS eligibility requirements, which are applied uniformly across all applicants.

D. Substantial Evidence Supports the Need for ERAS

Substantial evidence supports MISO's need for ERAS. MISO has created ERAS to work in parallel with the DPP process to provide a process for non-speculative, shovel ready projects to be completed in 3-5 years. The ERAS process incorporates the states' primacy on resource adequacy while providing a pathway for those projects to be completed on an accelerated basis.

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196 *See* Co-Location Order, 190 FERC ¶ 61,115 (2025).

197 *See* Tab A Redlines, Section 3.9.1.

198 *See id.*

MISO's refined ERAS proposal addresses a real need that has been identified in numerous load forecasting reports, by the states, and in MISO's own experience as an independent system operator.[199] MISO's experience with a quickly changing industry and load growth is being witnessed across the country and by many other entities in the industry that have discussed similar experiences at technical conferences hosted by FERC including the recent conference on co-location.[200] Comments made during FERC's technical conference on resource adequacy recognized that there is a reliability crisis and that generators need to come online in the very near term to address the looming resource adequacy needs.[201] MISO recognizes these concerns and is working expeditiously to make changes to address those needs in the near-term. The supporting evidence demonstrates that the benefits of the current queue improvement mechanisms will take longer than is necessary to address the near-term resource adequacy needs.[202] The GIP improvement mechanism will improve the quality of the projects entering the queue, the Cap mechanism will address the quantity of projects entering the queue, and ERAS will supply the states with a mechanism to address resource adequacy and reliability needs in the next few years. The proposed ERAS revisions will benefit Interconnection Customers and other interconnection process participants by supplying a way for commercially ready, necessary projects to obtain a GIA quickly to address resource adequacy and reliability issues within the MISO footprint.

The original ERAS process was extensively reviewed and discussed in the stakeholder process and MISO adopted many stakeholder suggestions to ensure the process achieves what it aims to do.[203] The refined-ERAS procedures will ensure that Interconnection Customers applying to participate have projects that are ready to be completed.[204] MISO needs an effective tool to address resource adequacy and reliability needs now, which is why it worked expeditiously to refine its previous ERAS process and is now proposing an updated process that can be executed in a few months. By implementing the strict eligibility requirements, ERAS will increase certainty for Interconnection Customers by ensuring that all ERAS projects are "shovel ready" and are required to pay for any associated Network Upgrades even if they end up ultimately dropping out

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199 *See supra* notes 51-87; *see also*, Tab C, Direct Testimony of Andrew Witmeier.

200 *See supra* Section II.B.

201 *See supra* note 80.

202 2024 Cap Filing at 17 ("Although MISO's recent queue reforms contained many important measures to enhance the current queue process, these measures are expected to work over a period of time and may not allow MISO to immediately address the identified queue issues for the 2023 DPP cycle and reduce study cycle volume to a level that supports studies using realistic assumptions.").

203 *See supra* Section II.C.

204 *See supra* Section III.B.

of the process.[205] ERAS was carefully crafted to ensure that existing projects in the Generator Interconnection Queue will not be affected by the ERAS process, nor will those projects lose out on existing transmission capacity this is especially true now that MISO has capped the ERAS process to 68 projects total spread out over multiple cycles.[206] The existing queue will remain a priority for MISO. MISO does not view ERAS as infringing upon or negatively affecting the existing queue, but rather as an additional tool for states to utilize if eligible.

Establishing a separate process for projects addressing resource adequacy and/or reliability needs is not an unfamiliar concept at FERC. As it noted in the original ERAS Order, the Commission previously accepted similar proposals from CAISO and PJM.[207] MISO recognizes that the other RTOs utilized some form of a scoring matrix for proposed projects and that ERAS does not involve a similar methodology. Due to the states' responsibility for resource adequacy within their borders, MISO did not want to be considered the entity picking and choosing projects between the states. MISO also cannot require the states or RERRAs to participate in a specific way or impose a specific selection process for ERAS projects. Instead, it implemented a project cap, a cycle cap, a strengthened RERRA verification, more detailed application requirements, and strict eligibility requirements to ensure that only truly commercially viable projects will apply to participate in ERAS. MISO is striving to balance the unique differences found in its footprints with some of the characteristics found in other RTO/ISO's proposals.

Due to the very near-term, unexpected load growth that the MISO footprint is experiencing, MISO is proposing a refined process to review and finalize projects that can address these resource adequacy and/or reliability needs. ERAS strikes the right balance between significant competing interests and MISO providing the process to allow generation to come online to address short-term, claimed needs. The Generator Interconnection Queue will remain MISO's priority and focus as ERAS is a unique answer to a temporary and unanticipated problem and is capped both in number of projects and in length of time. Recognizing all the other changes MISO is making to the Generator Interconnection process, MISO fully expects that it will be reduced to one year by the time the ERAS process is designed to sunset. Complex problems commonly require creative solutions and ERAS is MISO's creative solution to the rapid evolution of the energy industry in our footprint.

MISO's refined ERAS proposal, described herein, is just and reasonable. ERAS is balanced in addressing the complex needs identified by numerous parties and is narrowly tailored to the identified resource adequacy and reliability needs. Addressing the looming resource adequacy needs in the MISO footprint requires that MISO and the states work together to provide solutions to the problem. Again, MISO views the ERAS process as simply a tool that states *may*

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[205] *See supra* Section III.B.2.

[206] *PJM Interconnection, L.L.C.*, 190 FERC ¶ 61,084, at P 1 (2025) (RRI Order); *Cal. Indep. Sys. Operator Corp.*, 180 FERC ¶ 61,143.

[207] ERAS Order at P 202.

utilize to address their resource adequacy and/or reliability needs, even the retail choice states. But it also provides a process to ensure that proposed projects are shovel ready and are completed in a short time frame to address the looming resource adequacy and/or reliability needs. Finally, MISO is committed to working with stakeholders to address more generalized queue and industry challenges and ERAS will not change that.

IV. DESCRIPTION OF PROPOSED TARIFF REVISIONS[208]

The proposed Tariff revisions implement the ERAS process and are necessary to distinguish the key differences in how the ERAS process will operate in comparison to MISO's generator interconnection queue. Because the ERAS process is not a queue and is temporary in nature, it is important to clearly identify the differences for clarity and certainty. The instant filing includes ERAS-related revisions in Attachment X (Generator Interconnection Procedures), Attachment X, Appendix 1 (Interconnection Request), and Attachment X, Appendix 6 (Generator Interconnection Agreement).

A. Attachment X, Generator Interconnection Procedures

1. GIP Section 1

Section 1 contains definitions that are used throughout the GIP and its supporting attachments. The proposed new definitions are necessary to implement the ERAS process and to provide clarity and consistency throughout the GIP. In addition to new definitions related to ERAS processes, MISO proposes to revise the definition of "Commitment Projection," "Potential MW Total," and "JTIQ Screening Group, to incorporate MISO ERAS and SPP ERAS into the JTIQ Portfolio and reflect the capacity they will use.[209] "Interconnection Request" was edited to include a request for new generation capacity to be studied under ERAS. This change is necessary to properly document that ERAS projects will be studied separately from MISO's generator interconnection queue and will require a separate election in Appendix 1 to the GIP ("Interconnection Request for a Generating Facility") to be studied as an ERAS project. MISO added additional proposed revisions to include ERAS projects in JTIQ-related definitions to provide clarity that ERAS projects will be considered for JTIQ. MISO also added the definitions

[208] The proposed revisions for each proposal are presented together and in logical order for the purpose of discussion, not in order of importance.

[209] These updates reference both MISO's ERAS and SPP's ERAS projects given that SPP has filed its ERAS process in Commission Docket No. ER25-2296 and both MISO and SPP have filed revisions to update their JOA to reflect these processes in Commission Docket Nos. ER25-2297 and ER25-2298. The revised definitions proposed in this filing align with those filed in Commission Docket Nos. ER25-2297 and ER25-2298. In the event that the Commission accepts MISO' ERAS process but not SPP's, MISO would update the ERAS references in these definitions accordingly.

of Expedited Resource Addition Study (ERAS), Expedited Resource Addition Study Quarterly Study Period, Expedited Generator Interconnection Agreement (EGIA), Local Resource Zone (LRZ), and Relevant Electric Retail Regulatory Authority (RERRA), the latter two of which are defined in Module A.[210]

2. GIP Section 2.1

MISO proposes to add a subsection i to GIP Section 2.1 that governs the application of interconnection procedures.

> i. An Interconnection Request for a new Generating Facility to be studied through the Expedited Resource Addition Study process shall be evaluated pursuant to Section 3.9.2.

This subsection explains that a request for ERAS should be evaluated according to the procedure in GIP Section 3.9.2, which is a new Section MISO proposes to add for the implementation of the ERAS process. This addition is necessary to distinguish the process for evaluating requests for ERAS from other projects entering MISO's generator interconnection queue.

3. GIP Section 3.3.1

MISO proposes to revise Section 3.3.1, which encompasses the procedures for submitting an Interconnection Request. The revisions include clarifying language surrounding the timeline for submitting ERAS Interconnection Requests, where applications will be accepted while the ERAS process is in place, and where the application timeline will be posted to the MISO website. MISO also proposes to increase the Non-Refundable Deposit 1 (D1) to $100,000 for ERAS projects and to require an entry milestone (M2) of $24,000 per Megawatt for new Interconnection Service requested to ensure that ERAS projects are "shovel ready" and to prevent speculative projects from submitting to ERAS. MISO's DPP process contains three phases where three milestone payments are required. The PGIA process requires $8000 per Megawatt for each phase provided upfront, so to facilitate a similar, "one phase" ERAS study, MISO proposes to implement an equivalent milestone payment of $24,000 per Megawatt.

MISO also proposes revising Section 3.3.1 to require an ERAS Interconnection Request to identify the claimed resource adequacy and/or reliability need(s). The revisions include requiring the Interconnection Request to provide information including the location of any load as well as the MW amount of the proposed ERAS project. The revisions also require the ERAS project be located within the same Local Resource Zone, unless the project applicant can demonstrate that the use of a Generating Facility not in the same LRZ was included in a resource filing or other

[210] MISO Tariff, Module A.

submission made to the RERRA. Finally, the revisions limit the amount of Interconnection Service requested by the ERAS project to no more than 150% of the identified MW need. These changes were made to tighten the connection between the verified resource adequacy and/or reliability need with the relevant RERRA.

…

> An Interconnection Request for a Generating Facility requesting processing through the Expedited Resource Addition Study shall identify the claimed resource adequacy and/or reliability need(s) for which it is being submitted. This should include the location (i.e. the county and state, the electrical bus location(s), and the Local Resource Zone) of any load to be served via the off take agreement as well as the peak demand for electricity expected over any one hour period in MWs—the amount of Interconnection Service requested must not exceed 150 percent of the identified MW need. The Generating Facility and the associated resource adequacy and/or reliability need(s) must be within the same Local Resource Zone, unless the resource adequacy and/or reliability need is included in a resource filing made to the RERRA that is providing the verification required in Section 3.9.1.
> …

To further demonstrate that a project is "shovel ready," all documentation, milestone payments, deposits and any necessary data is required at the time of application. These up-front requirements will allow MISO to complete the study process within its estimated 90-day timeframe. Additionally, at the time of application, Interconnection Customers must identify the resource adequacy and/or reliability need for which the project is being submitted. MISO also proposes to require that ERAS projects have a Commercial Operation Date within three calendar years from the submission date of the Interconnection Request. All ERAS projects are eligible to use the grace period of up to three years as documented in GIA Article 2.3.1. MISO's accepted queue reform filing[211] and proposed Order No. 2023 compliance[212] will help MISO facilitate the reduction of the DPP cycle to the approximate one year timeline by 2028, and ERAS projects will help address documented load growth need prior to reducing the DPP cycle timeline.[213]

4. GIP Section 3.4

MISO proposes to add clarifying language stating, "except for projects submitted through the ERAS process as noted in Section 3.9," to this section governing OASIS posting requirements to clarify that MISO intends to publish the list of projects submitted for ERAS on its public

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211 *See* Queue Reform Filing.

212 *Midcontinent Independent System Operator, Inc.*, Compliance Filing for Order Nos. 2023 and 2023-A, Docket No. ER24-2046-000 (May 16, 2024) ("Order 2023 Compliance Filing").

213 *See Midcontinent Indep. Sys. Operator, Inc.*, 178 FERC ¶ 61,141 (2021) ("Timeline Reduction Filing").

website. Although MISO does not publish identifying information for projects submitted to the DPP interconnection queue, MISO believes that ERAS projects require additional transparency for interested parties in the MISO region.

5. GIP Section 3.5

MISO proposes to revise GIP Section 3.5 to add a reference to newly created GIP Section 3.5.2, explained further below, and to clarify that coordination procedures for affected systems apply except as provided by "Sections 3.5.1 and 3.5.2" of the GIP. MISO proposes to revise GIP Section 3.5.1.1 subsection (1) to clarify that ERAS projects shall be included in a JTIQ Screening Group, along with projects in the generator interconnection queue. As discussed in prior stakeholder meetings, MISO intends to consider ERAS projects for JTIQ. This revision is necessary to ensure that ERAS projects are properly included in JTIQ Screening Groups along with projects from MISO's DPP interconnection queue.

MISO proposes to add Section 3.5.2 to incorporate the application of the Affected Systems Coordination Procedures to Interconnection Requests included in ERAS. The revisions will enable MISO to promptly provide any affected systems analysis received from the affected system to the ERAS Interconnection Customer. The revisions also explain that if the affected systems studies and cost information are not available at the time the EGIA is tendered, the EGIA will include an obligation to execute any agreements for the studies. The proposed revisions state that ERAS Interconnection Requests will be submitted to the applicable system study individually and on serial basis. Finally, the revisions require the queue priority date for ERAS projects as the date MISO starts the ERAS System Impact Study unless the controlling agreement between MISO and the affected system provides an alternate queue priority date for ERAS projects. These revisions are needed given that ERAS projects will be studied serially and that existing affected systems coordination rules geared towards multi-phase group studies cannot apply without adjustment. The proposed rule set ensures timely affected systems review using a process appropriate for the accelerated ERAS study process while still allowing needed flexibility for MISO and individual seems partners to make adjustments needed for the specific seam.

6. GIP Sections 3.9 and 3.9.1

MISO proposes to add new GIP Section 3.9 to encompass the necessary processes and implementation details for ERAS Interconnection Requests. Proposed Section 3.9.1 explains the requirements for submitting a project to ERAS, which include the requirements listed in GIP Section 3.3.1, as well as a written verification from a RERRA that states either (1) the new, incremental load addition claimed by the Interconnection Customer is valid and not already included in a plan or other procedure under the RERRA's purview, or (2) addresses a resource adequacy deficiency as determined by the RERRA, state, LSE, or Interconnection Customer and supported by evidence from a state energy forecast, state proceeding, resource plan, response to a request for proposals, or other state or RERRA process.

The revisions to Section 3.9.1.1(iii) also enable retail choice states (Illinois and Michigan) to participate in ERAS. The revisions allow an Interconnection Customer to participate if the new facility addresses a resource adequacy deficiency and will serve retail choice load. If the Interconnection Customer is serving retail choice load, it will not be required to include a verification from a RERRA in accordance with state policy, but MISO will notify the respective RERRA about the request and give that RERRA an opportunity to object to the ERAS application. The Interconnection Customer will also provide evidence of determination of need as described in Section 3.9.1.1(ii). MISO is proposing this language to enable retail choice state participation in ERAS and to reflect how RERRAs operate differently in the retail choice states.

The proposed RERRA language also clarifies that the RERRA verification is not intended to provide evidence of need or suitability of an ERAS project in a separate state or RERRA regulatory process. It is simply a requirement of the MISO ERAS application process that will allow projects to have completed study and be available without prejudicing the ability of the RERRA to make final permitting or certificating decisions according to their laws and regulations.

In the revisions to Section 3.9.1.2, MISO also proposes to require the Interconnection Customer provide an agreement showing that the project submitted to ERAS is intended to be used to meet a claimed resource adequacy and/or reliability need. The agreement may take several forms, as documented in Section 3.9.1, depending on the type of project and associated parties. This language is intended to limit ERAS projects to those needed to meet a resource adequacy and/or reliability need, while also ensuring that certain project types or submitters are not excluded from participating in ERAS.

As previously explained above, the language developed in Section 3.9.1 regarding the RERRA verification and the Interconnection Customer's requirement to provide an executed agreement showing that the project submitted will be used to meet the claimed resource adequacy and/or reliability need were discussed at length with stakeholders and the MISO states before MISO's original ERAS filing and were adjusted to address the Commission's guidance. These proposed revisions are intended to provide sufficient documentation displaying the need to be included in ERAS while also taking into consideration the varied processes of the states in MISO's footprint and the need for the ERAS process to fit within the different regulatory requirements of the MISO states. Because the majority of MISO states are vertically integrated, it is important to consider the states' involvement in resource adequacy as discussed in this letter.

Finally, MISO proposes to add language stating that no changes shall be made to the Interconnection Request after submission. Because the timeline from submission to an executed EGIA is 90 days, this language is necessary to ensure that ERAS projects are studied expeditiously and can be online as soon as possible to meet the stated resource adequacy and/or reliability need.

7. GIP Section 3.9.2

MISO proposes to add GIP Section 3.9.2 to facilitate the evaluation process of projects seeking to use ERAS.

> The Transmission Provider will evaluate Expedited Resource Addition Study requests in the order in which they are submitted using the time stamp from submission. The Transmission Provider will limit the maximum number of the ERAS Interconnection Requests studied in the ERAS process to no more than 68 projects total until the sunset date noted in Section 3.9.9. The Transmission Provider has carved out a maximum of 8 Interconnection Requests of the total 68 Interconnection Requests that may be submitted in accordance with 3.9.1.1(iii) to serve retail choice load and a maximum of 10 Interconnection Requests of the total 68 Interconnection Requests that may be submitted by Independent Power Producers (IPPs) with agreements with entities other than Load Serving Entities to ERAS until the sunset date noted in Section 3.9.9.
>
> The Transmission Provider will limit the maximum size of each ERAS Quarterly Study Period to no more than 10 Interconnection Requests. If more than 10 Interconnection Requests are submitted for one ERAS Quarterly Study Period, those surpassing the limit will be studied in a subsequent ERAS study cycle in the order in which they were submitted. If an ERAS Interconnection Request is within a similar geographical area or impacts the same constraint as another ERAS Interconnection Request within the same ERAS Quarterly Study Period, as defined in the Generator Interconnection Business Process Manuals, then the later submitted request(s) will be studied in a subsequent ERAS study cycle.

The revised language sets out how MISO plans to implement the ERAS project cap. MISO will limit the maximum number of the ERAS Interconnection Requests studied in the ERAS process to no more than 68 projects total until the ERAS sunset date noted in Section 3.9.9. MISO has determined two separate carve outs from the total 68 projects: (1) a maximum of 8 Interconnection Requests that may be submitted to serve retail choice load, and (2) a maximum of 10 Interconnection Requests that may be submitted by Independent Power Producers ("IPP"). The remaining 50 Interconnection Requests may be utilized by other Interconnection Customers in non-retail states.

The proposed language explains that MISO will also cap the number of projects studied in each ERAS study cycle. MISO will limit the maximize size of each ERAS Quarterly Study Period to no more than 10 Interconnection Requests. MISO will complete a screening process on the first 10 Interconnection Requests received per ERAS cycle to determine whether any of the projects are located in the same geographic area or impacting the same constraint. If two or more projects are located in the same geographic area or impact the same constraint as defined by MISO's Generator Interconnection Business Process Manuals, then the first project received as determined

by submission time will remain in the cycle and the other project(s) will be deferred to the next available ERAS cycle.

Other proposed language explains that projects will be evaluated in the order in which they are submitted. It also provides that a project that does not meet the ERAS requirements will be automatically moved to the generator interconnection queue unless the Interconnection Customer informs MISO that it does not want to be processed through the DPP if it fails to qualify for ERAS. Although the project moving from ERAS will be required to meet all requirements of the generator interconnection queue, the automatic transfer to the interconnection queue will prevent projects from having to resubmit an additional Interconnection Request and will provide a more efficient application process. Proposed language also clarifies that if the project is found to be ineligible for ERAS, the project will lose its Non-Refundable Deposit D1. The risk of losing a large deposit if determined to be ineligible for ERAS will encourage parties to only submit projects that they are certain will meet the strict ERAS requirements.

Proposed Section 3.9.2 also documents the process for projects currently in the generator interconnection queue to transfer to ERAS for evaluation. In the situation where a project in the generator interconnection queue is eligible to participate in ERAS and chooses to transfer to the ERAS process, proposed language also clarifies that the project will forfeit its Non-Refundable Deposit D1 and will be subject to withdrawal penalties per Sections 7.6.2.1.1 and 7.8. This proposed addition is necessary to ensure that projects dropping out of the generator interconnection queue do not harm remaining projects in their respective cycles. Similarly, proposed language in Section 3.9.2 limits projects from transferring from the generator interconnection queue to ERAS to only those that have not reached Decision Point II. This language is required to ensure that projects remaining in the generator interconnection queue are not harmed by restudies that occur after projects drop out after Decision Point II. If a project withdraws after Decision Point II, the proposed ERAS revisions will allow it to submit to ERAS after a period of one year from the withdrawal date. This language is necessary to prevent late stage withdrawals from the generator interconnection queue that might harm other projects in the interconnection queue cycle.

8. GIP Section 3.9.3

MISO proposes to add a new GIP Section 3.9.3 to describe the studies that will take place for ERAS projects, which mirror those performed for Interconnection Requests in the DPP seeking NRIS, as described noted in GIP Sections 3.2.1.2 and 3.2.2.2. MISO intends to perform all ERAS studies within 60 Days after kickoff to help ERAS projects quickly obtain an executed EGIA. ERAS projects will be evaluated on a rolling basis during each Quarterly Study Period The studies will be performed serially, based on submission date. serial studies are ideal for ERAS projects since there will be a considerably smaller number of proposed projects spread over a larger geographic area, thus they will not be grouped into clusters which would require late stage restudies.

Proposed language also explains that any Affected System Study results, if available, will be included at the time of the final ERAS study. If the Affected System Study results are unavailable at the time of the final study, those results will be provided separately when received from the applicable Affected System.

9. GIP Section 3.9.4

MISO proposes to add the following Section 3.9.4, which is titled Notice to Proceed to EGIA.

> Interconnection Customer requesting to be included in ERAS shall inform Transmission Provider of its election to proceed within five (5) Calendar Days after receiving the draft results of the Expedited Resource Additions Study. Interconnection Customer that fails to provide an election to proceed within five (5) Calendar Days will result in withdrawal of the Interconnection Request pursuant to Section 3.6 of this GIP. EGIA execution shall occur no later than 30 Calendar Days after receiving Interconnection Customer's election to proceed.

This language is necessary to distinguish between the shorter timeline for ERAS and the general timeline for providing a notice to proceed for a DPP interconnection project. The shortened five Calendar Day timeline is necessary to allow Customers to execute their EGIA within 90 days from kickoff of the Quarterly Study Period.

10. GIP Section 3.9.5

Proposed GIP Section 3.9.5 governs the timeline and necessary requirements regarding tender of the draft pro forma EGIA and JTIQ applicability, and also points to Sections 11.1 through 11.4 of the GIP governing procedures such as MISO's tender of the draft EGIA, negotiations, and execution of the EGIA. This proposed Section provides a five Business Day timeline for MISO to tender a draft *pro forma* EGIA after receiving notification of the Customer's intent to proceed to EGIA.

Due to the varied nature of MISO's and SPP's processes related to JTIQ Service Agreements, proposed revisions provide a path forward for JTIQ eligible ERAS projects if SPP's JTIQ Service Agreement has not been provided to the Interconnection Customer prior to the tender of the draft EGIA. If the SPP JTIQ Service Agreement has not been received at the time of MISO's tender of the EGIA, proposed language requires JTIQ eligible ERAS projects to include a milestone in GIA Appendix B requiring the parties to execute or request the unexecuted filing of an SPP JTIQ Service Agreement within 15 Calendar Days after such agreement has been tendered to the Interconnection Customer. Proposed language also states that ERAS Interconnection Requests included in a JTIQ Participation Group shall adhere to all JTIQ procedures and execute JTIQ Service Agreements as applicable.

11. GIP Sections 3.9.6, 3.9.6.1, 3.9.6.2, and 3.9.6.3

Proposed GIP Section 3.9.6 and its subparts document the process for obtaining refunds of study deposits and milestone payments in the ERAS process.

Proposed GIP Section 3.9.6.1 governs applicable refunds of the Study Deposit (D2). As with generator interconnection requests, ERAS D2 study deposit amounts are based on Megawatt amount of new interconnection service of the ERAS project as stated in GIP Section 3.3.1. The Interconnection Customer will be charged the actual amount of the Expedited Resource Addition Study and will be required to pay any additional costs or will be refunded any overages as applicable.

Proposed GIP Section 3.9.6.2 details the process for receiving a refund of the ERAS milestone payment M2. ERAS projects are eligible to receive a 100% refund of M2 upon withdrawal prior to execution of the EGIA. If an ERAS project withdraws after execution of the EGIA, the project is only eligible to receive a refund of any remaining M2 milestone after meeting the Initial Milestone Payment and/or Network Upgrade costs memorialized in the EGIA.

Should a project withdraw after execution of the EGIA, proposed Section 3.9.6.3 documents the process for providing the initial payment to the Transmission Owner, which will occur within forty-five Calendar Days from the effective date of the EGIA. If the M2 provided by the Interconnection Customer exceeds the initial payment amount, MISO will provide a refund of any remaining M2 within 45 Calendar Days of the effective date of the EGIA. If the Interconnection Customer's M2 is less than the initial payment, the proposed language of 3.9.6.3 requires the Interconnection Customer to provide the remaining portion of the initial payment to the Transmission Owner.

Proposed language in GIP Section 3.9.6.3 also clarifies that Interconnection Customers that withdraw after execution of the EGIA by all parties, or upon the filing of an unexecuted EGIA, will be liable for any Network Upgrade costs documented in the EGIA, including Network Upgrades arising from the Affected System Study process. This language is necessary to ensure that only viable projects that can meet the requirements of ERAS apply to participate in the ERAS process. In the event that a viable project must withdraw after execution of the EGIA, this language is necessary to ensure that no remaining projects are harmed by the withdrawal and Network Upgrades are built as planned.

12. GIP Section 3.9.7

MISO proposes to add new GIP Section 3.9.7, which is titled Transfer of Ownership of Expedited Resource Addition Study Request.

> An Interconnection Customer participating in the Expedited Resource Addition Study may transfer its Interconnection Request to another entity only after execution of the EGIA or filing the EGIA unexecuted. The new entity must maintain the eligibility requirements per Sections 3.3.1 and 3.9.1.

This language is necessary to prevent transfers prior to EGIA execution that might slow down the timeline for studying an ERAS project and ultimately delay the ability for MISO to move ERAS projects to EGIA execution within 90 days from kickoff. Prohibiting any changes to an ERAS project prior to EGIA execution will allow MISO to maintain its proposed ERAS timeline while allowing projects the flexibility to transfer the project to a new owner after EGIA execution. Similar to requirements for the generator interconnection queue, any transferee must maintain the applicable requirements to remain a valid ERAS project after EGIA execution.

13. GIP Section 3.9.8

MISO proposes to add new GIP Section 3.9.8, titled Modifications of Expedited Resource Addition Study Request.

> After entering the Expedited Resource Addition Study as defined in Section 3.9.3, no changes to the In-Service Date or Commercial Operation Date of the Generating Facility is permitted via Section 4.4.4. An ERAS Interconnection Request that is deferred to the next available ERAS Quarterly Study Period will be allowed to extend its In-Service Date or Commercial Operation Date to be no more than three calendar years from the kickoff of the ERAS Quarterly Study Period in which its application is studied. At the completion of the Expedited Resource Addition Study, the Commercial Operation Date and In-Service Date shall be set forth in the EGIA.

This language is necessary to ensure that ERAS projects are able to meet the resource adequacy and/or reliability need within the timeframe allotted by ERAS. The proposed ERAS COD requirements set forth in GIP Section 3.3.1 are specifically for generation needed to meet load intended to come online while ERAS is in place. Disallowing changes to the In-Service Date or COD after entering ERAS creates the certainty necessary to ensure that these projects will meet the need identified in the Interconnection Request and will prevent projects with uncertain timelines from entering ERAS.

14. GIP Section 3.9.9

MISO proposes to add new GIP Section 3.9.9, titled Sunset of Expedited Resource Addition Study Process.

> Following the effective date of the Tariff revisions accepted in Commission Docket No. ER25-____, the Transmission Provider will terminate the ERAS process at the earlier of the completion of sixty-eight ERAS Interconnection Request studies or August 31, 2027. In the event the Transmission Provider determines the sunset date should be extended, the Transmission Provider shall submit an additional filing to the Commission pursuant to Section 205 of the Federal Power Act seeking such later sunset date. Upon termination of ERAS, the Transmission Provider will no longer accept new ERAS Interconnection Requests. Any ERAS Interconnection Requests accepted but cannot be studied due to the sunset of the ERAS process will automatically move to the standard Definitive Planning Phase queue unless the customer chooses to withdraw. If deemed ineligible for the ERAS process, the project will forfeit its Non-Refundable Deposit D1.

This language is necessary to provide certainty that ERAS is a temporary process and that MISO intends to use ERAS for a limited period of time to meet generation shortages due to reasons explained above. ERAS will automatically sunset at the earlier of the completion of 68 ERAS Interconnection Request studies or August 31, 2027. The ERAS process is intended to fill the gap created by current queue backlogs and projects with GIAs yet to come online by providing expedited treatment for needed projects to be studied and come online quickly. As previously stated, the ERAS process is intended to be temporary and to fulfill the purpose of meeting generation needs during the short time period prior to the ERAS sunset date. MISO does not intend to request additional time for ERAS, but should MISO determine that additional time is needed to process ERAS projects to fill the aforementioned gap, MISO will submit an additional 205 filing and will justify the need for additional time.

15. GIP Section 5.13

MISO proposes to add new GIP Section 5.13, titled Transition to ERAS Process.

> All requests for the Expedited Resource Addition Study that are submitted to the Transmission Provider after August 6, 2025 will be subject to the revised Tariff requirements accepted in Docket No. ER25-___.

MISO proposes to begin the first ERAS Quarterly Study Period on September 2, 2025, which will be the first Quarterly Study Period after the effective date of these revisions, August 6, 2025.

16. GIP Section 7.2.1

MISO proposes to revise GIP Section 7.2.1, subpart (ii) to add the following language:

> Reasonable evidence of Site Control for one hundred percent (100%) of the mileage of the Generating Facility's Interconnection Facilities for the Expedited Resource Addition Study request must be received at the time the application is submitted. The financial security in lieu of Site Control for the Generating Facility's Interconnection Facilities will not be accepted for an Expedited Resource Addition Study request.

Increased Site Control requirements for the Generating Facility's Interconnection Facilities (in conjunction with the accepted increased Site Control requirements under 7.2.1[214]) will ensure that projects submitted to ERAS are "shovel ready" and able to quickly meet the needs of the load they seek to service. Current interconnection queue Site Control requirements only require 50% Site Control of the Interconnection Customer's Interconnection Facilities at the time of submission, so this increased Site Control requirement will encourage only ready projects to submit to the ERAS process. Similarly, disallowing financial security in lieu of Site Control will prohibit any projects from being eligible for ERAS if it is unable to obtain the proper permits or siting requirements. Both updates to Site Control requirements will ensure that only "shovel ready" projects apply and will allow ERAS projects to quickly move to EGIA execution.

17. GIP Section 7.3.1.4

MISO proposes to add a reference to ERAS projects in Section 7.3.1.4 to clarify that projects from the DPP and ERAS will be notified if included in a JTIQ Screening Group. Although not part of the DPP, ERAS projects may impact a JTIQ Upgrade and should be subject to the same rules as DPP projects with respect to JTIQ. ERAS projects will be eligible for inclusion in the JTIQ Screening Group, Participation Group, and Commitment Groups based on the same criteria

[214] *See* Queue Reform Filing at 10.

that are applied to DPP projects. This revision is necessary to ensure that ERAS projects are included in the JTIQ construct and do not get a free ride.[215]

18. GIP Section 7.3.2.3.1

MISO proposes to add "including ERAS projects not otherwise subject to Transmission Provider's three-phase DPP" in subpart 1, to clarify that ERAS projects that are part of a JTIQ Screening Group will be subject to additional Affected System analysis, as well as analysis required in Section 7.3.2.3 of the GIP. The additional analysis determines the impact of an ERAS project on the SPP system through Expanded Scope Analysis and Supplemental Affected System Analysis as documented in subparts a and b of this section and the inclusion of the aforementioned edits ensures that applicable ERAS projects will be studied similarly to DPP projects in these instances.

19. GIP Section 11.1

MISO proposes to revise Section 11.1 to include the distinction that ERAS projects will not contain restudies and that tender of the draft EGIA will occur after the Interconnection Facilities Study initiated through ERAS. MISO also proposes to revise this Section to clarify that ERAS Interconnection Requests tender of the EGIA will occur on a different timeline than DPP projects, which timeline for tender is memorialized in new GIP Section 3.9.5. These edits are necessary to properly document the shortened timeline for tender of ERAS projects and the differences in timing between ERAS projects with one study and DPP projects with multiple studies.

20. GIP Section 11.2 and 11.2.1

MISO proposes to revise Section 11.2 to clarify that ERAS projects will have a shorter, 5 Business Day timeline to return comments on the draft EGIA. MISO also proposes to revise this Section to clarify that MISO shall tender a revised draft EGIA after 5 Business Days of receiving the comments. For ERAS projects, negotiations of EGIAS shall be no more than 20 Business Days from the notice to proceed in Section 3.9.4. Revisions to 11.2.1 clarify that ERAS projects are unable to postpone the start of the EGIA negotiation period.

These edits are needed to shorten the negotiations timeframe to keep the ERAS process to approximately 90 days from kickoff to EGIA execution. This shortened timeframe will ensure that ERAS projects are able to execute the EGIA quickly and come online within the timeframe allotted to serve the project's identified need.

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[215] MISO notes that it will be necessary to update some language in its Joint Operating Agreement with the Southwest Power Pool, Tariff Rate Schedule 6 ("SPP JOA"), which, for MISO, discussed JTIQ only in terms of DPP projects. This language reflects the fact that ERAS did not exist at the time. MISO has discussed updating the JOA with SPP and plans to make a joint filing to properly references ERAS before the requested effective date for this filing.

21. GIP Section 11.3

MISO proposes to revise Section 11.3 to provide that for ERAS projects the Transmission Provider shall provide the Interconnection Customer and Transmission Owner a final EGIA within 10 Business Days after completion of the negotiation period in accordance with Section 11.2. These revisions also provide that the parties must execute the EGIA or request to file unexecuted within 10 Business Days of tender of the final EGIA, otherwise the project will be deemed to have withdrawn its Interconnection Request. These revisions are required to properly document the shorter timeline for ERAS projects as compared to the timeline for DPP GIA execution as memorialized in this Section.

B. Attachment X, Appendix 6, Generator Interconnection Agreement

a. Article 1 Definitions

MISO proposes to revise Article 1 to include ERAS-related definitions consistent with the GIP, as applicable, and to provide updates to JTIQ-related definitions to clarify that MISO ERAS and SPP ERAS projects will be included in JTIQ, also as provided in the GIP.

b. Article 2.3.3

MISO proposes to revise Article 2.3.3 to state that ERAS projects must provide all security required in Section 2.4 prior to any termination request for an ERAS project becoming effective. This language is necessary to ensure that projects are held liable for any Network Upgrades that would be memorialized in an EGIA or related agreement and to prevent harm to other projects due to the withdrawal.

c. Article 2.4

MISO proposes to revise Article 2.4 to specify that should an ERAS project terminate, it will be liable for any Network Upgrade costs identified in the EGIA or that would be memorialized in an FCA, MPFCA, or JTIQ Service Agreement. If the final costs have not been determined, the Customer must provide security according to the most recent estimate. Additionally, the Transmission Provider will provide any applicable refunds of payments or security within 90 Calendar Days of providing the final invoice of NUs to the Customer. As stated above, the proposed language is necessary to ensure that only "shovel ready" projects submit to ERAS, knowing those projects will assume the risk of paying for any Network Upgrades identified in an EGIA or that would be memorialized in an FCA, MPFCA, or JTIQ Service Agreement. This language will ensure that no other projects are affected by the termination.

d. Appendix B Milestones

MISO proposes to add new milestone 1f to the *pro forma* Generator Interconnection Agreement:

1f.	Enter into any agreement required by an Affected System for the study, construction, or funding of a network upgrade to mitigate impacts (for Interconnection Requests processed through ERAS) pursuant to GIP Section 3.5.2.	Within 15 Calendar Days after tender.

This revision is needed to ensure that ERAS interconnection requests are subject to the same obligations as other Interconnection Requests with respect to network upgrades identified by affected systems. The requirement to execute an agreement with the affected system to mitigate any impacts from the ERAS Interconnection Request within 15 days after agreement tender is included in proposed GIP Section 3.5.2. It is appropriate to reflect this commitment in a GIA milestone given that, due to the accelerated timing of ERASs, an affected system may first be able to tender their form of agreement after the ERAS Interconnection Customer already has executed their GIA. Including milestone 1f in Appendix B ensures that this obligation remains enforceable even after the customer has an effective GIA. This puts ERAS Interconnection Customers on the same footing as DPP Interconnection Customers.

C. Attachment X, Appendix 1, Interconnection Request for a Generating Facility

MISO proposes to revise Attachment X, Appendix 1 to add a check box in Section 2 indicating that the interconnection Request is being submitted as an ERAS project.

MISO also proposes to add subpart s to Section 4, stating that at the time of application to ERAS, the Interconnection Customer must provide information about the resource adequacy and/or reliability need that the ERAS project is intended to address. These proposed revisions are needed to properly memorialize the requirements to be included in ERAS, which includes the Interconnection Customer identifying resource adequacy and/or reliability need the project claims to meet. The ERAS process is intended to facilitate matching generation with load within the next few years, so requiring a specific need will prevent projects from submitting to ERAS simply to circumvent the generator interconnection queue process. This proposed language will ensure that ERAS projects are limited to those that truly identify a claimed resource adequacy and/or reliability need.

V. DOCUMENTS SUBMITTED WITH THIS FILING

In addition to this Transmittal Letter, the documents submitted with this filing are:

Tab A – Redlined Tariff Sheets[216];

Tab B – Clean Tariff Sheets; and

Tab C – Prepared Direct Testimony of Andrew Witmeier

VI. PROPOSED EFFECTIVE DATE, AND REQUEST FOR EXPEDITED ACTION AND SHORTENED COMMENT PERIOD

MISO requests that the proposed Tariff revisions be made effective on August 6, 2025. To give certainty to stakeholders and allow them time to prepare Interconnection Requests in advance of the first ERAS deadline, MISO respectfully requests the Commission issue an order on an expedited basis by July 22, 2025. MISO needs to address the looming resource adequacy and reliability needs identified in this filing as expeditiously as possible and stakeholders will need to know if the process has been accepted sufficiently in advance of the deadline to plan their projects. Thus, MISO can accommodate the ordinary 60 day timeframe for revisions becoming effective and need not seek waiver for a shortened effective date provided that an order is issued within 45 days. The original ERAS proposal was discussed extensively with stakeholders and the main refinements made to that proposal were addressed in the May PAC Meeting and tailored to the Commission's guidance issued on May 16, 2025.

To enable the Commission's consideration of this filing, MISO also requests that the Commission establish a ten (10) day comment period for this filing – June 16, 2025. As noted above, this filing represents a refinement to MISO's original ERAS proposal and all affected parties have had ample notice of that filing and the Commission's guidance responded to in this submission. This effective date will ensure that the proposed changes can be implemented in advance of the September 2, 2025 ERAS Quarterly Study Period start date.

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[216] Language currently pending before the Commission in the following, unrelated docket is highlighted in yellow: Docket No. ER25-2417-000. MISO requests that the Commission treat such highlighted language as subject to the outcome of the pending proceeding. MISO commits to file any revisions to this highlighted language as necessary to comply with any Commission order in the proceeding. MISO has removed language that has a future effective date of June 1, 2029 and is pending under Docket No. ER22-1640-006. In addition, MISO has removed pending language filed in Docket No. ER24-2046-000, and any changes will be based on the outcome of that docket. If needed, MISO commits to make a subsequent filing with the Commission to reflect the most up-to-date version of the then-current Tariff provisions prior to the effective dates of the language in Docket Nos. ER22-1640-006 and ER24-2046-000.

MISO submits that the requirements of Section 35.13 of the Commission's regulations, 18 C.F.R. § 35.13 (2024), that have not been specifically addressed herein are inapplicable to this filing. To the extent that the Commission determines any of these sections to be applicable to this filing, MISO respectfully requests waiver of the requirements of such sections.

VII. COMMUNICATIONS, NOTICE, AND SERVICE

Correspondence and communication with respect to this filing should be sent to the following individuals, which MISO requests to also be included on the official service list:

Sarah Nieman*
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*Persons authorized to receive service

MISO notes that it has served a copy of this filing electronically, including attachments, upon all Tariff Customers under the Tariff, MISO Members, Member representatives of Transmission Owners and Non-Transmission Owners, as well as all state commissions within the Region. The filing has been posted electronically on MISO's website at https://www.misoenergy.org/legal/ferc-filings/ for other interested parties in this matter. In addition, MISO has served a copy of this filing electronically on all parties to this agreement.

IX. CONCLUSION

MISO's proposed ERAS reforms are just and reasonable, are not unduly discriminatory or preferential, and thus satisfy the requirements of FPA section 205(a). For all of the foregoing reasons, MISO respectfully requests that the Commission: (1) accept this filing with the August 6, 2025 effective date; (2) issue an order by July 22, 2025, and (3) grant waiver of any Commission regulations that the Commission may deem applicable to this filing.

Respectfully submitted,

/s/ Sarah Nieman

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Attachments