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. 202-26-46
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	)))))	Order No. 202-26-47

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

Exhibit 1
December Schahfer Order

Department of Energy
Washington, DC 20585

Order No. 202-25-12

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

BACKGROUND

The R.M. Schahfer Generating Station (Schahfer) is an electric generating facility in Wheatfield, Indiana. Schahfer is owned and operated by Northern Indiana Public Service Company (NIPSCO), a division of NiSource Inc. Schahfer consists of two 129 MW natural-gas fired units and two coal-fired units, Unit 17 (423.5 MW) and Unit 18 (423.5 MW).[3] Unit 17 and Unit 18 began operations in 1983 and 1986 respectively. Unit 17 and Unit 18 are both slated to cease operations in December 2025.[4]

EMERGENCY SITUATION

Midcontinent Independent System Operator, Inc.'s (MISO) year-round resource adequacy concerns are well documented. In 2022, MISO requested Federal Energy Regulatory Commission (FERC) approval of its filing to revise its resource adequacy construct (including the Planning Resource Auction or PRA) to establish capacity requirements for each of the four seasons of the year rather than on an annual basis determined by peak summer demand.[5] MISO justified this revision by explaining that "Reliability risks associated with Resource Adequacy have shifted from 'Summer only' to a year-round concern."[6] MISO noted that over 60% of all

[1] 16 U.S.C. § 824a(c).
[2] 42 U.S.C. § 7151(b).
[3] U.S. Energy Information Administration, Form EIA-860, Schedule 3: Generator Data (2024), https://www.eia.gov/electricity/data/eia860/.
[4] As coal-fired facilities, it would be difficult for the Schahfer Units 17 and 18 to resume operations once they have been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30-60 days to repair if a unit comes offline. In addition, other practical issues, such as employment, contracts, and permits may greatly increase the timeline for resumption of operations. Further, if Schahfer were to begin disassembling the plant or other related facilities, the associated challenges would be greatly exacerbated. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist.
[5] *Midcontinent Independent System Operator, Inc.,* FERC Docket No. ER22-495-000 (Nov. 30, 2021). This request was approved by FERC on August 31, 2022. *See Midcontinent Independent System Operator, Inc.*, 180 FERC ¶ 61,141 (2022).
[6] MISO Transmittal Letter at 3, FERC Docket No. ER22-495-000 (Nov. 30, 2021).

"MaxGen" events (events when MISO initiates emergency procedures because of concerns over the adequacy of available generation) occurred outside of the summer season.[7]

In December of 2023, MISO released an "Attributes Roadmap," in which it presented "an in-depth look at the challenges of operating a reliable bulk electric system in a rapidly transforming energy landscape."[8] Among other things, this report described changes in the time of year during which the risk of the loss of load was greatest. For the 2023/24 Planning Year, the greatest risk of loss of load was in the summer, but it is expected that by the summer of 2027, there will be an equal loss of load risk in both the summer and fall seasons. MISO also projected that the risk of loss of load in the winter and spring seasons, although not as high as in the summer or fall, will nevertheless increase over time.[9]

More recently, MISO affirmed the resource adequacy problems occurring outside of its summer season in its 2024 report entitled, "*MISO's Response to the Reliability Imperative."*[10] In a section of that report entitled "Risks in Non-Summer Seasons," MISO again stressed that it has resource reliability concerns outside of the summer season:

> Widespread retirements of dispatchable resources, lower reserve margins, more frequent and severe weather events and increased reliance on weather-dependent renewables and emergency-only resources have altered the region's historic risk profile, creating risks in non-summer months that rarely posed challenges in the past.[11]

These MISO studies indicate that the emergency conditions caused by the loss of generation capacity in MISO extend past the summer season. The evidence indicates that there is also a potential longer term resource adequacy emergency in MISO.

In its 2024 Long-Term Reliability Assessment (LTRA), the North American Electric Reliability Corporation (NERC) notes that the MISO assessment area is at an elevated risk "because probabilistic assessments indicate above-normal generator outages during extreme weather can result in unserved energy or load loss. With uncertainty around new resource additions and existing generator retirements, MISO is also at risk of falling below [Reference Margin Levels] within the next five years."[12]

When MISO reported the results of its PRA for the 2025-26 Planning Year, it noted that "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources" in the northern and central zones, which include Indiana.[13]

---

[7] *Id.* at 3-4.
[8] MISO, *Attributes Roadmap*, at 3 (Dec. 2023), https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf.
[9] *Id.* at 11.
[10] MISO, *MISO's Response to the Reliability Imperative* (Updated February 2024), https://cdn misoenergy.org/2024+Reliability+Imperative+report+Feb.+21+Final504018.pdf.
[11] *Id.* at 12.
[12] *NERC 2024 Long-Term Reliability Assessment*, at 13 (December 2024, corrected July 11, 2025), https://www.nerc.com/globalassets/our-work/assessments/2024-ltra_corrected_july_2025.pdf.
[13] MISO, *Planning Resource Auction: Results for Planning Year 2025-26*, at 13 (April 2025), https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf.

On June 6, 2025, the Organization of MISO States (OMS) and MISO issued the results of their survey, which has been conducted annually for many years to determine the degree to which expected capacity resources satisfy planning reserve margin requirements.[14] The 2025 Survey presented projections of resource adequacy for the summer of 2026 and subsequent years. Although the survey projected a potential capacity surplus for the summer of 2026, it also projected that at least 3.1 GW of additional generation capacity beyond currently committed generation capacity must be added to meet the projected planning reserve margin.[15] The survey also projected that there would be insufficient capacity to meet the peak demand for electricity in each of the following four summers, increasing from a deficit of 1.4 GW in 2027 to 8.2 GW in 2030.[16] Similar results were projected for MISO's winter seasons, with a small surplus of generation capacity in 2026, followed by increasing deficits the following four years.[17]

The primary reasons for these projected deficits also are shown on the OMS-MISO survey. Large quantities of existing generation capacity are projected to be retired each year while, at the same time, the demand for electricity is projected to increase at an accelerating pace.[18] Although the OMS-MISO survey projects generation capacity to continue to increase in the coming years with the addition of new potential generation assets, the increase in capacity is largely offset by the projected retirements, and does not keep up with the growth in demand.[19]

MISO has been taking steps to address these projected deficits, but the solution is years away. For example, on June 6, 2025, MISO submitted a proposal to FERC to establish an Expedited Resource Addition Study (ERAS) process to provide a framework for the expedited study of interconnection requests to address urgent resource adequacy and reliability needs in the near term. This proposal was approved by FERC on July 21, 2025.[20] The ERAS process should help expedite the construction of needed new capacity. However, resources studied under the ERAS will have commercial operation dates that are at least three years away, and are provided an additional three-year grace period to commence commercial operations.[21] In addition, supply chain constraints impeding the acquisition of critical grid components, including large natural gas turbines and transformers, are likely to further hinder rapid construction and exacerbate reliability concerns.[22] Consequently, it is not at all clear that the new ERAS process will result in the addition of new capacity in the next few years.

More broadly, executive orders issued by President Donald J. Trump on January 20, 2025 and April 8, 2025, underscored the dire energy challenges facing the Nation due to growing

---

[14] OMS and MISO, *OMS-MISO Survey Results* (Updated June 6, 2025), https://cdn misoenergy.org/20250606%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation702311.pdf.

[15] *Id.* at 2.

[16] *Id.* at 7.

[17] *Id.* at 9.

[18] *Id.* at 7, 9.

[19] *Id*.

[20] *Midcontinent Independent System Operator, Inc.*, 192 FERC ¶ 61,064 (2025).

[21] *Id.* P 84.

[22] *See generally*, S&P Global, *US Gas-Fired Turbine Wait Times as Much as Seven Years; Costs Up Sharply* (May 2025), ("With demand for natural gas-fired turbines in the US rapidly accelerating amid power demand growth forecasts driven by AI, manufacturing, and electrification, wait times for turbines are anywhere between one and seven years depending on the model, and costs have increased considerably, experts told Platts."), https://www.spglobal.com/commodity-insights/en/news-research/latest-news/electric-power/052025-us-gas-fired-turbine-wait-times-as-much-as-seven-years-costs-up-sharply.

resource adequacy concerns. President Trump declared a national energy emergency in Executive Order 14156, "Declaring a National Energy Emergency," in which he determined that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy."[23] The Executive Order adds: "Hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets."[24] In a subsequent Executive Order 14262, "Strengthening the Reliability and Security of the United States Electric Grid," President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing."[25]

Further, the Department detailed the myriad challenges affecting the Nation's energy systems in its July 2025 "Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid," issued pursuant to the President's directive in Executive Order 14262. The Department concluded that "[a]bsent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation."[26]

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of Energy determines "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy," then the Secretary has the authority "to require by order . . . such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest."[27] This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of Schahfer Units 17 and 18 when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

Such is the case here. As described above, the emergency conditions resulting from increasing demand and shortage from accelerated retirement of generation facilities will continue in the near term and are also likely to continue in subsequent years. This could lead to the loss of power to homes and businesses in the areas that may be affected by curtailments or power outages, presenting a risk to public health and safety. Given the responsibility of MISO to

[23] Executive Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (*Declaring a National Energy Emergency*), https://www federalregister.gov/documents/2025/01/29/2025-02003/declaring-a-national-energy-emergency.
[24] *Id*.
[25] Executive Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (*Strengthening the Reliability and Security of the United States Electric Grid*), https://www federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid.
[26] U.S. Department of Energy, *Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid*, at 1 (July 2025), https://www.energy.gov/sites/default/files/2025.07/DOE%20Final%20EO%20Report%20%28FINAL%20JULY%207%29.pdf.
[27] Although the text of FPA section 202(c) grants this authority to "the Commission," section 301(b) of the Department of Energy Organization Act transferred this authority to the Secretary of Energy. *See* 42 U.S.C. § 7151(b).

identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, continued additional dispatch of Schahfer Units 17 and 18 is necessary to best meet the emergency arising from increased demand, determined shortage, and other causes, and serve the public interest under FPA section 202(c).

To ensure Schahfer Units 17 and 18 will be available if needed to address emergency conditions, Schahfer Units 17 and 18 shall remain in operation until March 23, 2026.

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

A. From December 23, 2025, MISO and NIPSCO, shall take all measures necessary to ensure that Schahfer Units 17 and 18 are available to operate. For the duration of this Order, MISO is directed to take every step to employ economic dispatch of Schahfer Units 17 and 18 to minimize cost to ratepayers. Following the conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. NIPSCO is directed to comply with all orders from MISO related to the availability and dispatch of the Schahfer Units 17 and 18.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters as determined by MISO, pursuant to paragraph A. MISO shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether Schahfer Units 17 and 18 has operated in compliance with the allowances contained in this Order.

C. All operation of Schahfer Units 17 and 18 must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.

D. By January 13, 2026, MISO is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of Schahfer Units 17 and 18 consistent with this Order. MISO and NIPSCO shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.

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

F. This Order shall not preclude the need for Schahfer Units 17 and 18 to comply with applicable state, local, or Federal law or regulations following the expiration of this Order.

G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, Schahfer Units 17 and 18 shall not be considered capacity resources.

H. This Order shall be effective from 11:59 PM Eastern Standard Time (EST) on December 23, 2025, and shall expire at 11:59 PM Eastern Daylight Time (EDT) on March 23, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Denver, Colorado at 6:39 PM EST on this 23rd day of December 2025.

Chris Wright
Secretary of Energy

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

Indiana Utility Regulatory Commission
Chairman Jim Huston
Commissioner David Veleta
Commissioner David Ziegner

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. 202-26-46
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	)))))	Order No. 202-26-47

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

Exhibit 2
December Culley Order

Department of Energy
Washington, DC 20585

Order No. 202-25-13

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

BACKGROUND

The F.B. Culley Generating Station (Culley) is an electric generating facility in Warrick County, Indiana. Culley is owned and operated by CenterPoint Energy and consists of two coal-fired generation units, Unit 2 (103.7 MW) and Unit 3 (265.2 MW), with a combined name plate capacity of 368.9 MW. Unit 2 and Unit 3 began operations in 1966 and 1973, respectively. Unit 2 is slated to cease operations in December 2025.[3]

EMERGENCY SITUATION

Midcontinent Independent System Operator, Inc.'s (MISO) year-round resource adequacy concerns are well documented. In 2022, MISO requested Federal Energy Regulatory Commission (FERC) approval of its filing to revise its resource adequacy construct (including the Planning Resource Auction or PRA) to establish capacity requirements for each of the four seasons of the year rather than on an annual basis determined by peak summer demand.[4] MISO justified this revision by explaining that "Reliability risks associated with Resource Adequacy have shifted from 'Summer only' to a year-round concern."[5] MISO noted that over 60% of all "MaxGen" events (events when MISO initiates emergency procedures because of concerns over the adequacy of available generation) occurred outside of the summer season.[6]

In December of 2023, MISO released an "Attributes Roadmap," in which it presented "an in-depth look at the challenges of operating a reliable bulk electric system in a rapidly

[1] 16 U.S.C. § 824a(c).
[2] 42 U.S.C. § 7151(b).
[3] As a coal-fired facility, it would be difficult for Culley Unit 2 to resume operations once it has been retired. Specifically, any stop and start of operation creates heating and cooling cycles that could cause an immediate failure that could take 30-60 days to repair if a unit comes offline. In addition, other practical issues, such as employment, contracts, and permits may greatly increase the timeline for resumption of operations. Further, if Culley were to begin disassembling the plant or other related facilities, the associated challenges would be greatly exacerbated. Thus, continuous operation is required in such cases so long as the Secretary determines a shortage exists and is likely to persist.
[4] *Midcontinent Independent System Operator, Inc.,* FERC Docket No. ER22-495-000 (Nov. 30, 2021). This request was approved by FERC on August 31, 2022. *See Midcontinent Independent System Operator, Inc.*, 180 FERC ¶ 61,141 (2022).
[5] MISO Transmittal Letter at 3, FERC Docket No. ER22-495-000 (Nov. 30, 2021).
[6] *Id.* at 3-4.

transforming energy landscape."[7] Among other things, this report described changes in the time of year during which the risk of the loss of load was greatest. For the 2023/24 Planning Year, the greatest risk of loss of load was in the summer, but it is expected that by the summer of 2027, there will be an equal loss of load risk in both the summer and fall seasons. MISO also projected that the risk of loss of load in the winter and spring seasons, although not as high as in the summer or fall, will nevertheless increase over time.[8]

More recently, MISO affirmed the resource adequacy problems occurring outside of its summer season in its 2024 report entitled, "*MISO's Response to the Reliability Imperative."*[9] In a section of that report entitled "Risks in Non-Summer Seasons," MISO again stressed that it has resource reliability concerns outside of the summer season:

> Widespread retirements of dispatchable resources, lower reserve margins, more frequent and severe weather events and increased reliance on weather-dependent renewables and emergency-only resources have altered the region's highest historic risk profile, creating risks in non-summer months that rarely posed challenges in the past.[10]

These MISO studies indicate that the emergency conditions caused by the loss of generation capacity in MISO extend past the summer season. The evidence indicates that there is also a potential longer term resource adequacy emergency in MISO.

In its 2024 Long-Term Reliability Assessment (LTRA), the North American Electric Reliability Corporation (NERC) notes that the MISO assessment area is at an elevated risk "because probabilistic assessments indicate above-normal generator outages during extreme weather can result in unserved energy or load loss. With uncertainty around new resource additions and existing generator retirements, MISO is also at risk of falling below [Reference Margin Levels] within the next five years."[11]

When MISO reported the results of its PRA for the 2025-26 Planning Year, it noted that "new capacity additions were insufficient to offset the negative impacts of decreased accreditation, suspensions/retirements and external resources" in the northern and central zones, which include Indiana.[12]

On June 6, 2025, the Organization of MISO States (OMS) and MISO issued the results of their survey, which has been conducted annually for many years to determine the degree to

---

[7] MISO, *Attributes Roadmap*, at 3 (Dec. 2023), https://cdn.misoenergy.org/2023%20Attributes%20Roadmap631174.pdf.
[8] *Id.* at 11.
[9] MISO, *MISO's Response to the Reliability Imperative* (Updated Feb. 2024), https://cdn misoenergy.org/2024+Reliability+Imperative+report+Feb.+21+Final504018.pdf.
[10] *Id.* at 12.
[11] *NERC 2024 Long-Term Reliability Assessment*, at 13 (December 2024, corrected July 11, 2025), https://www.nerc.com/globalassets/our-work/assessments/2024-ltra_corrected_july_2025.pdf.
[12] MISO, *Planning Resource Auction: Results for Planning Year 2025-26*, at 13 (April 2025), https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf.

which expected capacity resources satisfy planning reserve margin requirements.[13] The 2025 Survey presented projections of resource adequacy for the summer of 2026 and subsequent years. Although the survey projected a potential capacity surplus for the summer of 2026, it also projected that at least 3.1 GW of additional generation capacity beyond currently committed generation capacity must be added to meet the projected planning reserve margin.[14] The survey also projected that there would be insufficient capacity to meet the peak demand for electricity in each of the following four summers, increasing from a deficit of 1.4 GW in 2027 to 8.2 GW in 2030.[15] Similar results were projected for MISO's winter seasons, with a small surplus of generation capacity in 2026, followed by increasing deficits the following four years.[16]

The primary reasons for these projected deficits also are shown on the OMS-MISO survey. Large quantities of existing generation capacity are projected to be retired each year while, at the same time, the demand for electricity is projected to increase at an accelerating pace.[17] Although the OMS-MISO survey projects generation capacity to continue to increase in the coming years with the addition of new potential generation assets, the increase in capacity is largely offset by the projected retirements, and does not keep up with the growth in demand.[18]

MISO has been taking steps to address these projected deficits, but the solution is years away. For example, on June 6, 2025, MISO submitted a proposal to FERC to establish an Expedited Resource Addition Study (ERAS) process to provide a framework for the expedited study of interconnection requests to address urgent resource adequacy and reliability needs in the near term. This proposal was approved by FERC on July 21, 2025.[19] The ERAS process should help expedite the construction of needed new capacity. However, resources studied under the ERAS will have commercial operation dates that are at least three years away, and are provided an additional three-year grace period to commence commercial operations.[20] In addition, supply chain constraints impeding the acquisition of critical grid components, including large natural gas turbines and transformers, are likely to further hinder rapid construction and exacerbate reliability concerns.[21] Consequently, it is not at all clear that the new ERAS process will result in the addition of new capacity in the next few years.

---

[13] OMS and MISO, *OMS-MISO Survey Results* (Updated June 6, 2025), https://cdn misoenergy.org/20250606%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation702311.pdf.

[14] *Id.* at 2.

[15] *Id.* at 7.

[16] *Id.* at 9.

[17] *Id.* at 7, 9.

[18] *Id.*

[19] *Midcontinent Independent System Operator, Inc.,* 192 FERC ¶ 61,064 (2025).

[20] *Id.* P 84.

[21] *See generally*, S&P Global, *US Gas-Fired Turbine Wait Times as Much as Seven Years; Costs Up Sharply*, (May 2025), ("With demand for natural gas-fired turbines in the US rapidly accelerating amid power demand growth forecasts driven by AI, manufacturing, and electrification, wait times for turbines are anywhere between one and seven years depending on the model, and costs have increased considerably, experts told Platts."), https://www.spglobal.com/commodity-insights/en/news-research/latest-news/electric-power/052025-us-gas-fired-turbine-wait-times-as-much-as-seven-years-costs-up-sharply.

More broadly, executive orders issued by President Donald J. Trump on January 20, 2025, and April 8, 2025, underscore the dire energy challenges facing the Nation due to growing resource adequacy concerns. President Trump likewise declared a national energy emergency in Executive Order 14156, "Declaring a National Energy Emergency," that the "United States' insufficient energy production, transportation, refining, and generation constitutes an unusual and extraordinary threat to our Nation's economy, national security, and foreign policy."[22] The Executive Order adds: "Hostile state and non-state foreign actors have targeted our domestic energy infrastructure, weaponized our reliance on foreign energy, and abused their ability to cause dramatic swings within international commodity markets."[23] In a subsequent Executive Order 14262, "Strengthening the Reliability and Security of the United States Electric Grid," President Trump emphasized that "the United States is experiencing an unprecedented surge in electricity demand driven by rapid technological advancements, including the expansion of artificial intelligence data centers and increase in domestic manufacturing."[24]

Further, the Department detailed the myriad challenges affecting the Nation's energy systems in its July 2025 "Resource Adequacy Report: Evaluating the Reliability and Security of the United States Electric Grid," issued pursuant to the President's directive in Executive Order 14262. The Department concluded that "[a]bsent decisive intervention, the Nation's power grid will be unable to meet projected demand for manufacturing, re-industrialization, and data centers driving artificial intelligence (AI) innovation."[25]

ORDER

FPA section 202(c)(1) provides that whenever the Secretary of Energy determines "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy," then the Secretary has the authority "to require by order . . . . such generation, delivery, interchange, or transmission of electric energy as in its judgment will best meet the emergency and serve the public interest."[26] This statutory language constitutes a specific grant of authority to the Secretary to require the continued operation of Culley Unit 2 when the Secretary has determined that such continued operation will best meet an emergency caused by a sudden increase in the demand for electric energy or a shortage of generation capacity.

---

[22] Executive Order No. 14156, 90 Fed. Reg. 8433 (Jan. 20, 2025) (*Declaring a National Energy Emergency*), https://www federalregister.gov/documents/2025/01/29/2025-02003/declaring-a-national-energy-emergency.

[23] *Id*.

[24] Executive Order No. 14262, 90 Fed. Reg. 15521 (Apr. 8, 2025) (*Strengthening the Reliability and Security of the United States Electric Grid*), https://www federalregister.gov/documents/2025/04/14/2025-06381/strengthening-the-reliability-and-security-of-the-united-states-electric-grid.

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

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

Such is the case here. As described above, the emergency conditions resulting from increasing demand and shortage from accelerated retirement of generation facilities will continue in the near term and are also likely to continue in subsequent years. This could lead to the loss of power to homes and businesses in the areas that may be affected by curtailments or power outages, presenting a risk to public health and safety. Given the responsibility of MISO to identify and dispatch generation necessary to meet load requirements, I have determined that, under the conditions specified below, continued additional dispatch of Culley Unit 2 is necessary to best meet the emergency arising from increased demand, determined shortage, and other causes, and serve the public interest under FPA section 202(c).

To ensure Culley Unit 2 will be available if needed to address emergency conditions, Culley Unit 2 shall remain in operation until March 23, 2026.

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

A. From December 23, 2025, MISO and CenterPoint Energy shall take all measures necessary to ensure that Culley Unit 2 is available to operate. For the duration of this Order, MISO is directed to take every step to employ economic dispatch of Culley Unit 2 to minimize cost to ratepayers. Following the conclusion of this Order, sufficient time for orderly ramp down is permitted, consistent with industry practices. CenterPoint Energy is directed to comply with all orders from MISO related to the availability and dispatch of Culley Unit 2.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters as determined by MISO, pursuant to paragraph A. MISO shall provide a daily notification to the Department (via AskCR@hq.doe.gov) reporting whether Culley Unit 2 has operated in compliance with the allowances contained in this Order.

C. All operations of Culley Unit 2 must comply with applicable environmental requirements, including but not limited to monitoring, reporting, and recordkeeping requirements, to the maximum extent feasible while operating consistent with the emergency conditions. This Order does not provide relief from any obligation to pay fees or purchase offsets or allowances for emissions that occur during the emergency condition or to use other geographic or temporal flexibilities available to generators.

D. By January 13, 2026, MISO is directed to provide the Department of Energy (via AskCR@hq.doe.gov) with information concerning the measures it has taken and is planning to take to ensure the operational availability of Culley Unit 2 consistent with this Order. MISO and CenterPoint Energy shall also provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time.

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

F. This Order shall not preclude the need for Culley Unit 2 to comply with applicable state, local, or Federal laws or regulations following the expiration of this Order.

G. Because this Order is predicated on the shortage of facilities for generation of electric energy and other causes, Culley Unit 2 shall not be considered a capacity resource.

H. This Order shall be effective from 11:59 PM Eastern Standard Time (EST) on December 23, 2025, and shall expire at 11:59 PM Eastern Daylight Time (EDT) on March 23, 2026, with the exception of applicable compliance obligations in paragraph D.

Issued in Denver, Colorado at 6:39 PM EST on this 23rd day of December 2025.

Chris Wright
Secretary of Energy

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

Indiana Utility Regulatory Commission
Chairman Jim Huston
Commissioner David Veleta
Commissioner David Ziegner

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. 202-26-46
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	)))))	Order No. 202-26-47

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

Exhibit 3
EFG Report



ENERGY FUTURES GROUP

RELIABILITY AND CAPACITY ASSESSMENT OF F.B. CULLEY 2 AND R.M. SCHAHFER 17 AND 18

Carlos Peña and Anna Sommer

January 21, 2026

Table of Contents

BACKGROUND 1

INTEGRATED RESOURCE PLANNING IN INDIANA 1

UTILITY-LEVEL CAPACITY POSITION IN EARLY 2026 AFTER PLANNED RETIREMENTS - CENTERPOINT ENERGY INDIANA SOUTH'S (CEIS) (F.B. CULLEY UNIT 2) 2

UTILITY-LEVEL CAPACITY POSITION IN EARLY 2026 AFTER PLANNED RETIREMENTS - NIPSCO (R.M. SCHAHFER UNITS 17 AND 18) 3

MISO RESOURCE ADEQUACY RULES AND SHORTFALL PROCEDURES 8

MISO ZONE 6 CAPACITY POSITION FOR PLANNING YEAR 2025/26 10

CONCLUSION 11

Background

The Department of Energy (DOE) has authority under section 202(c) of the Federal Power Act to order "temporary connections of facilities and such generation, delivery, interchange, or transmission of electric energy" when it finds that an emergency exists affecting the generation, transmission, or distribution of electricity. Historically, DOE used 202(c) sparingly to respond to short-term emergencies (e.g., hurricanes, major system disturbances), but in 2025 DOE began issuing and repeatedly extending 90-day orders to prevent planned retirements of the Campbell and Eddystone generators.

In CenterPoint Energy Indiana South's (CEIS) service territory, Culley 2, a 90-MW coal unit was planned for retirement on December 31, 2025. In Northern Indiana Public Service Company's (NIPSCO) service territory, R.M. Schahfer Units 17 and 18, two coal units, were scheduled to cease coal-fired operations by December 31, 2025.[1] On December 23, 2025, DOE issued a 202(c) Order forcing all three units to remain operational for an additional 90 days.

Integrated Resource Planning in Indiana

Indiana investor-owned utilities (IOUs) have engaged in integrated resource planning for well over a decade. As vertically integrated utilities who earn a return on equity from capital invested on behalf of their ratepayers, Indiana's IOUs have a significant incentive to construct generators in sufficient quantity to meet their customers' demands. Indiana IRPs look forward across a multi-decade period to determine capacity and energy needs under a variety of demand and other assumptions. These IRPs routinely evaluate retirement of aged generators and construction of new generators against continued operation of the legacy generators. A major objective of integrated resource planning is to make sure that a utility does not have an immediate need for capacity, as DOE contends here. Understanding the supply and demand balance is at the heart of the IRP exercise and directly addresses the concerns raised in DOE's order.

[1] Wesenberg, R. A. (2024, February). *2024-R.M.-Schahfer-Generating-Station-WDA*. (NIPSCO) Retrieved from https://www.nipsco.com/docs/librariesprovider11/rates-and-tariffs/ccr/r.m.-schahfer/r.m.-schahfer-generating-station-closure-and-post-closure-care/2024-r.m.-schahfer-generating-station-wda-statement-of-certification.pdf?sfvrsn=612bec51_1

Utility-Level Capacity Position in Early 2026 After Planned Retirements - CenterPoint Energy Indiana South's (CEIS) (F.B. Culley Unit 2)

CEIS's 2025 Integrated Resource Plan (IRP)[2] outlines a planned transition away from coal while maintaining resource adequacy through a diversified portfolio of new generation and demand-side resources. The plan includes the retirement of A.B. Brown Units 1 and 2 by 2023 and F.B. Culley Unit 2, a 90-MW coal unit, by the end of 2025. Rather than relying on large incremental renewable additions in the near term, CenterPoint's Preferred Portfolio emphasizes resources already secured through prior IRPs, including approximately 317 MW of wind from executed power purchase agreements and about 191 MW of Posey Solar, which entered service in 2025. Firm capacity is provided by two new 230-MW natural-gas combustion turbines (A.B. Brown Units 5 and 6), both of which entered commercial operation in 2025. The portfolio is complemented by continued investment in demand-side management (DSM), including approved energy efficiency and demand response programs that provide approximately 11–12 MW of gross annual demand savings, with DSM playing a growing role in meeting planning reserve margin requirements and mitigating future capacity needs.

In the 2025 IRP, CEIS presented a proposed balance of load and resources (Figure 1) indicating that total available capacity continues to exceed summer peak load plus reserve margin, with positive capacity surplus values indicated above the dotted lines. (Note that Figure 1 shows capacity from existing resources as well as those that CEIS intends to acquire or build.) The system relies primarily on natural gas, supplemented by solar, wind, storage, energy efficiency, demand response, and limited capacity purchases.

Importantly, the Reference Case continues to assume that F.B. Culley 2 will be retired while still maintaining adequate reserves in both summer and winter of 2026.

The winter results show a large and persistent capacity surplus above peak demand plus the planning reserve margin across the 20-year planning horizon, reflecting lower winter peak demand relative to summer and the contribution of the modeled resource portfolio, including owned and contracted natural gas–fired generation, wind and solar resources, demand-side programs, and limited market capacity purchases.

---

[2] CenterPoint Energy. (2025). *2025 Integrated Resource Plan*. Retrieved from https://www.centerpointenergy.com/en-us/Documents/Midwest/PUBLIC-CEIS-2025-IRP-Volume-1-of-2.pdf

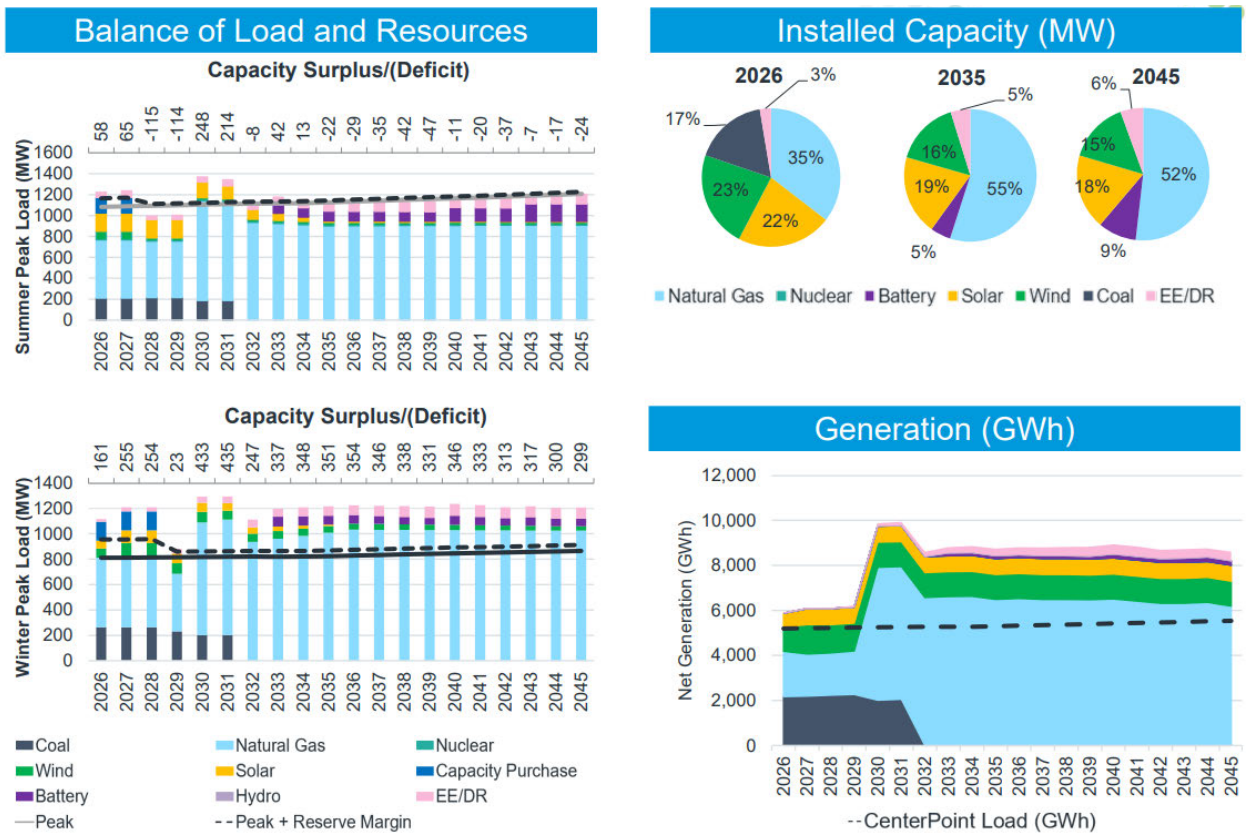


Figure 1. Summer and Winter Reference Case[3]

These results confirm that no seasonal shortfall is expected at any time during 2026. The projected summer capacity gaps in 2028 and beyond will be filled with capacity purchases or construction of a battery. CenterPoint plans to issue an RFP for battery capacity and expects that the battery may be more cost-effective than purchasing capacity.[3]

Utility-Level Capacity Position in Early 2026 After Planned Retirements - NIPSCO (R.M. Schahfer Units 17 and 18)

NIPSCO's 2021 IRP outlined a plan to retire all remaining coal units at the Schahfer station (Units 17 and 18) by 2023 and replace them primarily with wind, solar, battery storage, gas

[3] CenterPoint Energy. (2025). *Public Stakeholder Meeting #4 - October 23, 2025*. Retrieved from https://www.centerpointenergy.com/en-us/Documents/Midwest/IRP.Public.Stakeholder.Meeting.Presentation.11.06.2025.pdf

peakers, and demand-side resources.[4] Subsequent EPA and coal combustion residual filings indicate that the retirement date for Units 17 and 18 was extended to December 2025.[5] NIPSCO's latest planning documents also propose adding a new ~400 MW gas peaker to the Schahfer site and approximately 1,700 MW of renewable resources. [6]

Consistent with this strategy, NIPSCO has obtained IURC approval for multiple renewable projects, including Green River Solar (Cause No. 45818), Dunns Bridge Solar II (Cause No. 45936), Gibson Solar (Cause No. 45500), Fairbanks Solar (Cause No. 46028), Appleseed Solar (Cause No. 45887), and Carpenter Wind (Cause No. 45908).

NIPSCO's 2024 IRP confirms that its near-term plan maintains reliability and meets MISO's evolving resource adequacy rules even as major regulatory changes took effect in 2024. The plan assumes that Schahfer Units 17 and 18 retired at the end of 2025, with reliability maintained through previously approved transmission upgrades and approximately 2,100 MW of replacement resources (renewables plus a new 400-MW gas peaker) entering service. As is typical of vertically integrated utilities in the MISO footprint, NIPSCO's IRP contemplates both near- and long-term actions to maintain resource adequacy. It outlines a two-track strategy for new additions: a baseline set of resources that will be acquired regardless of whether large loads materialize, and a contingent set that proceeds only after large-load contracts are signed.[6] In either case, NIPSCO's intent is to ensure compliance with MISO's new direct loss of load (DLOL) capacity accreditation rule, discussed further below.

NIPSCO's 2024 IRP evaluates how its existing and planned accredited capacity compares with the required Planning Reserve Margin (PRM) under two different accreditation frameworks: the current MISO seasonal Resource Adequacy (RA) construct and the forthcoming DLOL accreditation method approved by FERC in October 2024. Figures 2a, 2b, 3a and 3b illustrate this comparison for both summer and winter, showing how NIPSCO's capacity position changes depending on which accreditation regime is applied.

---

[4] Northern Indiana Public Service Company (NIPSCO). (2021). *2021 Integrated Resource Plan*. NIPSCO. Retrieved from https://www.nipsco.com/docs/librariesprovider11/rates-and-tariffs/irp/2021-nipsco-integrated-resource-plan.pdf?sfvrsn=f6ae0251_6

[5] Mark Haney. 2025. TECHNICAL MEMORANDUM - RE: NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC R. M. SCHAHFER GENERATING STATION, WASTE DISPOSAL AREA 40 CFR §257.103(F)(2)(X) PART A DEMONSTRATION ANNUAL PROGRESS REPORT #01-25. Retrieved from https://www.nipsco.com/docs/librariesprovider11/rates-and-tariffs/ccr/r.m.-schahfer/r.m.-schahfer-generating-station-closure-and-post-closure-care/2025_rm-schahfer-generating-station_wda.pdf?sfvrsn=d4e7f251_3

[6] Northern Indiana Public Service Company (NIPSCO). (2024). *Integrated Resource Plan NIPSCO 2024*. NIPSCO. Retrieved from https://www.nipsco.com/docs/librariesprovider11/rates-and-tariffs/irp/nipsco_2024-irp.pdf

Figures 2a and 2b indicate that its accredited summer capacity in 2025 and 2026 stays close to or slightly above the required Planning Reserve Margin. In 2025, the figure shows a modest but positive margin, with total accredited resources, gas units, renewables, storage, DSM, and short-term market purchases, providing enough capacity to remain above the PRM even as Schahfer 17 and 18 near retirement. For 2026, NIPSCO's most recent IRP, which assumes Schahfer 17 and 18 retired at the end of 2025, shows that NIPSCO still maintains a comfortable capacity buffer. Overall, the IRP indicates no sign of a summer reliability shortfall in 2026 or even in 2027 and the retirement of Schahfer 17 and 18 does not create a capacity deficiency under the current accreditation rules. Figures 2a and 2b are NIPSCO's going-in position to its 2024 IRP (including existing and planned resources) and do not contemplate unidentified, additional resources that NIPSCO would plan to acquire as a result of its IRP to fill gaps in need in 2028 and beyond. This is a common view of capacity position to understand what needs the utility will address through its IRP process.

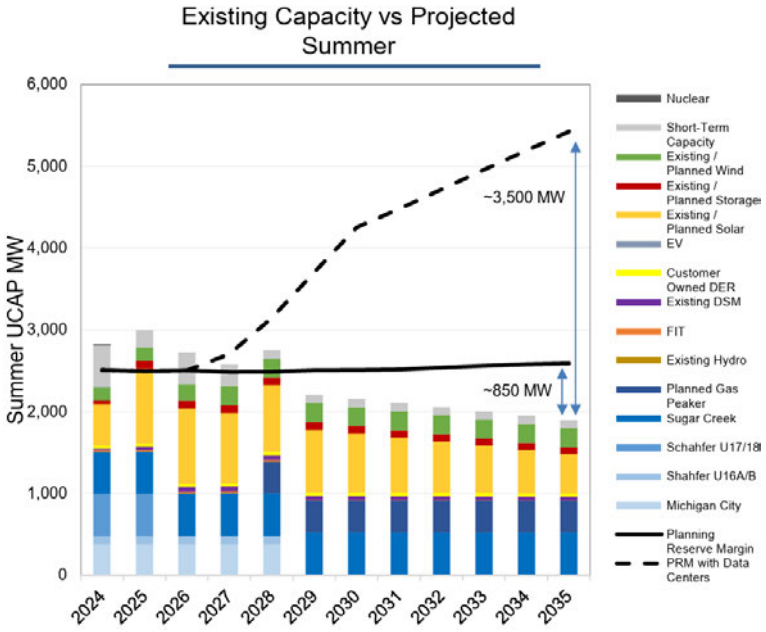


Figure 2a. Summer Resource Adequacy Assessment[6]

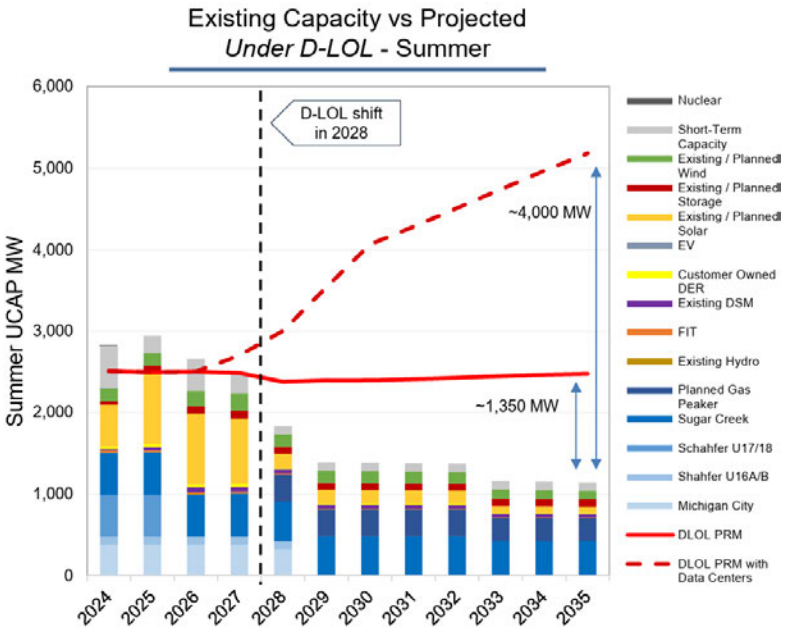


Figure 2b. Summer Resource Adequacy Assessment[6]

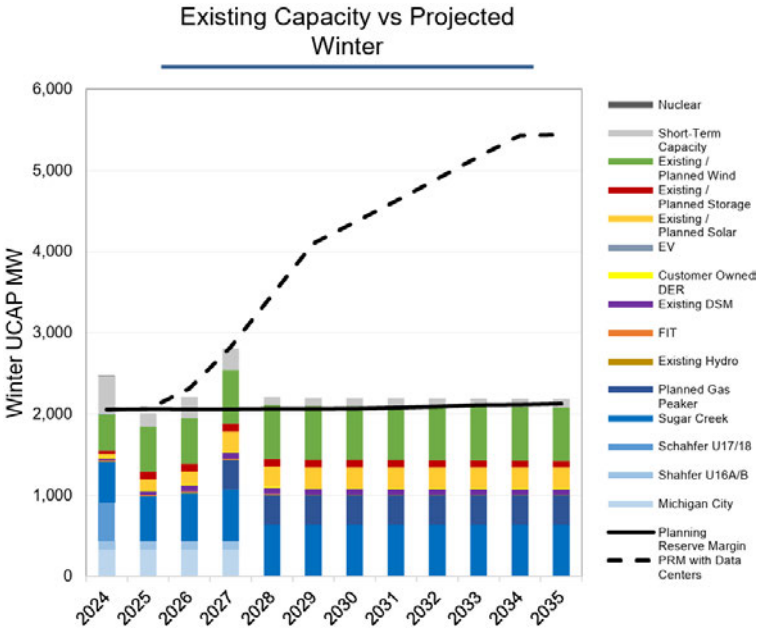


Figure 3a. Winter Resource Adequacy Assessment[6]

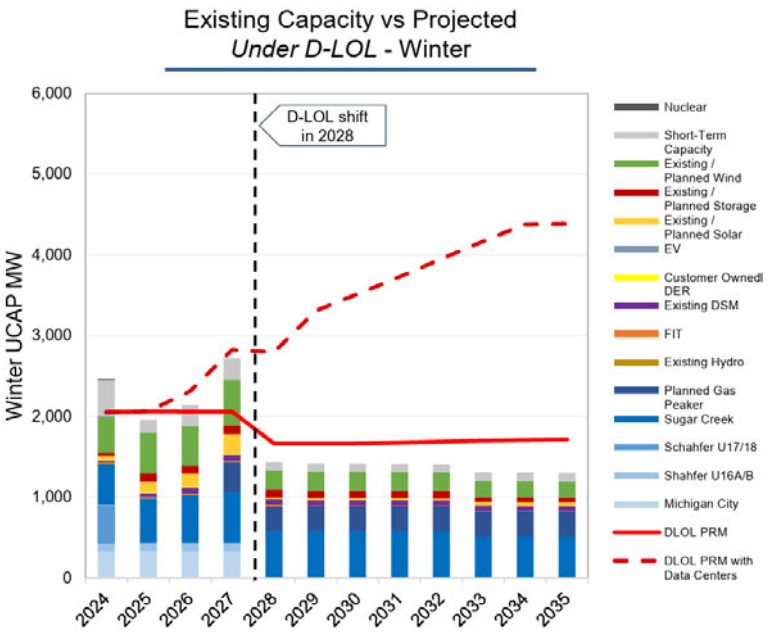


Figure 3b. Winter Resource Adequacy Assessment[6]

The forthcoming DLOL accreditation framework (which MISO will not in fact implement until Summer 2028) shows that the revised PRM requirements for summer 2025 and 2026 remain largely consistent with the results without DLOL. Although the dotted sensitivity lines reflect higher PRM needs under scenarios with significant data-center expansion, these increases occur after 2028 and therefore fall outside the period relevant to the Schahfer retirements.

Figure 3a shows that total accredited winter capacity is slightly above the PRM in 2025 and well above it in 2026. This is driven by higher winter accreditation for wind resources, combined with generally lower winter peak loads. As a result, the IRP demonstrates full winter resource adequacy compliance, with a buffer above the PRM throughout 2025, 2026, and 2027.

Notably, NIPSCO has been planning for the retirement of the Schahfer steam turbines for several years now. The retirement of those turbines will permit the reuse of interconnection rights for additional battery capacity and the Schahfer combustion turbines (CTs) that are currently under construction and will come into service in 2027. Continued operation of the Schahfer steam units once the new capacity is ready to come online will complicate the ability of the CTs and the batteries to inject power because they will be unable to complete the generator replacement interconnection process, which will likely make them ineligible to be counted as capacity resources until they can secure other firm transmission service.

In addition, NIPSCO appears to have ramped down the maintenance of the Schahfer steam units in anticipation of retirement as shown in Figure 4. This is a fairly routine practice since the return on major maintenance for units nearing the end of their life is often negative.

Maintenance expense has fallen from a high of $63 million in 2020 by almost half to $34 million in 2024, the most recent year for which data are available. Continued operation of the Schahfer units for an indefinite period would likely require major investment just to return the units to their normal operating condition.

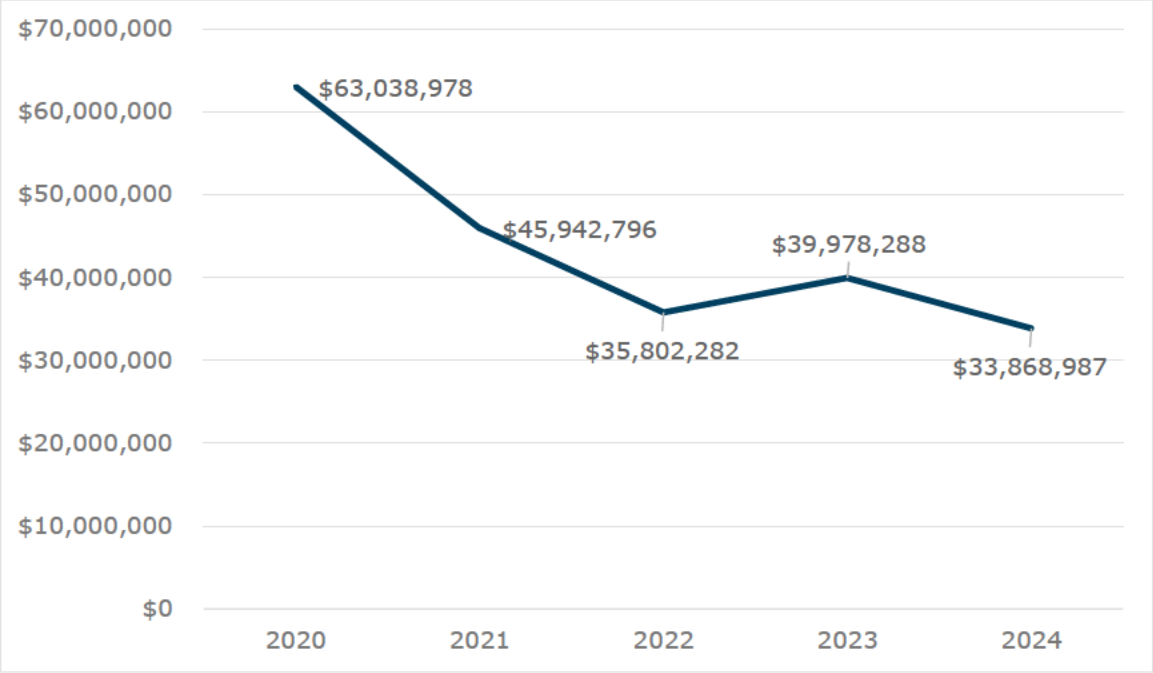


Figure 4. FERC Form 1 Reported Maintenance Expense at Schahfer Steam Units

MISO Resource Adequacy Rules and Shortfall Procedures

MISO's Resource Adequacy framework established in Module E-1 of its Tariff[7] and detailed in BPM-11[8] provides a structure for preventing and managing capacity shortfalls. The foundation of the program is the seasonal Planning Reserve Margin Requirement (PRMR), a total capacity obligation expressed in Zonal Resource Credits (ZRCs), which each Load Serving Entity (LSE) must meet. LSEs can meet this obligation either by providing evidence of capacity associated with resources they own or have contractual rights to via a Fixed

[7] MISO. (2025). *MISO Tariff*. MISO. Retrieved from https://www.misoenergy.org/legal/rules-manuals-and-agreements/tariff/
[8] MISO. (2025). *BPM 011 - Resource Adequacy*. MISO. Retrieved from https://www.misoenergy.org/legal/rules-manuals-and-agreements/business-practice-manuals/

Resource Adequacy Plan (FRAP) or bilateral contract, or by purchasing ZRCs via MISO's Planning Resource Auction (PRA). Target PRMRs are set annually using Loss-of-Load Expectation (LOLE) studies designed to maintain a reliability standard of 0.1 days per year, although the final PRMRs for each region will go up or down depending on the PRA clearing price: MISO requires LSEs to pay for more capacity when it is cheaper, and vice versa. MISO applies this construct across four seasons using Seasonal Accredited Capacity (SAC).

LSEs such as CEIS must demonstrate sufficient accredited capacity to satisfy their PRMR, while also meeting Local Clearing Requirements (LCRs), a separate category of capacity requirements designed to ensure that all cleared capacity is deliverable to each LSE's zone. MISO requires LSEs to either demonstrate they have achieved their PRMR or explicitly opt out of PRMR procurement ahead of the PRA by paying a Capacity Deficiency Charge (CDC). LSEs that opt out of PRMR procurement, or LSEs that are unable to meet their PRMR obligations, are assessed a CDC of 2.748 times the seasonal Cost of New Entry (CONE). CONE represents the cost of procuring a new generator that would be able to provide the short capacity. Under the Reliability-Based Demand Curve, a materially short zone in the PRA clears at or near CONE. Together, these mechanisms create strong financial incentives for LSEs to secure adequate capacity well in advance of the PRA and the operating period.[0]

When a resource committed for RA cannot perform due to retirement, suspension, catastrophic outage, ICAP deferral failure, or a planned outage exceeding 31 days, the Market Participant must procure replacement ZRCs. Failure to do so results in a Capacity Replacement Non-Compliance Charge (CRNCC), calculated using the Seasonal Auction Clearing Price plus the Daily Zonal CONE. MISO further enforces real-time performance through penalties on Load Modifying Resources (LMRs), including Demand Response and Behind-the-Meter Generation, when they fail to respond during declared emergencies.[7]

MISO relies on a structured escalation process to deploy resources including committed capacity resources. Operators issue Maximum Generation advisories and alerts, commit emergency resources, deploy LMRs through the Demand Side Resource Interface, and curtail non-firm exports before affecting firm load. If forecast demand and operating reserve requirements cannot be met through normal commitments, MISO first exhausts a defined set of pre-Energy Emergency Alert (EEA) actions, including committing all available generation and storage up to emergency limits, deploying emergency-only demand response, scheduling qualified external resources and emergency imports from neighboring systems, and initiating emergency energy purchases. If these actions are insufficient, MISO declares EEA-1 or EEA-2 and continues mitigation through emergency demand response dispatch, public appeals for load reduction, voltage reductions, and additional curtailment of load-modifying resources. Only after these measures fail to restore energy balance does MISO escalate to EEA-3, at which point firm load shedding becomes imminent or necessary. Scarcity pricing at the Value of Lost Load (VOLL) is applied when emergency imports,

emergency unit commitments, and all available reserves are insufficient to rebalance the system.[7]

MISO Zone 6 Capacity Position for Planning Year 2025/26

MISO's 2025 PRA for Planning Year (PY) 2025/26[9] provides a quantitative snapshot of Zone 6's resource adequacy position during the period when F.B. Culley 2 and Schahfer 17 and 18 were scheduled to retire. The Planning Resource Auction results for winter 2025–26 and spring 2026 in Table 1 indicate the following:

	Winter 2025-2026	Spring 2026
Zone 6 Final PRMR	18,685.7 MW	18,166.7 MW
Offer Submitted (Including FRAP)	14,679.5 MW	15,824.7 MW
Committed Capacity (offers cleared + FRAP) in Zone 6	14,331.5 MW	15,181.0 MW
Zone 6 LCR	11,074.8 MW	10,377.1 MW
Net Imports into Zone 6	4,354.1 MW	2,985.6 MW

Table 1. Planning Resource Auction Results for Winter 2025–26 and Spring 2026 Abbreviations: Planning Reserve Margin Requirement (PRMR), Fixed Resource Adequacy Plan (FRAP), Local Clearing Requirement (LCR)

For both seasons, Zone 6 maintains a substantial surplus of local committed capacity relative to its LCR, indicating that only a portion of the committed resources are needed to satisfy local adequacy obligations. Even before considering imports, committed capacity exceeds the LCR by approximately 3,257 MW (about 29%) in Winter 2025–26 and by 4,804 MW (about 46%) in Spring 2026, underscoring a comfortable local capacity position in both seasons.

In other words, these figures indicate that local deliverability is not at risk. Even following the Culley 2 and Schahfer 17 and 18 retirement, Zone 6 retains several gigawatts of surplus local capacity beyond what is required to meet the 2026 LCR.

Zone 6 does rely on imports; however, imports remain well below applicable limits in both seasons (see Table 2). Zonal Import Ability (ZIA) reflects the physical transmission capability to import power into the zone, while the Capacity Import Limit (CIL) represents the planning

[9] MISO. 2025. Planning Resource Auction Results for Planning Year 2025-26. Retrieved from https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf

constraint applied in the PRA to ensure reliable deliverability. Actual imports are well within both limits, indicating that Zone 6 is not import-constrained and does not rely excessively on imported capacity for resource adequacy.

	Winter 2025-2026	Spring 2026
Imports	4,354.1 MW	2,985.6 MW
ZIA	7,690 MW	9,176 MW
CIL	7,927 MW	9,457 MW
	Imports use about 23% of Final PRMR, but only ≈55% of CIL and ≈57% of ZIA.	Imports are about 16% of PRMR, and only ≈32% of CIL/ZIA.

Table 2. Zone 6 Imports Fall Below Import Limits

These figures demonstrate that, even after accounting for imports needed to meet PRMR, Zone 6 still has several gigawatts of unused import headroom (roughly 3.3 GW in winter and 6+ GW in spring). Neither these results nor the ones discussed above indicate a reliability emergency that constitute a need to keep F.B. Culley 2 and Schahfer 17 and 18 online.

Taken together, the PRA results for Winter 2025–26 and Spring 2026 indicate that Zone 6 meets its PRMR in both seasons without any RA shortfall. Local deliverability remains strong, with an estimated 3–5 GW of capacity above the LCR, and the imports required to satisfy PRMR are well within transfer limits, leaving substantial headroom. Collectively, these indicators support the conclusion that the planned retirements of F.B. Culley 2 and Schahfer 17 and 18 at the end of 2025 would not have created a resource adequacy concern for 2026.

In both Winter 2025/26 and Spring 2026, the MISO system exactly meets its Final PRMR of roughly 131 GW, with slightly more capacity offered than required and only modest reliance on transfers. In winter, approximately 1.7 GW of imports from external resource zones, together with about 0.6 GW of net exports from the South to the North. In spring, a similar pattern emerges, with about 1.5 GW of imports and 1.3 GW of South-to-North exports, all well within transfer capability. The uniform, relatively low Auction Clearing Price (ACPs) of $33.20/MW-day in winter and $69.88/MW-day in spring indicate that, even after accounting for these transfers, the system remains adequately supplied and does not face capacity shortfall risk in 2026.

Conclusion

MISO's planning resource auction and the Integrated Resource Plans of both NIPSCO and CEIS support a conclusion that the retirements of F.B. Culley 2 and Schahfer 17 and 18 at the end of 2025 would not give rise to a resource adequacy emergency during the first 90 days of 2026. Should circumstances change, MISO has emergency protocols in place to address

unplanned events such as loss of a generator or transmission line that do not rely on extending operation of these generators.

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. 202-26-46
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	)))))	Order No. 202-26-47

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

Exhibit 4
Powers January Declaration

SCHAHFER 17 & 18 AND CULLEY 2 DECLARATION OF BILL POWERS, P.E.

January 2026

I, Bill Powers, P.E., declare as follows:

1. I am the principal of Powers Engineering, an engineering firm that consults on issues related to the operation of, and control of pollution from, power plants, including coal-fired power plants. My office is located in San Diego, California. My professional and educational experience is summarized in the curriculum vitae attached to this declaration (Attachment A).

2. I received a Bachelor of Science degree from Duke University in Mechanical Engineering and a Master of Public Health degree in Environmental Sciences from the University of North Carolina. I am a registered engineer in the state of California.

3. I have been an independent engineering consultant with a focus on power systems since 1994. In prior employment, I received "Engineer of the Year" awards from ENSR Consulting and Engineering in 1991 (before ENSR merged with AECOM) and from the Naval Energy and Environmental Support Activity ("NEESA") office within the U.S. Navy in 1986 (before NEESA was subsumed by the Naval Facilities Engineering Service Center). I also received a "Productivity Award of Excellence" from the U.S. Department of Defense in 1985. I worked extensively on Navy and Marine Corps coal-fired power plant shore installations in the 1980s as a Navy civilian engineer.

4. I have over 40 years of experience in the fields of power plant operations and environmental engineering. My technical specialties include, among others: combustion

equipment permitting, testing, and monitoring; air emission control assessments; air pollution control equipment retrofit design/performance; and power plant cooling system conversion.

5. I have served as an engineering expert for a wide array of clients, including private companies, non-profits, and government entities, including the cities of Carlsbad, California and Houston and Dallas, Texas. In this role, I have provided expert testimony, conducted feasibility studies, and consulted on power plant engineering issues in a number of states, including Arkansas, California, Connecticut, Florida, Georgia, Kentucky, Maryland, Missouri, Nevada, North Carolina, New York, and Tennessee.

6. I have extensive experience with coal-fired power plants. In 2022, I provided expert testimony before the North Carolina Public Utility Commission regarding Duke Energy's proposed plan to maintain coal-fired units in its electric supply portfolio—a proposal the company advanced in part based on its belief that those units were necessary to meet winter peak demand. Throughout my career, I have consulted on the control of pollution from coal-fired power plants. Examples include serving as the lead engineer on a system and performance audit of continuous emissions monitoring systems at a coal-fired power plant in Nevada, and on a project to assess and address the root causes of opacity exceedances at Ameren Missouri's Labadie, Meramec, and Rush Island coal-fired power plants. I have also frequently provided expert testimony on coal-fired power plants. For example, I testified on air pollution controls at a coal-fired power plant in Massachusetts, and on the correlation between a Georgia coal-fired power plant's particulate matter emissions and opacity excursions, among other issues. I also served as a testifying expert on an evaluation of the air emissions limits and control technologies for a proposed coal-fired power plant in Arkansas. Finally, I have submitted or will submit expert declarations to the Department of Energy in the J.H. Campbell Generating Complex Section

202(c) matters (Michigan) in June 2025 and September 2025 and the Craig Station Section 202(c) matter (Colorado) in January 2026. In those declarations, I have documented the dramatic reduction in ongoing capital and major maintenance investments by the plant owners in the years prior to the planned permanent retirement date, and the impact of that lack of investment on the reliability of the unit(s).

7. I am also very familiar with "peaking" units, which are intended to ramp up and provide electricity during times of peak demand, such as during hot summer months. For example, in 2001, I prepared all aspects of the air permit applications for five 50 MW simple-cycle gas turbine installations in response to an emergency request by the California state government for additional peaking power.

8. I am familiar with the U.S. Department of Energy's ("DOE") December 23, 2025 order regarding R.M. Schahfer Units 17 and 18 (Order No. 202-25-12) ("Schahfer Order").

9. The R.M. Schahfer power plant ("Schahfer") consists of two coal-fired generating units, Unit 17 and Unit 18, each with a generating capacity of 361 MW, and two gas-fired combustion turbines, 78 MW Unit 16A and 77 MW Unit 16B.[1]

10. Northern Indiana Public Service Company LLC ("NIPSCO") is the owner and operator of R.M. Schahfer Generating Station. NIPSCO has submitted key filings concerning the operations of Schahfer Unit 17 and Unit 18 to state and federal regulatory bodies. As a result, I rely primarily on NIPSCO filings in this declaration.

11. The in-service dates for Schahfer Units 17 and 18 are 1983 and 1986, respectively.[2]

[1] NIPSCO 2024 Integrated Resource Plan ("IRP"), p. 102.
[2] NIPSCO 2024 IRP, p. 104.

12. The NIPSCO plan for Schahfer Units 17 and 18 was to retire the units by December 31, 2025.[3]

13. I am familiar with the U.S. Department of Energy's ("DOE") December 23, 2025 order regarding Culley Unit 2 (Order No. 202-25-13) ("Culley Order").

14. The F.B. Culley Generating Station ("Culley") consists of two coal-fired generating units, 90 MW Unit 2 and 270 MW Unit 3.[4]

15. CenterPoint Energy Indiana South ("CEIS") is the owner and operator of F.B. Culley Generating Station. CEIS has submitted key filings concerning the operation of Culley Unit 2 to state and federal regulatory bodies. As a result, I rely primarily on CEIS filings in this declaration.

16. The in-service date for Culley 2 was 1966.[5]

17. The initial CEIS plan was to permanently retire Culley 2 by the end of 2023. The planned retirement date was subsequently extended to December 31, 2025.[6]

18. I was asked by Earthjustice (legal counsel for certain Public Interest Organizations) to develop an opinion on: (A) the extent to which Schahfer 17 and 18 and Culley 2 can operate reliably after December 31, 2025; (B) whether Schahfer 17 and 18 and Culley 2 can operate effectively as peaking units; (C) the cost to rehabilitate Schahfer 17 and 18 to operate reliably for extended periods of time, (D) the environmental impact of continued operation of Schahfer 17 and 18 and Culley 2; and (E) easily attainable steps DOE can require to ensure

[3] "NIPSCO 2024 IRP, p. 1. "As previously planned, NIPSCO will complete the retirement and shutdown of Schahfer Units 17 and 18 by the end of 2025 and continue activities associated with the implementation of transmission system reliability upgrades."

[4] CEIS 2025 IRP, p. 12.

[5] Ibid.

[6] CEIS 2020 IRP, p. 254; CEIS 2023 IRP, pp. 235, 279, 280.

Schahfer 17 and 18 and Culley 2 operate in a manner consistent with environmental requirements and that minimizes adverse environmental impacts.

19. While there may be alternatives to the continued operation of Schahfer 17 and 18 and Culley 2 that are available to DOE to address the circumstances DOE describes in the Schahfer Order, my analysis notes but does not focus on these alternatives. As such, my analysis of alternatives should not be understood to be a comprehensive survey of alternatives. I also do not opine on the claimed energy emergency described in the Schahfer Order.

Section 1. The extent to which Schahfer 17 and 18 and Culley 2 can operate reliably beyond December 2025

A. Schahfer 17 and 18:

20. In my professional opinion, it is unlikely that Schahfer 17 and 18 can be depended upon to operate reliably beyond December 2025 as an emergency generation resource. Even before the scheduled retirement date of December 31, 2025, Schahfer 17 and 18 suffered from poor reliability. Nationally, the average coal unit forced outage rate in 2023 was 12.0 percent.[7] In contrast, Schahfer 17 and 18 had forced outage rates in 2024 of 18.8 percent and 13.2 percent, respectively[8]—well above the average coal unit forced outage rate. The forced outage rates in the first nine months of 2025 were similarly high for Schahfer 17 at 15.9 percent and spectacularly high for Schahfer 18 at 78.2 percent.[9] The current condition of Schahfer 18 is so bad that it must be rebuilt, according to the president of NIPSCO.[10] He also indicated in early

[7] NERC, *2024 State of Reliability*, p. 59 (June 2024).

[8] Indiana Utility Regulatory Commission ("IURC") Cause Nos. 38706 FAC 143 – 149, Direct Testimony of David Saffran on behalf of NIPSCO (Q1-Q4, 2024 and Q1-Q3, 2025), Att. 4-A, at 1.

[9] Ibid.

[10] NIPSCO president, statement at public event of the Indiana Utility Regulatory Commission in early December 2025, prior to the issuance of the US DOE Schahfer Order: "Unit 18 is in a forced outage; that one will take more time and effort to ultimately get it to where it needs to be, and at some point, if we do get a 202(c), and it continues, we'll likely have to do some work on 17 as well. […] We've taken some steps to be prepared – long lead time equipment, in particular, that ultimately would have to be ordered for us to come in. Frankly, that unit needs to be

December 2025 that it would take six months or more to have it running again and capable of running for an extended period of time (assuming the necessary investments are made). The NISPCO president indicated work would be needed on Schahfer 17 as well.[11]

21. The nature of the Schahfer 17 and 18 forced outages in 2024 and 2025 reflects the impact of worn and difficult-to-repair or replace coal unit components on operational reliability. Outages tended to be long and recurrent. Tables 1 and 2 document the longest Schahfer 17 and 18 outages by description and duration in 2024 and 2025 (first three quarters), respectively.

Table 1. Longest 2024 Outages, Schahfer 17 and 18 - Description and Duration[12]

Unit	Outage description	Total duration (hours)
17	• boiler tube leaks (2 outages)	1,645
18	• ESP problems (1 outage) • boiler tube leaks (3 outages) • pulverizer mill trip, extensive damage	147 159 614

Table 2. Longest 2025 Outages, Schahfer 17 and 18 - Description and Duration[13]

Unit	Outage description	Total duration (hours)
17	• boiler tube leaks (5 outages)	1,044
18	• boiler tube leak (1 outage) • steam turbine bearing vibration/failure • high turbine bearing vibration	150 2,980 1,996

22. NIPSCO determined in its 2018 IRP to retire the Schahfer (coal) Units 14, 15, 17, and 18 by the end of 2023. NIPSCO in fact retired the larger Units 14 and 15 in 2021, and

rebuilt. […] We're taking some steps to be able to do that, but it will take time; it can take 6 months or longer for us to ultimately be able to get that unit back to where it would need to be to operate for an extended period of time." IURC 2025 Winter Reliability Forum (December 2, 2025), https://www.youtube.com/watch?v=bCzALF4V45M, beginning at 51:35.

[11] Ibid.

[12] Direct Testimony of David Saffran on behalf of NIPSCO, IURC Cause No. 38706 FAC 143, FAC 145, FAC 146.

[13] Direct Testimony of David Saffran on behalf of NIPSCO, IURC Cause Nos. 38706 FAC 147, FAC 148, FAC 149.

confirmed its retirement plan for Schahfer 17 and 18 in its 2021 IRP. Subsequently, in 2022, NIPSCO resolved to retire Schahfer 17 and 18 in 2025, a plan it reaffirmed in its 2024 IRP.[14]

23. The high forced outage rates point to degraded Schahfer 17 and 18 reliability. Expected reliability will degrade further if the units are required to run for extended periods of time, are required to stop and start numerous times, or attempt to start up at an accelerated rate in response to extreme demand conditions.

24. Schahfer 17 has been operating for 43 years, Schahfer 18 for 40 years.[15] A typical coal unit has an economic design life of 30 to 40 years and a typical operational lifetime of 40 to 50 years.[16,17] As a power plant ages, the equipment degrades even though it is maintained and inspected, and it is unable to perform as well as brand-new equipment. It becomes necessary to upgrade or replace degraded equipment to a new condition.[18]

25. In the case of Schahfer 17 and 18, NIPSCO's stated objective was to keep the units operating until December 31, 2025 and shut them down at that time. The objective was *not* to maintain a high level of reliability beyond December 31, 2025. A high level of reliability would be necessary for Schahfer 17 and 18 to ramp up and work reliably under emergency demand conditions.

24. In particular, Schahfer 18's sharp increase in year-over-year forced outage rate from 2024 to 2025 is alarming, from 13.2 percent to 78.2 percent, especially if Schahfer 18 is expected to continue to operate past the scheduled December 31, 2025 retirement date. The

---

[14] NIPSCO 2024 IRP, p. 1.

[15] Ibid, p. 104.

[16] M. Hafner, G. Luciani, *The Palgrave Handbook of International Energy Economics*, p. 127 (2022).

[17] International Energy Agency, *The role of CCUS in low-carbon power systems*, p. 18 (2020).

[18] Intertek, *Update of Reliability and Cost Impacts of Flexible Generation on Fossil-fueled Generators*, prepared for Western Electricity Coordinating Council, May 12, 2020, p. 7: https://www.wecc.org/system/files/documents/anchor_data_set/2024/1r10726%20WECC%20Update%20of%20Reliability%20and%20Cost%20Impacts%20of%20Flexible%20Generation%20on%20Fossil.pdf.

increased forced outage rate was likely exacerbated by underspending on operations and maintenance (O&M) costs. Winding down O&M costs and failing to invest in long-term maintenance needs is common practice for end-of-life plants and is considered financially prudent. Plants such as R.M. Schahfer that have likely underspent on coal unit capital and/or O&M are at greater risk of future forced outages.[19]

27. In my professional opinion, it is unlikely that Schahfer 17 and 18 can reliably dispatch. As described above, NIPSCO has likely deferred capital and major maintenance spending, which is reflected in the plant's forced outage rate.

B. Culley 2:

28. It is unlikely that Culley 2 can be depended upon to operate reliably beyond December 2025 as an emergency generation resource. Even before the scheduled retirement date of December 31, 2025, Culley 2 was experiencing deteriorating reliability. As stated above, the national average coal unit forced outage rate in 2023 was 12 percent.[20] In contrast, Culley 2 had a forced outage rate of 32.4 percent in 2024 following years of steadily rising forced outage rates, as shown in Table 3.

Table 3. Culley 2 Forced Outage Rate,[21] 2020-2024

Unit	2020	2021	2022	2023	2024
Culley 2	6.3%	21.9%	26.6%	24.8%	32.4%

29. CEIS states that Culley 2 "has run past its useful life" as the basis for its planned retirement at the end of 2025.[22] This fact, and the rising forced outage rates, point to degraded

[19] Intertek, p. 7.
[20] NERC, *2024 State of Reliability*, p. 59 (June 2024).
[21] CenterPoint Energy, 2024 CEIS Electric Performance Report, p. 24.
[22] CEIS 2025 IRP, p. 30.

Culley 2 reliability. Expected reliability will degrade further if the unit is required to run for extended periods of time, is required to stop and start numerous times, or attempts to start up at an accelerated rate in response to extreme demand conditions.

30. Culley 2 has been operating for 60 years.[23] As stated above, a typical coal unit has an economic design life of 30 to 40 years and a typical operational lifetime of 40 to 50 years.[24,25] Also as stated above, a power plant's equipment will degrade in quality and performance over time, and upgrades and replacement will be necessary to maintain reliability.

31. The steady increase in the Culley 2 year-over-year forced outage rate is concerning, especially if Culley 2 will operate past the December 31, 2025 retirement date. The increased forced outage rate was likely exacerbated by underspending on O&M costs. CEIS's public filings show that its Culley 2 maintenance expenditure declined about 20% from 2022 to 2023 in account 512 (Maintenance of Boiler Plant).[26] Increased maintenance spending is necessary to minimize the effect of equipment degradation with age and changing operating regimes. Plants such as F.B. Culley that have likely underspent on capital investment and O&M are at greater risk of future forced outages.[27]

32. In my professional opinion, it is unlikely that Culley 2 can reliably dispatch.

Section 2. Whether Schahfer 17 and 18 and Culley 2 can operate effectively as a peaking units

A. Schahfer 17 and 18:

[23] Ibid, p. 12.

[24] M. Hafner, G. Luciani, *The Palgrave Handbook of International Energy Economics*, p. 127 (2022).

[25] International Energy Agency, *The role of CCUS in low-carbon power systems*, p. 18 (2020).

[26] CenterPoint Indiana response to data request OUCC 26.4 in IURC Cause No. 45990. Note that the 2023 expenditures are through September only. 2023 expenditures have been extrapolated to a full year to enable a direct comparison to 2022 expenditures.

[27] Intertek, p. 7.

33. In my opinion, Schahfer 17 and 18 cannot operate effectively as peaking units that would be dispatched with only a few hours of notice to meet an extreme demand condition.

34. Coal units generally, including Schahfer 17 and 18, cannot serve as peaking units that respond to extreme peak demand on short notice. Coal units are designed for baseload, around-the-clock operation.[28] Schahfer 17 and 18, started "cold" (room temperature), take a minimum of 23 hours to reach full load operation.[29] The ramp rate is slow to avoid excessive thermal stress on components exposed to heat. In contrast, utility-scale battery storage can dispatch from a cold start to full power in a matter of seconds.[30] Similarly, combustion gas turbines, designed for fast-response peaking duty, can go from a cold start to full power in 5 to 10 minutes.[31]

35. Coal units cannot respond to extreme demand events unless they are fully online several hours before the high demand situation occurs. In other words, coal units need substantial lead time to be fully operational at or before an extreme peak demand is reached. They cannot be dispatched from an offline "cold" status to address extreme emergency demand if an emergency is declared only a few hours before the demand must be met.

36. Grid demand increases rapidly on peak demand days. NIPSCO is a member of the Midcontinent Independent System Operator ("MISO"),[32] a regional transmission grid operator. MISO may have only a few hours' notice that an extreme peak demand day is

---

[28] CenterPoint Energy, 2025 IRP, p. 19. "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."

[29] NIPSCO response to data request CAC 1-013(c) from a CPCN case in 2024, IURC Cause No. 45947.

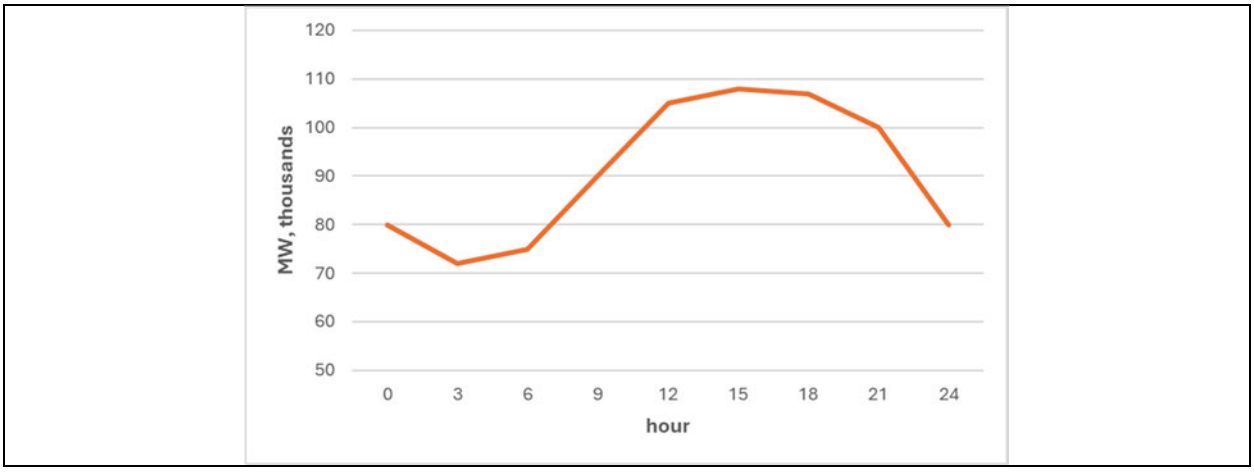
[30] NERC, *Energy Storage: Overview of Electrochemical Storage*, p. 1 (Feb. 2021). https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/Master_ESAT_Report.pdf ("BESS are a well suited technology to provide short-term grid contingency support (tens of seconds) . . . .").

[31] General Electric, *Get to know the LM6000* (webpage) (2025), https://www.gevernova.com/gas-power/products/gas-turbines/lm6000. ("With around five minutes to ramp up from start-up to full power . . . .").

[32] NIPSCO 2024 IRP, p. ES-3.

developing. The need to bring on additional generation resources to meet an extreme peak may be uncertain until the hours immediately prior to the actual peak. An example of this can be seen in Figure 1, which shows a modeled 24-hour demand curve for MISO on a representative high-demand summer day. Given their lengthy startup period, Schahfer 17 and 18 would not be able to meet a previously unanticipated exceptional peak demand, unless they were already online.

Figure 1. MISO 24-hour summer peak day demand curve[33] (MW)



37. Bringing Schahfer 17 and 18 from a cold start condition to full output to meet extreme demand would also be expensive. According to the National Association of Regulatory Utility Commissioners ("NARUC"), the estimated cost to "cold start" a coal-fired power plant is $417 per MW of capacity.[34] The net capacity of Schahfer 17 and 18 is 722 MW. Therefore, the estimated cost to start up Schahfer 17 and 18 from a cold start condition would be approximately $300,000. (722 MW × $417 per MW = $301,074).

38. Alternatively, instead of starting cold, NIPSCO could elect to run Schahfer 17 and 18 on a "Must Run" or "Self-Scheduled" basis, solely to be prepared for a potential near-term

[33] MISO, *Attributes Roadmap*, December 2023, p. 26 ("Base Case").

[34] NARUC, *Recent Changes to U.S. Coal Plant Operations and Current Compensation Practices* (Jan. 2020), https://www.osti.gov/servlets/purl/1869928, p. 16.

high-peak demand. That approach would be even more expensive and, as discussed below, highly polluting.

B. Culley 2:

39. Culley 2 cannot serve as peaking unit that respond to extreme peak demand on short notice. As stated above, coal units are designed for baseload, around-the-clock operation. As noted for Schahfer 17 and 18, coal units started cold may require 23 hours or more to reach full load operation.

40. CEIS is also a member of the MISO. As shown in Figure 1, MISO may have only a few hours' notice that an extreme peak demand day is developing. As with Schahfer, the need to bring on additional generation may be uncertain until the hours immediately prior to the actual peak. Culley 2 would not be able to meet a previously unanticipated exceptional MISO peak demand unless it was already online.

41. Bringing Culley 2 from a cold start condition to full output to meet extreme demand would also be expensive. Again, according to the NARUC, the estimated cost to "cold start" a coal-fired power plant is $417 per MW of capacity.[35] The net capacity of Culley 2 is 90 MW. Therefore, the estimated cost to start up Culley 2 from a cold start condition would be approximately $37,500. (90 MW × $417 per MW = $37,530). As with Schahfer 17 and 18, if Culley 2 were run on a "Must Run" or "Self-Scheduled" basis solely to be prepared for a potential demand peak, costs would be even higher.

Section 3. The cost to rehabilitate Schahfer 17 and 18 to operate reliably for extended periods of time

[35] Ibid, p. 16.

42. NIPSCO has projected the investment necessary to operate Schahfer 17 and 18 through 2027.[36] In IURC Cause No. 46120, NIPSCO's response to OUCC Data Request 9-004 Confidential Attachment C, NIPSCO calculates that operating Schahfer Units 17 and 18 beyond 2025 would require more than $1 billion of additional investment through 2027.

43. Utilities typically phase out capital and major maintenance spending on coal units scheduled for retirement a few years before the planned retirement date.[37] This makes fiduciary sense, as there would be little operating lifetime over which to recover the investment. However, as a result these units are less reliable in the period immediately prior to retirement.

Section 4. Environmental impact of continued operation of Schahfer 17 and 18

A. Schahfer 17 and 18:

46. Burning coal emits air pollutants and greenhouse gases. These pollutants include nitrogen oxides ("NO_x"), sulfur dioxide ("SO_2"), carbon dioxide ("CO_2"), and particulate matter ("PM") among others. NO_x is a lung irritant and a precursor to ozone formation.[38] SO_2 can harm the respiratory system and contribute to the formation of acid rain.[39] PM emissions can cause decreased lung function and increased respiratory symptoms.[40] In addition, NO_x, SO_2, and PM_{10}

[36] NIPSCO response to data request OUCC 9-004 from a general rate case in 2024-2025, IURC Cause No. 46120. "Pulled from the 2024 analysis, OUCC Request 9-004 Confidential Attachment C shows NIPSCO's calculation of what it considers a reasonable estimate, based on presently available information, of the total investment cost necessary to operate Schahfer Units 17 and 18 through 2027."

[37] See W. Powers June 2025 Declaration in J.H. Campbell Section 202(c) matter (DOE Order No. 202-25-3).

[38] U.S. EPA, *Basic Information about NO_2*, webpage accessed August 31, 2025: https://www.epa.gov/no2-pollution/basic-information-about-no2.

[39] U.S. EPA, *Sulfur Dioxide Basics*, webpage accessed August 31, 2025: https://www.epa.gov/so2-pollution/sulfur-dioxide-basics.

[40] U.S. EPA, *Health and Environmental Effects of Particulate Matter (PM)*: https://www.epa.gov/pm-pollution/health-and-environmental-effects-particulate-matter-pm.

contribute to the formation of atmospheric haze, which reduces visibility.[41] Through its regional haze visibility modeling, Indiana found that air pollution from R,M, Schahfer is a contributor to visibility impairment.[42] CO_2 emissions are the primary cause of global warming.[43]

47. Large quantities of these pollutants and greenhouse gases will enter the atmosphere if uncontrolled. R.M. Schahfer Generating Station's Title V air permit sets out the emission limits and other requirements the facility must comply with to reduce air pollution from coal combustion and related operations.[44]

48. Coal-burning power plants must include air emission control equipment to reduce the pollutants in the coal boiler exhaust gas stream. The equipment still allows some level of pollution to be emitted, but it reduces the amount of pollutants entering the atmosphere.

49. The air cleaning equipment at Schahfer 17 and 18 includes electrostatic precipitators (ESPs), wet limestone scrubbers, and low-NO_x burners with over-fire air.[45] ESPs remove PM from the boiler exhaust gas. Wet limestone scrubbers (also known as flue gas desulfurization) remove SO_2. The low-NO_x burner system is intended to limit the amount of NO_x generated at the point of combustion in the boiler.

50. Tables 2a and 2b summarize the projected SO_2, NO_x, CO_2, and PM emissions from Schahfer 17 and 18 for the 90-day period from January 1, 2026 to March 31, 2026, assuming the same level of Schahfer 17 and 18 electricity generation as recorded in January,

---

[41] Colorado APCD, *Best Available Retrofit Technology (BART) Analysis – Tri-State Craig Station Units 1 and 2*, p. 2. [EPA-R08-OAR-2018-0015-0004]

[42] U.S. EPA, Docket No. EPA-R05-OAR-2021-0963, Technical Support Document for the Federal Register Notice of the Proposed Rule for Air Plan Approval; Indiana; Regional Haze Plan for the Second Implementation Period April 22, 2025, pp. 14-15,

[43] U.S. EPA, *Carbon Dioxide Emissions*, February 23, 2025: https://www.epa.gov/ghgemissions/carbon-dioxide-emissions.

[44] IDEM, Part 70 Operating Permit Renewal (Title V), NIPSCO - R.M. Schahfer Generating Station, February 4, 2025.

[45] Ibid, p. 9.

February, and March of 2025. The basis for this projection is the operating profile of the three-unit J.H. Campbell coal plant that was scheduled to retire on May 31, 2025 but continues to operate under a 202(c) order. The plant continues to operate as it did before the Schahfer Order. In fact, the 265 MW Campbell Unit 1 actually produced more electricity in August 2025 operating under the Department of Energy's 202(c) order than it did in August 2024.[46] However, it is important to note that, as noted above, Schahfer 18 needs repairs that likely will take beyond 90 days to complete. If Schahfer 18 actually cannot operate in the 90-day period of the Schahfer Order, then the Unit 18 figures in Tables 4a and 4b below are not applicable.

51. As shown in Table 4a, if Schahfer 17 and 18 operated during the 90-day period of the Schahfer Order with the same level of production they maintained in January – March 2025, more than 140,000 pounds of SO_2, and 675,000 pounds of NO_x would be emitted over the 90-day period. As shown in Table 4b, 535,000 tons of CO_2 and nearly 104,000 pounds of PM would be emitted. None of these emissions could occur if Schahfer 17 and 18 had been permanently retired by December 31, 2025.

Table 4a. Projected Schahfer 17 and 18 SO_2, and NO_x Emissions,[47] 90-Day Order

Month	Production,[48] MWh		Fuel usage, MMBtu		SO_2 emissions, lbs	NO_x emissions, lbs
	17	18	17	18		
January 2026	98,307	136,987	1,232,386	1,265,210	67,435	324,687
February 2026	108,906	10,672	1,415,690	157,053	42,464	204,457
March 2026	84,103	0	1,124,327	0	30,357	146,163
90-day total:	291,316	144,373	3,772,403	1,422,263	140,256	675,307

Source of SO_2 and NO_x emission factors, EPA CAMPD database 2025: Schahfer 17 & 18: SO_2 = 0.027 lb/MMBtu, NO_x = 0.13 lb/MMBtu.

[46] EIA Form 923, Page 4 Generator Data, 2024 and 2025 (through September): https://www.eia.gov/electricity/data/eia923/.

[47] For Schahfer 17 and 18 fuel usage, SO_2, NO_x and CO_2 emission rates, see: EPA Clean Air Markets Pollutant Database (CAMPD) 2025: https://campd.epa.gov/data/custom-data-download.

[48] EIA-923 Monthly Generation and Fuel Consumption Time Series File, 2025 September, Page 4 – Generator Data, January – September 2025.

Table 4b. Projected Schahfer 17 and 18 CO_2 and PM emissions,[49] 90-Day Order

Month	Production, MWh		Fuel usage, MMBtu		CO_2 emissions, tons	PM emissions, lbs
	17	18	17	18		
January 2026	98,307	136,987	1,232,386	1,265,210	257,252	49,952
February 2026	108,906	10,672	1,415,690	157,053	161,993	31,455
March 2026	84,103	0	1,124,327	0	115,806	22,487
90-day total:	291,316	144,373	3,772,403	1,422,263	535,051	103,893

Sources: (1) CO_2 emission factors: EPA CAMPD database 2025, Schahfer 17 & 18: CO_2 = 0.103 tons/MMBtu (2) PM emission factors, EPA eGrid database 2021: Schahfer 17 PM = 0.020 lb/MMBtu, Schahfer 18 PM = 0.022 lb/MMBtu.

B. Culley 2:

52. The air cleaning equipment at Culley 2 includes an electrostatic precipitator (ESP), wet limestone scrubber, and low-NO_x burners with over-fire air.[50] As noted above, an ESP removes PM from the boiler exhaust gas. Wet limestone scrubbers (also known as flue gas desulfurization) remove SO_2. The low-NO_x burner system is intended to limit the amount of NO_x generated at the point of combustion in the boiler.

53. Tables 2a and 2b summarize the projected SO_2, NO_x, CO_2, and PM emissions from Culley 2 for the 90-day period from January 1, 2026 to March 31, 2026, assuming the same level of Culley 2 electricity generation as recorded in January, February, and March of 2025. The basis for this projection is the operating profile of the three-unit J.H. Campbell coal plant that was scheduled to retire on May 31, 2025 but that continues to operate under a 202(c) order. As previously noted, the operating profile of the Campbell plant post-order remains similar to its pre-order operating profile.

54. As shown in Table 5a, more than 112,000 pounds of SO_2, and 160,000 pounds of NO_x would be emitted during the 90-day Culley Order. As shown in Table 5b, more than 60,000

[49] For Schahfer 17 and 18 PM emission rates, see EPA eGrid database 2021: https://www.epa.gov/egrid/egrid-pm25

[50] IDEM, Part 70 Operating Permit Renewal (Title V), Southern Indiana Gas and Electric Company (SIGECO) F.B. Culley Generating Station, July 7, 2025, p 7.

tons of CO_2 and nearly 153,000 pounds of PM would be emitted. None of these emissions could occur if Culley 2 had been permanently retired by December 31, 2025.

Table 5a. Projected Culley 2 SO_2, and NO_x Emissions,[51] 90-Day Order

Month	Production,[52] MWh	Fuel consumption, MMBtu	SO_2 emissions, lbs	NO_x emissions, lbs
January 2026	17,922	243,238	46,215	65,674
February 2026	17,352	289,271	54,961	78,103
March 2026	2,602	59,721	11,347	16,125
90-day total:	37,876	592,229	112,524	159,902

Source of SO_2 and NO_x emission factors, EPA CAMPD database 2025: Culley 2: SO_2 = 0.19 lb/MMBtu, NO_x = 0.27 lb/MMBtu.

Table 5b. Projected Culley 2 CO_2, and PM Emissions,[53] 90-Day Order

Month	Production, MWh	Fuel consumption, MMBtu	CO_2 emissions, tons	PM emissions, lbs
January 2026	17,922	243,238	24,810	58,377
February 2026	17,352	289,271	29,506	78,103
March 2026	2,602	59,721	6,092	16,125
90-day total:	37,876	592,229	60,407	152,605

Sources: (1) CO_2 emission factors: EPA CAMPD database 2025, Culley 2: CO_2 = 0.102 tons/MMBtu (2) PM emission factor, EPA eGrid database 2021: Culley 2 PM = 0.24 lb/MMBtu.

Section 5. Easily attainable steps DOE can require to ensure Schahfer 17 and 18 operations are consistent with environmental requirements and minimize adverse environmental impacts

A. Schahfer 17 and 18:

55. MISO has forecast an adequate 2026 planning reserve margin ("PRM"), without operation of Schahfer 17 and 18 and Culley 2, to meet peak demand conditions in the winter of

[51] For Culley 2 fuel usage, SO_2, NO_x and CO_2 emission rates, see: EPA Clean Air Markets Pollutant Database (CAMPD) 2025: https://campd.epa.gov/data/custom-data-download.

[52] EIA-923 Monthly Generation and Fuel Consumption Time Series File, 2025 September, Page 4 – Generator Data, January – September 2025.

[53] For Culley 2 PM emission rate, see EPA eGrid database 2021: https://www.epa.gov/egrid/egrid-pm25.

2025-2026 and the summer of 2026.[54,55] For this reason, Schahfer 17 and 18 should only be dispatched if and when MISO forecasts the potential for actual demand to substantially exceed the normal peak forecast.

56. The Schahfer Generation Station Title V permit requires that the facility ", , , must comply with all conditions of this permit. Noncompliance with any provisions of this permit is grounds for enforcement action . . . It shall not be a defense for the Permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit."[56] As described above, NIPSCO has been limiting its operational expenditures in light of Schahfer 17 and 18's expected retirement. In my opinion, for DOE's Schahfer Order to be consistent with environmental requirements, NIPSCO must demonstrate, prior to restarting Schahfer 17 and 18, that the (1) ESPs are in sound condition, and (2) that wet limestone scrubbers and ultra-low NO_x burners are in good working order. Absent such a demonstration, DOE's order may result in power being generated in a manner inconsistent with good air pollution control practices for minimizing emissions.

[54] NERC, *2025–2026 Winter Reliability Assessment*, November 2025, p. 11 and p. 17. The MISO anticipated reserve margin in the winter of 2025-2026 is 49.5%, compared to a reference margin level (RML) of ~40%.

[55] NERC, *2024 Long-Term Reliability Assessment, December 2024* (corrected July 11, 2025), Figure 3: MISO Planning Reserve Margin–Summer, p. 13. The 2026 summer anticipated (planning) reserve margin is 17%, compared to a RML, the minimum adequate PRM, of 9%. "To establish the RMLs that define the minimum (planning) reserve margins for resource adequacy, MISO performs its annual probabilistic Loss-of-Load Expectation (LOLE) Study per MISO tariff. The study produces seasonal RMLs for the upcoming planning year that are used in MISO's planning resource auction. These RMLs are calculated such that they define the minimum PRM that will meet a LOLE of 1 day in 10 years."

[56] IDEM, Part 70 Operating Permit Renewal (Title V), NIPSCO - R.M. Schahfer Generating Station, February 4, 2025, p. 1.

57. Problems with the ESPs on Schahfer 17 and 18, including broken high voltage wires and flyash buildup, have been the source of repeated outages in the last two years.[57] Regular replacement of broken ESP wires is necessary to assure good performance of the ESP. Typical operational problems with wet limestone scrubbers include: scale formation in the scrubber vessels, poor utilization of the limestone reagent, and inadequate spray nozzle efficiency.[58] Regular maintenance of (1) spray nozzles to address plugging and wear, and (2) limestone grinding mills to assure an optimum limestone particle size, is essential to maintaining the control efficiency of the wet scrubber. Ultra-low NO_x burners are subject to degradation from (1) erosion wear at the burner tip and (2) less than optimum pulverized coal combustion efficiency due to wear in the coal pulverizers.[59] Regular maintenance of the ultra-low NO_x burners and the associated coal pulverizers is essential to minimize NO_x formation in the boiler.

58. I could not locate information in the public record on (1) the condition of the Schahfer 17 and 18 ESPs, (2) the operational history and current condition of the Schahfer 17 and 18 wet limestone scrubbers, or (3) the Schahfer 17 and 18 ultra-low NO_x burners and overfire air system. It cannot be assumed that the Schahfer 17 and 18 pollution control equipment is in good working order and will operate reliably to control the facility's emissions beyond December 2025.

59. It is my opinion that DOE should require verification of the good working order of the Schahfer 17 and 18 air emission control systems before authorizing Schahfer 17 and 18 to

---

[57] IURC Cause Nos. 38706 FAC 142 and FAC 143, Direct Testimony of David Saffran on behalf of NIPSCO (Q4, 2023 and Q1, 2024), Att. 4-A, at 1. "Two years" refers to the two most recent years of available outage records, from Q4 2023 through Q3 2025.

[58] Power Engineering, *Wet-Limestone Scrubbing Fundamentals*, August 1, 2006: https://www.power-eng.com/operations-maintenance/wet-limestone-scrubbing-fundamentals/.

[59] Power Magazine, *To optimize performance, begin at the pulverizers*, February 2007; Riley Power, *Advanced Erosion Protection Technology Provides Sustained Low NOx Burner Performance*, April 2004.

operate under extreme demand conditions. DOE should also require that if air permit limits for PM, NO_x, or SO_2 are exceeded during operation of Schahfer 17 and 18, as registered on the continuous PM, NO_x, or SO_2 monitors installed on the units, then unit(s) will be shut down.

60. It is also my opinion that there are alternatives to running Schahfer 17 and 18 to meet an extreme peak demand that would produce far less environmental harm. As previously noted, battery storage and (natural gas and oil-fired) combustion gas turbines are examples of resources that are ideally suited to addressing rapidly varying, peak demand conditions. Hydropower can also respond quickly to changing demand conditions. In 2026, NIPSCO will have at its disposal 563 MW of gas -fired generation, 16 MW of hydropower, and approximately 620 MW of demand response to address fast-changing demand on its system.[60]

61. Any air emissions that result from running Schahfer 17 and 18 would not occur if the units are retired. Additionally, Schahfer 17 and 18 consume approximately 21.7 million gallons of water per day of operation at their combined net capacity of 722 MW.[61]

62. Finally, any coal burned will produce coal ash that will have to be stored/disposed of onsite. That is an additional impact that would not occur if Schahfer 17 and 18 are retired. The EPA's 2015 CCR (Coal Combustion Residuals) Rule regulates CCRs.[62] NIPSCO has completed several CCR projects and has active ongoing projects to comply with the 2015 CCR Rule.[63] NIPSCO states that retirement of Schahfer Generating Station Units 17 and 18 by 2025

[60] NIPSCO 2024 IRP at Summary p. 7; NIPSCO 2025-2026 Planning Reserve Margin Report, p. 4.

[61] IDEM, NPDES Permit No. IN0053201, Northern Indiana Public Service Company LLC - R. M. Schahfer Generating Station, September 24, 2020, pdf p. 57 ("The R.M. Schahfer facility's design intake flow (DIF) rate is 57.7 MGD, almost all of which is used for non-contact cooling water.") and p. 94 ("For the period 2015 through 2019, the actual intake flow (AIF) was 21.7 MGD.").

[62] NIPSCO 2024 IRP, p. 204.

[63] NIPSCO, (webpage) Data and information about CCRs, 2026: https://www nipsco.com/our-company/about-us/our-environment/ccr-rule-compliance.

will avoid significant capital cost needed to comply with the 2015 CCR Rule and other environmental requirements.[64]

B. Culley 2:

63. Again, MISO has forecast an adequate 2026 PRM without operation of Culley 2 and Schahfer units 17 and 18 to meet peak demand conditions.[65]

64. The Culley Generation Station Title V permit requires that the facility will operate "in accordance with good air pollution control practices for minimizing excess emissions."[66] The Title V permit also requires that the ESP be operated at all times Unit 2 is combusting coal "to maximize PM emission reductions, consistent with the operational and maintenance limitations of the unit."[67] In my opinion, for DOE's Order to be consistent with environmental requirements, CEIS must demonstrate, prior to restarting Culley 2, that the (1) ESP is in sound condition, and (2) that wet limestone scrubber and ultra-low NO_x burners are in good working order. Absent such a demonstration, DOE's order may result in power being generated in a manner inconsistent with good air pollution control practices for minimizing emissions.

65. Problems with the ESPs include broken wires that compromise performance and ash build-up caused by flyash removal difficulties.[68] Regular replacement of broken ESP wires is necessary to assure good performance of the ESP. Again, typical operational problems with wet limestone scrubbers include: scale formation in the scrubber vessels, poor utilization of the

[64] NIPSCO 2024 IRP, p. 204.

[65] OMS and MISO, *OMS-MISO Survey Results* (Updated June 6, 2025), https://cdn.misoenergy.org/20250606%20OMS%20MISO%20Survey%20Results%20Workshop%20Presentation702311.pdf.

[66] Culley Generating Station Title V air permit, July 7, 2025, p. 30.

[67] Ibid, p. 39.

[68] See (for representative examples of ESP problems): IURC Cause Nos. 38706 FAC 142 and FAC 143, Direct Testimony of David Saffran on behalf of NIPSCO (Q4, 2023 and Q1, 2024), Att. 4-A, at 1.

limestone reagent, and inadequate spray nozzle efficiency.[69] Regular maintenance of (1) spray nozzles to address plugging and wear, and (2) limestone grinding mills to assure an optimum limestone particle size, is essential to maintaining the control efficiency of the wet scrubber. Ultra-low NO_x burners are subject to degradation from (1) erosion wear at the burner tip and (2) less than optimum pulverized coal combustion efficiency due to wear in the coal pulverizers.[70] Regular maintenance of the ultra-low NO_x burners and the associated coal pulverizers is essential to minimize NO_x formation in the boiler.

66. I could not locate information in the public record on (1) the condition of the Culley 2 ESP, (2) the operational history and current condition of the Culley 2 wet limestone scrubber, or (3) the Culley 2 ultra-low NO_x burners and overfire air system. It cannot be assumed that the Culley 2 pollution control equipment is in good working order and will operate reliably to control the facility's emissions beyond December 2025.

67. It is my opinion that DOE should require verification of the good working order of the Culley 2 air emission control systems before authorizing Culley 2 to operate under extreme demand conditions. DOE should also require that if air permit limits for PM, NO_x, or SO_2 are exceeded during operation of Culley 2, as registered on the continuous PM, NO_x, or SO_2 monitors installed on the units, then unit will be shut down.

68. It is also my opinion that there are alternatives to running Culley 2 to meet an extreme peak demand that would produce far less environmental harm. As previously noted, battery storage and combustion gas turbines are examples of resources that are ideally suited to

[69] Power Engineering, *Wet-Limestone Scrubbing Fundamentals*, August 1, 2006: https://www.power-eng.com/operations-maintenance/wet-limestone-scrubbing-fundamentals/.

[70] Power Magazine, *To optimize performance, begin at the pulverizers*, February 2007; Riley Power, *Advanced Erosion Protection Technology Provides Sustained Low NOx Burner Performance*, April 2004.

addressing rapidly varying, peak demand conditions. CEIS recently built the new A.B. Brown combustion turbine plant (460 megawatts), which reached commercial operation in 2025.[71]

69. Any air emissions that result from running Culley 2 would not occur if the plant is retired.

70. Additionally, Culley 2 uses a once-through cooling system drawing water from the Ohio River. The Culley 2 water withdrawal rate is approximately 45 million gallons per day on average.[72]

72. Finally, any coal burned will produce coal ash that will have to be stored/disposed of onsite. That is an additional impact that would not occur if Culley 2 is retired.

73. In my opinion, a coal unit would be the last alternative to consider for a peaking power application due to its slow ramp rate and high environmental impact.

I declare under penalty of perjury under the laws of the United States, pursuant to 28 U.S.C. § 1746, that the foregoing is true and correct to the best of my knowledge.

Executed on this 21 day of January 2026, in San Diego, California.

Bill Powers, P.E.

Bill Powers, P.E.
Powers Engineering
4452 Park Blvd., Suite 209
San Diego, CA 92116

[71] CEIS 2025 IRP, p. 12.

[72] IDEM, NPDES Permit No. IN0002259 Permit Modification, SIGECO F.B. Culley Generating Station, May 3, 2024, pdf p. 44. Average once through cooling outfall flow to the Ohio River is 181.6 million gallons per day (MGD). 90 MW Unit 2 is 25% of the combined capacity of 90 MW Unit 2 and 270 MW Unit 3. Therefore, assume the average Unit 2 cooling water flow = 0.25 × 181.6 MGD = 45.4 MGD.

Attachment A

BILL POWERS, P.E.

PROFESSIONAL HISTORY

Powers Engineering, San Diego, CA 1994-
ENSR Consulting and Engineering, Camarillo, CA 1989-93
Naval Energy and Environmental Support Activity, Port Hueneme, CA 1982-87
U.S. Environmental Protection Agency, Research Triangle Park, NC 1980-81

EDUCATION

Bachelor of Science – Mechanical Engineering, Duke University
Master of Public Health – Environmental Sciences, University of North Carolina

PROFESSIONAL AFFILIATIONS

Registered Professional Mechanical Engineer, California (Certificate M24518)
Registered Professional Engineer, Missouri (Certificate 2018039156)
American Society of Mechanical Engineers
Institute of Electrical and Electronics Engineers

TECHNICAL SPECIALTIES

Forty years of experience in:

- Air quality and utility commission proceedings - expert witness
- Distributed solar photovoltaics (PV) siting and regional renewable energy planning
- Power plant cooling system conversion and air emission control assessments
- Combustion equipment permitting, testing and monitoring
- Air pollution control equipment retrofit design/performance testing
- Petroleum refinery air engineering and testing
- Latin America environmental project experience

RECENT AIR QUALITY AND UTILITY COMMISSION PROCEEDINGS

Compressor Station Gas Turbine Air Emission Controls. Assessed the air emission controls and siting issues related to two proposed pipeline compressor station projects in the vicinity of Nashville, Tennessee utilizing Solar Turbines, Inc Titan gas turbines. The result, based on application of a Reasonably Available Control Technology (RACT) requirement, was the reduction of the proposed air permit nitrogen oxides (NOx) emission limit from 25 parts per million (ppm) to 9 ppm.

Combined Heat and Power Plant Gas Turbine Air Emission Controls. Evaluated the air emission controls proposed for a combined heat and power (CHP) plant at Duke University that would utilize Solar Turbines, Inc Titan gas turbine. Applicant proposed a 25 ppm NO_x limit using dry low-NO_x combustion as Best Available Control Technology (BACT) in its Certificate of Public Convenience and Necessity (CPCN) application to the North Carolina Utilities Commission. Argued that NO_x BACT for the CHP plant should be use of selective catalytic reduction (SCR) to achieve a 2 ppm NO_x emission limit. Applicant withdrew its CPCN application.

SDG&E 36-Inch Transmission Pipeline. Expert witness for non-profit client advocating that existing 16-inch pipeline did not require replacement with new $600 million 36-inch pipeline. Underscored in testimony that SDG&E had recently completed extensive inline inspection of existing 16-inch pipeline and found that pipeline was in good condition for long-term operation at 512 psig transmission pressure. Demonstrated that reduction of pressure to 320 psig would not increase safety of existing pipeline, as ILI could no longer be done periodically at lower pressure. Commission accepted this reasoning and denied SDG&E's application.

Cove Point LNG Export Terminal. Expert witness in two separate administrative proceedings before the Maryland Public Service Commission, in 2014 and 2017, regarding air permit conditions for the proposed Cove Point LNG export. The plant site is located in a non-attainment area for ozone. Testimony addressed deficiencies in the proposed air emission limits and proposed control technology for combustion equipment – including gas turbines, auxiliary boilers, and flares, fugitive emission sources, and marine loading vapor recovery systems.

Corpus Christi LNG Expert Terminal. Expert witness in Texas Commission on Environmental Quality contested air permit proceeding in 2013 before the State Office of Administrative Hearings. Testimony addressed deficiencies in the proposed control technology for compressor-drive gas turbines, flares, and fugitive emission sources, and marine loading vapor recovery systems.

DISTRIBUTED SOLAR PV SITING AND REGIONAL RENEWABLE ENERGY PLANNING

Roadmap to 100 Percent Local Solar by 2030 in the City of San Diego. Author of the May 2020 *Roadmap to 100 Percent Local Solar Build-Out by 2030 in the City of San Diego* strategic energy plan for San Diego. The *Roadmap* outlines a strategy to maximize the use of solar energy and battery storage in the City of San Diego (City) to provide 100 percent clean electricity to all San Diegans by 2030. The City's Climate Action Plan sets a mandatory target of 100 percent clean electricity by 2035. The *Roadmap* describes how the City can best deliver lower-cost electricity and provide local job growth by choosing local solar power paired with battery storage, complemented by smart energy efficiency and demand response programs, to reach 100 percent clean energy.

North Carolina Clean Path 2025 Plan. Author of the August 2017 *North Carolina Clean Path 2025* strategic energy plan for North Carolina. *NC Clean Path 2025* implements local solar power, battery storage, and energy efficiency measures to rapidly replace fossil fuel-generated electricity in the state. The plan is substantially less costly than the $40 billion expansion of natural gas infrastructure, nuclear power, and transmission infrastructure being planned for North Carolina. Implementation of *NC Clean Path 2025* would reduce power generated by coal- and natural gas-fired plants by about 60 percent by 2025, and 100 percent by 2030. All in-state coal-fired plants would be closed and gas-fired plants would be used only for backup supply. Existing transmission and distribution infrastructure would be maintained and not expanded.

Bay Area Smart Energy 2020 Plan. Author of the March 2012 *Bay Area Smart Energy 2020* strategic energy plan for the nine-county region surrounding San Francisco Bay. This plan uses the zero net energy building targets in the *California Energy Efficiency Strategic Plan* as a framework to achieve a 60 percent reduction in GHG emissions from Bay Area electricity usage, and a 50 percent reduction in peak demand for grid electricity, by 2020. The 2020 targets in the plan include: 25 percent of detached homes and 20 percent of commercial buildings achieving zero net energy, adding 200 MW of community-scale microgrid battery storage and 400 MW of utility-scale battery storage, reduction in air conditioner loads by 50 percent through air conditioner cycling and targeted incentive funds to assure highest efficiency replacement units, and cooling system modifications to increase power output from The Geysers geothermal production zone in Sonoma County.

Solar PV technology selection and siting for SDG&E Solar San Diego project. Served as PV technology expert in California Public Utilities Commission proceeding to define PV technology and sites to be used in San Diego Gas & Electric (SDG&E) $250 million "Solar San Diego" project. Recommendations included: 1) prioritize use of roof-mounted thin-film PV arrays similar to the SCE urban PV program to maximize the installed PV capacity, 2) avoid tracking ground-mounted PV arrays due to high cost and relative lack of available land in the urban/suburban core, 3) and incorporate limited storage in fixed rooftop PV arrays to maximizing output during peak demand periods. Suitable land next to SDG&E substations capable of supporting 5 to 40 MW of PV (each) was also identified by Powers Engineering as a component of this project.

Rooftop PV alternative to natural gas-fired peaking gas turbines, Chula Vista. Served as PV technology expert in California Energy Commission (CEC) proceeding regarding the application of MMC Energy to build a 100 MW peaking gas turbine power plant in Chula Vista. Presented testimony that 100 MW of PV arrays in the Chula Vista area could provide the same level of electrical reliability on hot summer days as an equivalent amount of peaking gas turbine capacity at approximately the same cost of energy. The final decision issued by the CEC in the case denied the application in part due to failure of the applicant or CEC staff to thoroughly evaluate the PV alternative to the proposed turbines.

San Diego Smart Energy 2020 Plan. Author of October 2007 *San Diego Smart Energy 2020*, an energy plan that focuses on meeting the San Diego region's electric energy needs through accelerated integration of renewable and non-renewable distributed generation, in the form of combined heat and power (CHP) systems and solar photovoltaic (PV) systems. PV would meet approximately 28 percent of the San Diego region's electric energy demand in 2020. Annual energy demand would drop 20 percent in 2020 relative to 2003 through use all cost-effective energy efficiency measures. Existing utility-scale gas-fired generation would continue to be utilized to provide power at night, during cloudy weather, and for grid reliability support.

COOLING SYSTEM CONVERSION AND POWER PLANT EMISSION CONTROL ASSESSMENTS

Closed-Cycle Cooling Alternative at California Nuclear Plant.
Lead engineer on review of Bechtel assessment of wedgewire screens and closed-cycle cooling for Diablo Canyon nuclear plant. Demonstrated that wedgewire screens were not likely to be effective in substantially reducing entrainment at the site, and that lower cost closed-cycle retrofit alternatives could be utilized to allow a "cost reasonable" cooling tower retrofit. Plume-abated back-to-back cooling towers located in secondary parking lots to the southeast of the turbine building were identified as the most cost-effective alternative.

Closed-Cycle Cooling Alternative at Florida Nuclear Plant.
Evaluated closed cycle cooling tower feasibility assessment for Turkey Point Nuclear Units 3 and 4. Closed-cycle cooling would replace the existing closed-cycle cooling canals. Wet cooling towers for Units 3 and 4 are feasible and could be operational within four years of submittal of applications for the necessary permits.

Utility Boilers – Conversion of Existing Once-Through Cooled Boilers to Wet Towers, Parallel Wet-Dry Cooling, or Dry Cooling. Provided expert testimony and preliminary design for the conversion of four natural gas and/or coal-fired utility boilers (Unit 4, 235 MW; Unit 3, 135 MW; Unit 2, 65 MW; and Unit 1,65 MW) from once-through river water cooling to wet cooling towers, parallel wet-dry cooling, and dry cooling. Major design constraints were available land for location of retrofit cooling systems and need to maintain maximum steam turbine backpressure at or below 5.5 inches mercury to match performance capabilities of existing equipment. Approach temperatures of 12 ^{o}F and 13 ^{o}F were used for the wet towers. SPX Cooling Technologies F-488 plume-abated wet cells with six feet of packing were used to achieve approach temperatures of 12 ^{o}F and 13 ^{o}F. Annual energy penalty of wet tower retrofit designs is approximately 1 percent. Parallel wet-dry or dry cooling was determined to be technically feasible for Unit 3 based on straightforward access to the Unit 3 surface condenser and available land adjacent to the boiler.

Utility Boiler – Assessment of Air Cooling and Integrated Gasification/Combined Cycle for Proposed 500 MW Coal-Fired Plant. Provided expert testimony on the performance of air-cooling and IGCC relative to the conventional closed-cycle wet cooled, supercritical pulverized coal boiler proposed by the applicant. Steam Pro™ coal-fired power plant design software was used to model the proposed plant and evaluate the impacts on performance of air cooling and plume-abated wet cooling. Results indicated that a conservatively designed air-cooled condenser could maintain rated power output at the design ambient temperature of 90 ^{o}F. The IGCC comparative analysis indicated that unit reliability comparable to a conventional pulverized coal unit could be achieved by including a spare gasifier in the IGCC design, and that the slightly higher capital cost of IGCC was offset by greater thermal efficiency and reduced water demand and air emissions.

Utility Boiler – Assessment of Closed-Cycle Cooling Retrofit Cost for 1,200 MW Oil-Fired Plant. Prepared an assessment of the cost and feasibility of a closed-cycle wet tower retrofit for the 1,200 MW Roseton Generating Station. Determined that the cost to retrofit the Roseton plant with plume-abated closed-cycle wet cooling was well established based on cooling tower retrofit studies performed by the original owner (Central Hudson Gas & Electric Corp.) and subsequent regulatory agency critique of the cost estimate. Also determined that elimination of redundant and/or excessive budgetary line items in owners cost estimate brings the closed-cycle retrofit in line with expected costs for comparable new or retrofit plume-abated cooling tower applications.

Nuclear Power Plant – Assessment of Closed-Cycle Cooling Retrofit Cost for 2,000 MW Plant. Prepared an assessment of the cost and feasibility of a closed-cycle wet tower retrofit for the 2,000 MW Indian Point Generating Station. Determined that the most appropriate arrangement for the hilly site would be an inline plume-abated wet tower instead of the round tower configuration analyzed by the owner. Use of the inline configuration would allow placement of the towers at numerous sites on the property with little or need for blasting of bedrock, greatly reducing the cost of the retrofit. Also proposed an alternative circulating cooling water piping configuration to avoid the extensive downtime projected by the owner for modifications to the existing discharge channel.

Power Plant Dry Cooling Symposium – Chair and Organizer. Chair and organizer of the first symposium held in the U.S. (May 2002) that focused exclusively on dry cooling technology for power plants. Sessions included basic principles of wet and dry cooling systems, performance capabilities of dry cooling systems, case studies of specific installations, and reasons why dry cooling is the predominant form of cooling specified in certain regions of North America (Massachusetts, Nevada, northern Mexico).

Ameren Missouri Coal Units – Causes of Opacity and Opacity Reduction Alternatives. Lead engineer to assess the root causes of opacity exceedances and evaluate potential alternatives to eliminate opacity violations from the Labadie, Meramec, and Rush Island power plants.

Utility Boilers – Evaluation of Correlation Between Opacity and PM_{10} Emissions at Coal-Fired Plant. Provided expert testimony on whether correlation existed between mass PM_{10} emissions and opacity during opacity excursions at large coal-fired boiler in Georgia. EPA and EPRI technical studies were reviewed to assess the correlation of opacity and mass emissions during opacity levels below and above 20 percent. A strong correlation between opacity and mass emissions was apparent at a sister plant at opacities less than 20 percent. The correlation suggests that the opacity monitor correlation underestimates mass emissions at opacities greater than 20 percent, but may continue to exhibit a good correlation for the component of mass emissions in the PM_{10} size range.

IGCC as BACT for Air Emissions from Proposed 960 MW Coal Plant. Presented testimony on IGCC as BACT for air emissions reduction from 960 MW coal plant. Applicant received air permit for a pulverized coal plant to be equipped with a baghouse, wet scrubber, and wet ESP for air emissions control. Use of IGCC technology at the emission rates permitted for two recently proposed U.S. IGCC projects, and demonstrated in practice at a Japanese IGCC plant firing Chinese bituminous coal, would substantially reduce potential emissions of NO_x, SO_2, and PM. The estimated control cost-effectiveness of substituting IGCC for pulverized coal technology in this case was approximately $3,000/ton.

Analysis of Proposed Air Emission Limits for 600 MW Pulverized Coal Plant. Project engineer tasked with evaluating sufficiency of air emissions limits and control technologies for proposed 600 MW coal plant Arkansas. Determined that the applicant had: 1) not properly identified SO_2, sulfuric acid mist, and PM BACT control levels for the plant, and 2) improperly utilized an incremental cost effectiveness analysis to justify air emission control levels that did not represent BACT.

Eight Pulverized Coal Fired 900 MW Boilers – IGCC Alternative with Air Cooling. Provided testimony on integrated gasification combined cycle (IGCC) as a fully commercial coal-burning alternative to the pulverized coal (PC) technology proposed by TXU for eight 900 MW boilers in East Texas, and East Texas as an ideal location for CO2 sequestration due to presence of mature oilfield CO2 enhanced oil recovery opportunities and a deep saline aquifer underlying the entire region. Also presented testimony on the major increase in regional consumptive water use that would be caused by the evaporative cooling towers proposed for use in the PC plants, and that consumptive water use could be lowered by using IGCC with evaporative cooling towers or by using air-cooled condensers with PC or IGCC technology. TXU ultimately dropped plans to build the eight PC plants as a condition of a corporate buy-out.

Utility Boilers – Retrofit of SCR and FGD to Existing Coal-Fired Units.
Expert witness in successful effort to compel an existing coal-fired power plant located in Massachusetts to meet an accelerated NO_x and SO_2 emission control system retrofit schedule. Plant owner argued the installation of advanced NO_x and SO_2 control systems would generate > 1 ton/year of ancillary emissions, such as sulfuric acid mist, and that under Massachusetts Dept. of Environmental Protection regulation ancillary emissions > 1 ton/year would require a BACT evaluation and a two-year extension to retrofit schedule. Successfully demonstrated that no ancillary emissions would be generated if the retrofit NO_x and SO_2 control systems were properly sized and optimized. Plant owner committed to accelerated compliance schedule in settlement agreement.

Utility Boilers – Retrofit of SCR to Existing Natural Gas-Fired Units.
Lead engineer in successful representation of interests of California coastal city to prevent weakening of an existing countywide utility boiler NO_x rule. Weakening of NO_x rule would have allowed a merchant utility boiler plant located in the city to operate without installing selective catalytic reduction (SCR) NO_x control systems. This project required numerous appearances before the county air pollution control hearing board to successfully defend the existing utility boiler NO_x rule.

Biomass Plant NO_x and CO Air Emissions Control Evaluation. Lead engineer for evaluation of available nitrogen oxide (NO_x) and carbon monoxide (CO) controls for a 45 MW Aspen Power biomass plant in Texas where proponent had identified selective non-catalytic reduction (SNCR) for NO_x and good combustion practices for CO as BACT. Identified the use of tail-end SCR for NO_x control at several operational U.S. biomass plants, and oxidation catalyst in use at two of these plants for CO and VOC control, as BACT for the proposed biomass plant. Administrative law judge concurred in decision that SCR and oxidation catalyst is BACT. Developer added SCR and oxidation catalyst to project in subsequent settlement agreement.

Biomass Plant Air Emissions Control Consulting. Lead expert on biomass air emissions control systems for landowners that will be impacted by a proposed 50 MW biomass to be built by the local East Texas power cooperative. Public utility agreed to meet current BACT for biomass plants in Texas, SCR for NO_x and oxidation catalyst for CO, in settlement agreement with local landowners.

Combined-Cycle Power Plant Startup and Shutdown Emissions. Lead engineer for analysis of air permit startup and shutdown emissions minimization for combined-cycle power plant proposed for the San Francisco Bay Area. Original equipment was specified for baseload operation prior to suspension of project in early 2000s. Operational profile described in revised air permit was load following with potential for daily start/stop. Recommended that either fast start turbine technology be employed to minimize start/stop emissions or that "demonstrated in practice" operational and control software modifications be employed to minimize startup/shutdown emissions.

NON-WIRES ALTERNATIVES TO TRANSMISSION LINES

Ameren Missouri Mark Twain 345 kV Transmission Line. Responsible for evaluating: 1) the expected peak load growth of Ameren Missouri (MO) in general and in Northeast MO specifically over the next decade, 2) the likelihood of wind projects moving forward in the Northeast MO over the next decade, 3) the feasibility and cost of reconductoring with high capacity composite conductors the three 161 kV line segments that would experience NERC violations if 450 to 500 MW of wind power was constructed in Northeast MO, and 4) the feasibility and cost-effectiveness of substituting local solar for wind power to allow Ameren MO to meet its 2021 Renewable Portfolio Standard (RPS) obligation without building the proposed 345 kV transmission line or upgrading the three existing 161 kV lines interconnecting at the Adair Substation.

American Transmission Corporation Badger-Coulee 345 kV Line. Responsible for evaluating: 1) the expected peak load growth of Wisconsin utilities over the next decade, and 2) the feasibility and cost-effectiveness of alternatives including load management, energy efficiency, local solar, biogas, and energy storage as viable no-wires alternatives to the proposed ATC Badger-Coulee 345 kV transmission line.

San Diego Gas & Electric Wood Pole to Steel Pole Replacement Project.
Lead engineer assessing need and alternatives to replacement of existing wooden 69 kV poles with larger steel 69 kV poles as a response to the fire hazard potential of wooden poles in rural, high fire risk areas. Wooden poles in good condition and not a source of fire ignition. Utility would continue to shut off power to customers during low humidity, high wind conditions. Prepared alternative, solar with batteries for the ~10,000 affected customer meters, to allow customers to ride-through high fire hazard preventive grid power shut-offs at far less cost than replacing wood poles with steel poles.

San Diego Gas & Electric 500 kV Sunrise Transmission Line.
Lead engineer assessing the validity of load growth forecasts used by the utility to justify the need for the 500 kV line, and for developing a no-wires alternative, net-metered solar power with some battery support, to meet the identified reliability need at little or no net cost to the utility customer base.

COMBUSTION EQUIPMENT PERMITTING, TESTING AND MONITORING

EPRI Gas Turbine Power Plant Permitting Documents – Co-Author.
Co-authored two Electric Power Research Institute (EPRI) gas turbine power plant siting documents. Responsibilities included chapter on state-of-the-art air emission control systems for simple-cycle and combined-cycle gas turbines, and authorship of sections on dry cooling and zero liquid discharge systems.

Air Permits for 50 MW Peaker Gas Turbines – Six Sites Throughout California.
Responsible for preparing all aspects of air permit applications for five 50 MW FT-8 simple-cycle turbine installations at sites around California in response to emergency request by California state government for additional peaking power. Units were designed to meet 2.0 ppm NO_x using standard temperature SCR and innovative dilution air system to maintain exhaust gas temperature within acceptable SCR range. Oxidation catalyst is also used to maintain CO below 6.0 ppm.

Kauai 27 MW Cogeneration Plant – Air Emission Control System Analysis. Project manager to evaluate technical feasibility of SCR for 27 MW naphtha-fired turbine with once-through heat recovery steam generator. Permit action was stalled due to questions of SCR feasibility. Extensive analysis of the performance of existing oil-fired turbines equipped with SCR, and bench-scale tests of SCR applied to naphtha-fired turbines, indicated that SCR would perform adequately. Urea was selected as the SCR reagent given the local availability of urea. Unit is first known application of urea-injected SCR on a naphtha-fired turbine.

Microturbines – Ronald Reagan Library, Ventura County, California.
Project manager and lead engineer or preparation of air permit applications for microturbines and standby boilers. The microturbines drive the heating and cooling system for the library. The microturbines are certified by the manufacturer to meet the 9 ppm NO_x emission limit for this equipment. Low-NO_x burners are BACT for the standby boilers.

Hospital Cogeneration Microturbines – South Coast Air Quality Management District.
Project manager and lead engineer for preparation of air permit application for three microturbines at hospital cogeneration plant installation. The draft Authority To Construct (ATC) for this project was obtained two weeks after submittal of the ATC application. 30-day public notification was required due to the proximity of the facility to nearby schools. The final ATC was issued two months after the application was submitted, including the 30-day public notification period.

Gas Turbine Cogeneration – South Coast Air Quality Management District. Project manager and lead engineer for preparation of air permit application for two 5.5 MW gas turbines in cogeneration configuration for county government center. The turbines are equipped with selective catalytic reduction (SCR) and oxidation catalyst to comply with SCAQMD BACT requirements. Aqueous urea is used as the SCR reagent to avoid trigger hazardous material storage requirements. The NO_x and CO continuous emissions monitoring systems are covered by a separate permit.

Peaker Gas Turbines – Evaluation of NO_x Control Options for Installations in San Diego County.
Lead engineer for evaluation of NO_x control options available for 1970s vintage simple-cycle gas turbines proposed for peaker sites in San Diego County. Dry low-NO_x (DLN) combustors, catalytic combustors, high-temperature SCR, and NO_x absorption/conversion ($SCONO_x$) were evaluated for each candidate turbine make/model. High-temperature SCR was selected as the NOx control option to meet a 5 ppm NO_x emission requirement.

Hospital Cogeneration Plant Gas Turbines – San Joaquin Valley Unified Air Pollution Control District.
Project manager and lead engineer for preparation of air permit application and Best Available Control Technology (BACT) evaluation for hospital cogeneration plant installation. The BACT included the review of DLN combustors, catalytic combustors, high-temperature SCR and $SCONO_x$. DLN combustion followed by high temperature SCR was selected as the NO_x control system for this installation. The high temperature SCR is located upstream of the heat recovery steam generator (HRSG) to allow the diversion of exhaust gas around the HRSG without compromising the effectiveness of the NO_x control system.

1,000 MW Coastal Combined-Cycle Power Plant – Feasibility of Dry Cooling.
Expert witness in on-going effort to require use of dry cooling on proposed 1,000 MW combined-cycle "repower" project at site of an existing 1,000 MW utility boiler plant. Project proponent argued that site was two small for properly sized air-cooled condenser (ACC) and that use of ACC would cause 12-month construction delay. Demonstrated that ACC could easily be located on the site by splitting total of up to 80 cells between two available locations at the site. Also demonstrated that an ACC optimized for low height and low noise would minimize or eliminate proponent claims of negative visual and noise impacts.

Industrial Cogeneration Plant Gas Turbines – Upgrade of Turbine Power Output.
Project manager and lead engineer for preparation of Best Available Control Technology (BACT) evaluation for proposed gas turbine upgrade. The BACT included the review of DLN combustors, catalytic combustors, high-, standard-, and low-temperature SCR, and $SCONO_x$. Successfully negotiated air permit that allowed facility to initially install DLN combustors and operate under a NO_x plantwide "cap." Within two major turbine overhauls, or approximately eight years, the NO_x emissions per turbine must be at or below the equivalent of 5 ppm. The 5 ppm NO_x target will be achieved through technological in-combustor NO_x control such as catalytic combustion, or SCR or SCR equivalent end-of-pipe NO_x control technologies if catalytic combustion is not available.

Gas Turbines – Modification of RATA Procedures for Time-Share CEM.
Project manager and lead engineer for the development of alternate CO continuous emission monitor (CEM) Relative Accuracy Test Audit (RATA) procedures for time-share CEM system serving three 7.9 MW turbines located in San Diego. Close interaction with San Diego APCD and EPA Region 9 engineers was required to

receive approval for the alternate CO RATA standard. The time-share CEM then passed the annual RATA without problems as a result of changes to some CEM hardware and the more flexible CO RATA standard.

Gas Turbines – Evaluation of NO_x Control Technology Performance. Lead engineer for performance review of dry low-NO_x combustors, catalytic combustors, high-, standard-, and low-temperature selective catalytic reduction (SCR), and NO_x absorption/conversion ($SCONO_x$). Major turbine manufacturers and major manufacturers of end-of-pipe NO_x control systems for gas turbines were contacted to determine current cost and performance of NO_x control systems. A comparison of 1993 to 1999 "$/kwh" and "$/ton" cost of these control systems was developed in the evaluation.

Lead engineer for evaluation for proposed combined cycle gas turbine NO_x and CO control systems. Project was in litigation over contract terms, and there was concern that the GE Frame 7FA turbine could not meet the 3 ppm NO_x permit limit using a conventional combustor with water injection followed by SCR. Operations personnel at GE Frame 7FA installatins around the country were interviewed, along with principal SCR vendors, to corroborate that the installation could continuously meet the 3 ppm NO_x limit.

Gas Turbines – Title V "Presumptively Approvable" Compliance Assurance Monitoring Protocol. Project manager and lead engineer for the development of a "presumptively approval" NO_x parametric emissions monitoring system (PEMS) protocol for industrial gas turbines. "Presumptively approvable" means that any gas turbine operator selecting this monitoring protocol can presume it is acceptable to the U.S. EPA. Close interaction with the gas turbine manufacturer's design engineering staff and the U.S. EPA Emissions Measurement Branch (Research Triangle Park, NC) was required to determine modifications necessary to the current PEMS to upgrade it to "presumptively approvable" status.

Environmental Due Diligence Review of Gas Turbine Sites – Mexico. Task leader to prepare regulatory compliance due diligence review of Mexican requirements for gas turbine power plants. Project involves eleven potential sites across Mexico, three of which are under construction. Scope involves identification of all environmental, energy sales, land use, and transportation corridor requirements for power projects in Mexico. Coordinator of Mexican environmental subcontractors gathering on-site information for each site, and translator of Spanish supporting documentation to English.

Development of Air Emission Standards for Gas Turbines - Peru. Served as principal technical consultant to the Peruvian Ministry of Energy in Mines (MEM) for the development of air emission standards for Peruvian gas turbine power plants. All major gas turbine power plants in Peru are currently using water injection to increase turbine power output. Recommended that 42 ppm on natural gas and 65 ppm on diesel (corrected to 15% O_2) be established as the NO_x limit for existing gas turbine power plants. These limits reflect NO_x levels readily achievable using water injection at high load. Also recommended that new gas turbine sources be subject to a BACT review requirement.

Gas Turbines – Title V Permit Templates. Lead engineer for the development of standardized permit templates for approximately 100 gas turbines operated by the oil and gas industry in the San Joaquin Valley. Emissions limits and monitoring requirements were defined for units ranging from GE Frame 7 to Solar Saturn turbines. Stand-alone templates were developed based on turbine size and NO_x control equipment. NO_x utilized in the target turbine population ranged from water injection alone to water injection combined with SCR.

Gas Turbines – Evaluation of NO_x, SO_2 and PM Emission Profiles. Performed a comparative evaluation of the NO_x, SO_2 and particulate (PM) emission profiles of principal utility-scale gas turbines for an independent power producer evaluating project opportunities in Latin America. All gas turbine models in the 40 MW to 240 MW range manufactured by General Electric, Westinghouse, Siemens and ABB were included in the evaluation.

Stationary Internal Combustion Engine (ICE) RACT/BARCT Evaluation. Lead engineer for evaluation of retrofit NO_x control options available for the oil and gas production industry gas-fired ICE population in the San Joaquin Valley affected by proposed RACT and BARCT emission limits. Evaluation centered on lean-burn compressor engines under 500 bhp, and rich-burn constant and cyclically loaded (rod pump) engines under 200 bhp. The results of the evaluation indicated that rich burn cyclically-loaded rod pump engines comprised 50 percent of the affected ICE population, though these ICEs accounted for only 5 percent of the uncontrolled gas-fired stationary ICE NO_x emissions. Recommended retrofit NO_x control strategies included: air/fuel ratio adjustment for rod pump ICEs, Non-selective catalytic reduction (NSCR) for rich-burn, constant load ICEs, and "low emission" combustion modifications for lean burn ICEs.

Development of Air Emission Standards for Stationary ICEs - Peru. Served as principal technical consultant to the Peruvian Ministry of Energy in Mines (MEM) for the development of air emission standards for Peruvian stationary ICE power plants. Draft 1997 World Bank NO_x and particulate emission limits for stationary ICE power plants served as the basis for proposed MEM emission limits. A detailed review of ICE emissions data provided in PAMAs submitted to the MEM was performed to determine the level of effort that would be required by Peruvian industry to meet the proposed NO_x and particulate emission limits. The draft 1997 WB emission limits were revised to reflect reasonably achievable NO_x and particulate emission limits for ICEs currently in operation in Peru.

Air Toxics Testing of Natural Gas-Fired ICEs. Project manager for test plan/test program to measure volatile and semi-volatile organic air toxics compounds from fourteen gas-fired ICEs used in a variety of oil and gas production applications. Test data was utilized by oil and gas production facility owners throughout California to develop accurate ICE air toxics emission inventories.

AIR ENGINEERING/AIR TESTING PROJECT EXPERIENCE – GENERAL

Reverse Air Fabric Filter Retrofit Evaluation – Coal-Fired Boiler. Lead engineer for upgrade of reverse air fabric filters serving coal-fired industrial boilers. Fluorescent dye injected to pinpoint broken bags and damper leaks. Corrosion of pneumatic actuators serving reverse air valves and inadequate insulation identified as principal causes of degraded performance.

Pulse-Jet Fabric Filter Performance Evaluation – Gold Mine. Lead engineer on upgrade of pulse-jet fabric filter and associated exhaust ventilation system serving an ore-crushing facility at a gold mine. Fluorescent dye used to identify bag collar leaks, and modifications were made to pulse air cycle time and duration. This marginal source was in compliance at 20 percent of emission limit following completion of repair work.

Pulse-Jet Fabric Filter Retrofit - Gypsum Calciner. Lead engineer on upgrade of pulse-jet fabric filter controlling particulate emissions from a gypsum calciner. Recommendations included a modified bag clamping mechanism, modified hopper evacuation valve assembly, and changes to pulse air cycle time and pulse duration.

Wet Scrubber Retrofit – Plating Shop. Project engineer on retrofit evaluation of plating shop packed-bed wet scrubbers failing to meet performance guarantees during acceptance trials, due to excessive mist carryover. Recommendations included relocation of the mist eliminator (ME), substitution of the original chevron blade ME with a mesh pad ME, and use of higher density packing material to improve exhaust gas distribution. Wet scrubbers passed acceptance trials following completion of recommended modifications.

Electrostatic Precipitator (ESP) Retrofit Evaluation – MSW Boiler. Lead engineer for retrofit evaluation of single field ESP on a municipal solid waste (MSW) boiler. Recommendations included addition of automated power controller, inlet duct turning vanes, and improved collecting plate rapping system.

ESP Electric Coil Rapper Vibration Analysis Testing - Coal-Fired Boiler. Lead engineer for evaluation of ESP rapper effectiveness test program on three field ESP equipped with "magnetically induced gravity return" (MIGR) rappers. Accelerometers were placed in a grid pattern on ESP collecting plates to determine maximum

instantaneous plate acceleration at a variety of rapper power setpoints. Testing showed that the rappers met performance specification requirements.

Aluminum Remelt Furnace Particulate Emissions Testing. Project manager and lead engineer for high temperature (1,600 ºF) particulate sampling of a natural gas-fired remelt furnace at a major aluminum rolling mill. Objectives of test program were to: 1) determine if condensable particulate was present in stack gases, and 2) to validate the accuracy of the in-stack continuous opacity monitor (COM). Designed and constructed a customized high temperature (inconel) PM_{10}/Mtd 17 sampling assembly for test program. An onsite natural gas-fired boiler was also tested to provide comparative data for the condensable particulate portion of the test program. Test results showed that no significant levels of condensable particulate in the remelt furnace exhaust gas, and indicated that the remelt furnace and boiler had similar particulate emission rates. Test results also showed that the COM was accurate.

Aluminum Remelt Furnace CO and NO_x Testing. Project manager and lead engineer for continuous week-long testing of CO and NO_x emissions from aluminum remelt furnace. Objective of test program was to characterize CO and NO_x emissions from representative remelt furnace for use in the facility's criteria pollution emissions inventory. A TECO Model 48 CO analyzer and a TECO Model 10 NO_x analyzer were utilized during the test program to provide $\pm$1 ppm measurement accuracy, and all test data was recorded by an automated data acquisition system.

PETROLEUM REFINERY AIR ENGINEERING/TESTING EXPERIENCE

Big West Refinery Expansion EIS. Lead engineer on comparative cost analysis of proposed wet cooling tower and fin-fan air cooler for process cooling water for the proposed clean fuels expansion project at the Big West Refinery in Bakersfield, California. Selection of the fin-fin air-cooler would eliminate all consumptive water use and wastewater disposal associated with the cooling tower. Air emissions of VOC and PM_{10} would be reduced with the fin-fan air-cooler even though power demand of the air-cooler is incrementally higher than that of the cooling tower. Fin-fan air-coolers with approach temperatures of 10 ºF and 20 ºF were evaluated. The annualized cost of the fin-fin air-cooler with a 20 ºF approach temperature is essentially the same as that of the cooling tower when the cost of all ancillary cooling tower systems are considered.

Criteria and Air Toxic Pollutant Emissions Inventory for Proposed Refinery Modifications. Project manager and technical lead for development of baseline and future refinery air emissions inventories for process modifications required to produce oxygenated gasoline and desulfurized diesel fuel at a California refinery. State of the art criteria and air toxic pollutant emissions inventories for refinery point, fugitive and mobile sources were developed. Point source emissions estimates were generated using onsite criteria pollutant test data, onsite air toxics test data, and the latest air toxics emission factors from the statewide refinery air toxics inventory database. The fugitive volatile organic compound (VOC) emissions inventories were developed using the refinery's most recent inspection and maintenance (I&M) monitoring program test data to develop site-specific component VOC emission rates. These VOC emission rates were combined with speciated air toxics test results for the principal refinery process streams to produce fugitive VOC air toxics emission rates. The environmental impact report (EIR) that utilized this emission inventory data was the first refinery "Clean Fuels" EIR approved in California.

Development of Air Emission Standards for Petroleum Refinery Equipment - Peru. Served as principal technical consultant to the Peruvian Ministry of Energy in Mines (MEM) for the development of air emission standards for Peruvian petroleum refineries. The sources included in the scope of this project included: 1) SO_2 and NO_x refinery heaters and boilers, 2) desulfurization of crude oil, particulate and SO_2 controls for fluid catalytic cracking units (FCCU), 3) VOC and CO emissions from flares, 4) vapor recovery systems for marine unloading, truck loading, and crude oil/refined products storage tanks, and 5) VOC emissions from process fugitive sources such as pressure relief valves, pumps, compressors and flanges. Proposed emission limits were developed for new and existing refineries based on a thorough evaluation of the available air emission control technologies for the affected refinery sources. Leading vendors of refinery control technology, such as John Zink and Exxon Research, provided estimates of retrofit costs for the largest Peruvian refinery, La Pampilla,

located in Lima. Meetings were held in Lima with refinery operators and MEM staff to discuss the proposed emission limits and incorporate mutually agreed upon revisions to the proposed limits for existing Peruvian refineries.

Air Toxic Pollutant Emissions Inventory for Existing Refinery. Project manager and technical lead for air toxic pollutant emissions inventory at major California refinery. Emission factors were developed for refinery heaters, boilers, flares, sulfur recovery units, coker deheading, IC engines, storage tanks, process fugitives, and catalyst regeneration units. Onsite source test results were utilized to characterize emissions from refinery combustion devices. Where representative source test results were not available, AP-42 VOC emission factors were combined with available VOC air toxics speciation profiles to estimate VOC air toxic emission rates. A risk assessment based on this emissions inventory indicated a relatively low health risk associated with refinery operations. Benzene, 1,3-butadiene and PAHs were the principal health risk related pollutants emitted.

Air Toxics Testing of Refinery Combustion Sources. Project manager for comprehensive air toxics testing program at a major California refinery. Metals, Cr^{+6}, PAHs, H_2S and speciated VOC emissions were measured from refinery combustion sources. High temperature Cr^{+6} stack testing using the EPA Cr^{+6} test method was performed for the first time in California during this test program. Representatives from the California Air Resources Board source test team performed simultaneous testing using ARB Method 425 (Cr^{+6}) to compare the results of EPA and ARB Cr^{+6} test methodologies. The ARB approved the test results generated using the high temperature EPA Cr^{+6} test method.

Air Toxics Testing of Refinery Fugitive Sources. Project manager for test program to characterize air toxic fugitive VOC emissions from fifteen distinct process units at major California refinery. Gas, light liquid, and heavy liquid process streams were sampled. BTXE, 1,3-butadiene and propylene concentrations were quantified in gas samples, while BTXE, cresol and phenol concentrations were measured in liquid samples. Test results were combined with AP-42 fugitive VOC emission factors for valves, fittings, compressors, pumps and PRVs to calculate fugitive air toxics VOC emission rates.

OIL AND GAS PRODUCTION AIR ENGINEERING/TESTING EXPERIENCE

Air Toxics Testing of Oil and Gas Production Sources. Project manager and lead engineer for test plan/test program to determine VOC removal efficiency of packed tower scrubber controlling sulfur dioxide emissions from a crude oil-fired steam generator. Ratfisch 55 VOC analyzers were used to measure the packed tower scrubber VOC removal efficiency. Tedlar bag samples were collected simultaneously to correlate BTX removal efficiency to VOC removal efficiency. This test was one of hundreds of air toxics tests performed during this test program for oil and gas production facilities from 1990 to 1992. The majority of the volatile air toxics analyses were performed at in-house laboratory. Project staff developed thorough familiarity with the applications and limitations of GC/MS, GC/PID, GC/FID, GC/ECD and GC/FPD. Tedlar bags, canisters, sorbent tubes and impingers were used during sampling, along with isokinetic tests methods for multiple metals and PAHs.

Air Toxics Testing of Glycol Reboiler – Gas Processing Plant. Project manager for test program to determine emissions of BTXE from glycol reboiler vent at gas processing facility handling 12 MM/cfd of produced gas. Developed innovative test methods to accurately quantify BTXE emissions in reboiler vent gas.
Air Toxics Emissions Inventory Plan. Lead engineer for the development of generic air toxics emission estimating techniques (EETs) for oil and gas production equipment. This project was performed for the Western States Petroleum Association in response to the requirements of the California Air Toxics "Hot Spots" Act. EETs were developed for all point and fugitive oil and gas production sources of air toxics, and the specific air toxics associated with each source were identified. A pooled source emission test methodology was also developed to moderate the cost of source testing required by the Act.

Fugitive NMHC Emissions from TEOR Production Field. Project manager for the quantification of fugitive Nonmethane hydrocarbon (NMHC) emissions from a thermally enhanced oil recovery (TEOR) oil production field in Kern County, CA. This program included direct measurement of NMHC concentrations in storage tank

vapor headspace and the modification of available NMHC emission factors for NMHC-emitting devices in TEOR produced gas service, such as wellheads, vapor trunklines, heat exchangers, and compressors. Modification of the existing NMHC emission factors was necessary due to the high concentration of CO_2 and water vapor in TEOR produced gases.

Fugitive Air Emissions Testing of Oil and Gas Production Fields. Project manager for test plan/test program to determine VOC and air toxics emissions from oil storage tanks, wastewater storage tanks and produced gas lines. Test results were utilized to develop comprehensive air toxics emissions inventories for oil and gas production companies participating in the test program.

Oil and Gas Production Field – Air Emissions Inventory and Air Modeling. Project manager for oil and gas production field risk assessment. Project included review and revision of the existing air toxics emission inventory, air dispersion modeling, and calculation of the acute health risk, chronic non-carcinogenic risk and carcinogenic risk of facility operations. Results indicated that fugitive H_2S emissions from facility operations posed a potential health risk at the facility fenceline.

TITLE V PERMIT APPLICATION/MONITORING PLAN EXPERIENCE

Title V Permit Application – San Diego County Industrial Facility. Project engineer tasked with preparing streamlined Title V operating permit for U.S. Navy facilities in San Diego. Principal emission units included chrome plating, lead furnaces, IC engines, solvent usage, aerospace coating and marine coating operations. For each device category in use at the facility, federal MACT requirements were integrated with District requirements in user friendly tables that summarized permit conditions and compliance status.

Title V Permit Application Device Templates - Oil and Gas Production Industry. Project manager and lead engineer to prepare Title V permit application "templates" for the Western States Petroleum Association (WSPA). The template approach was chosen by WSPA to minimize the administrative burden associated with listing permit conditions for a large number of similar devices located at the same oil and gas production facility. Templates are being developed for device types common to oil and gas production operations. Device types include: boilers, steam generators, process heaters, gas turbines, IC engines, fixed-roof storage tanks, fugitive components, flares, and cooling towers. These templates will serve as the core of Title V permit applications prepared for oil and gas production operations in California.

Title V Permit Application - Aluminum Rolling Mill. Project manager and lead engineer for Title V permit application prepared for largest aluminum rolling mill in the western U.S. Responsible for the overall direction of the permit application project, development of a monitoring plan for significant emission units, and development of a hazardous air pollutant (HAP) emissions inventory. The project involved extensive onsite data gathering, frequent interaction with the plant's technical and operating staff, and coordination with legal counsel and subcontractors. The permit application was completed on time and in budget.

Title V Model Permit - Oil and Gas Production Industry. Project manager and lead engineer for the comparative analysis of regional and federal requirements affecting oil and gas production industry sources located in the San Joaquin Valley. Sources included gas turbines, IC engines, steam generators, storage tanks, and process fugitives. From this analysis, a model applicable requirements table was developed for a sample device type (storage tanks) that covered the entire population of storage tanks operated by the industry. The U.S. EPA has tentatively approved this model permit approach, and work is ongoing to develop comprehensive applicable requirements tables for each major category of sources operated by the oil and gas industry in the San Joaquin Valley.

Title V Enhanced Monitoring Evaluation of Oil and Gas Production Sources. Lead engineer to identify differences in proposed EPA Title V enhanced monitoring protocols and the current monitoring requirements for oil and gas production sources in the San Joaquin Valley. The device types evaluated included: steam generators, stationary ICEs, gas turbines, fugitives, fixed roof storage tanks, and thermally enhanced oil recovery (TEOR) well vents. Principal areas of difference included: more stringent Title V O&M requirements

for parameter monitors (such as temperature, fuel flow, and O_2), and more extensive Title V recordkeeping requirements.

RACT/BARCT/BACT EVALUATIONS

RACT/BARCT Reverse Jet Scrubber/Fiberbed Mist Eliminator Retrofit Evaluation. Project manager and lead engineer on project to address the inability of existing wet electrostatic precipitators (ESPs) and atomized mist scrubbers to adequately remove low concentration submicron particulate from high volume recovery boiler exhaust gas at the Alaska Pulp Corporation mill in Sitka, AK. The project involved thorough on-site inspections of existing control equipment, detailed review of maintenance and performance records, and a detailed evaluation of potential replacement technologies. These technologies included a wide variety of scrubbing technologies where manufacturers claimed high removal efficiencies on submicron particulate in high humidity exhaust gas. Packed tower scrubbers, venturi scrubbers, reverse jet scrubbers, fiberbed mist eliminators and wet ESPs were evaluated. Final recommendations included replacement of atomized mist scrubber with reverse jet scrubber and upgrading of the existing wet ESPs. The paper describing this project was published in the May 1992 TAPPI Journal.

Aluminum Smelter RACT Evaluation - Prebake. Project manager and technical lead for CO and PM_{10} RACT evaluation for prebake facility. Retrofit control options for CO emissions from the anode bake furnace, potline dry scrubbers and the potroom roof vents were evaluated. PM_{10} emissions from the coke kiln, potline dry scrubbers, potroom roof vents, and miscellaneous potroom fugitive sources were addressed. Four CO control technologies were identified as technologically feasible for potline CO emissions: potline current efficiency improvement through the addition of underhung busswork and automated puncher/feeders, catalytic incineration, recuperative incineration and regenerative incineration. Current efficiency improvement was identified as probable CO RACT if onsite test program demonstrated the effectiveness of this approach. Five PM_{10} control technologies were identified as technologically feasible: increased potline hooding efficiency through redesign of shields, the addition of a dense-phase conveying system, increased potline air evacuation rate, wet scrubbing of roof vent emissions, and fabric filter control of roof vent emissions.

RACT/BACT Testing/Evaluation of PM_{10} Mist Eliminators on Five-Stand Cold Mill. Project manager and lead engineer for fiberbed mist eliminator and mesh pad mist eliminator comparative pilot test program on mixed phase aerosol (PM_{10})/gaseous hydrocarbon emissions from aluminum high speed cold rolling mill. Utilized modified EPA Method 5 sampling train with portion of sample gas diverted (after particulate filter) to Ratfisch 55 VOC analyzer. This was done to permit simultaneous quantification of aerosol and gaseous hydrocarbon emissions in the exhaust gas. The mesh pad mist eliminator demonstrated good control of PM_{10} emissions, though test results indicated that the majority of captured PM_{10} evaporated in the mesh pad and was emitted as VOC.

Aluminum Remelt Furnace/Rolling Mill RACT Evaluations. Lead engineer for comprehensive CO and PM_{10} RACT evaluation for the largest aluminum sheet and plate rolling mill in western U.S. Significant sources of CO emissions from the facility included the remelt furnaces and the coater line. The potential CO RACT options for the remelt furnaces included: enhanced maintenance practices, preheating combustion air, installation of fully automated combustion controls, and energy efficiency modifications.

BARCT Low NO_x Burner Conversion – Industrial Boilers. Lead engineer for evaluation of low NO_x burner options for natural gas-fired industrial boilers. Also evaluated methanol and propane as stand-by fuels to replace existing diesel stand-by fuel system. Evaluated replacement of steam boilers with gas turbine co-generation system.

BACT Packed Tower Scrubber/Mist Eliminator Performance Evaluations. Project manager and lead engineer for Navy-wide plating shop air pollution control technology evaluation and emissions testing program. Mist eliminators and packed tower scrubbers controlling metal plating processes, which included hard chrome, nickel, copper, cadmium and precious metals plating, were extensively tested at three Navy plating shops.

Chemical cleaning and stripping tanks, including hydrochloric acid, sulfuric acid, chromic acid and caustic, were also tested. The final product of this program was a military design specification for plating and chemical cleaning shop air pollution control systems. The hydrochloric acid mist sampling procedure developed during this program received a protected patent.

BACT Packed Tower Scrubber/UV Oxidation System Pilot Test Program. Technical advisor for pilot test program of packed tower scrubber/ultraviolet (UV) light VOC oxidation system controlling VOC emissions from microchip manufacturing facility in Los Angeles. The testing was sponsored in part by the SCAQMD's Innovative Technology Demonstration Program, to demonstrate this innovative control technology as BACT for microchip manufacturing operations. The target compounds were acetone, methylethylketone (MEK) and 1,1,1-trichloroethane, and compound concentrations ranged from 10-100 ppmv. The single stage packed tower scrubber consistently achieved greater than 90% removal efficiency on the target compounds. The residence time required in the UV oxidation system for effective oxidation of the target compounds proved significantly longer than the residence time predicted by the manufacturer.

BACT Pilot Testing of Venturi Scrubber on Gas/Aerosol VOC Emission Source. Technical advisor for project to evaluate venturi scrubber as BACT for mixed phase aerosol/gaseous hydrocarbon emissions from deep fat fryer. Venturi scrubber demonstrated high removal efficiency on aerosol, low efficiency on VOC emissions. A number of VOC tests indicated negative removal efficiency. This anomaly was traced to a high hydrocarbon concentration in the scrubber water. The pilot unit had been shipped directly to the jobsite from another test location by the manufacturer without any cleaning or inspection of the pilot unit.

Pulp Mill Recovery Boiler BACT Evaluation. Lead engineer for BACT analysis for control of SO_2, NO_x, CO, TNMHC, TRS and particulate emissions from the proposed addition of a new recovery furnace at a kraft pulp mill in Washington. A "top down" approach was used to evaluate potential control technologies for each of the pollutants considered in the evaluation.

Air Pollution Control Equipment Design Specification Development. Lead engineer for the development of detailed Navy design specifications for wet scrubbers and mist eliminators. Design specifications were based on field performance evaluations conducted at the Long Beach Naval Shipyard, Norfolk Naval Shipyard, and Jacksonville Naval Air Station. This work was performed for the U.S. Navy to provide generic design specifications to assist naval facility engineering divisions with air pollution control equipment selection. Also served as project engineer for the development of Navy design specifications for ESPs and fabric filters.

CONTINUOUS EMISSION MONITOR (CEM) PROJECT EXPERIENCE

Process Heater CO and NO_x CEM Relative Accuracy Testing. Project manager and lead engineer for process heater CO and NO_x analyzer relative accuracy test program at petrochemical manufacturing facility. Objective of test program was to demonstrate that performance of onsite CO and NO_x CEMs was in compliance with U.S. EPA "Boiler and Industrial Furnace" hazardous waste co-firing regulations. A TECO Model 48 CO analyzer and a TECO Model 10 NO_x analyzer were utilized during the test program to provide $\pm$1 ppm measurement accuracy, and all test data was recorded by an automated data acquisition system. One of the two process heater CEM systems tested failed the initial test due to leaks in the gas conditioning system. Troubleshooting was performed using O_2 analyzers, and the leaking component was identified and replaced. This CEM system met all CEM relative accuracy requirements during the subsequent retest.

Performance Audit of NO_x and SO_2 CEMs at Coal-Fired Power Plant. Lead engineer on system audit and challenge gas performance audit of NO_x and SO_2 CEMs at a coal-fired power plant in southern Nevada. Dynamic and instrument calibration checks were performed on the CEMs. A detailed visual inspection of the CEM system, from the gas sampling probes at the stack to the CEM sample gas outlet tubing in the CEM trailer, was also conducted. The CEMs passed the dynamic and instrument calibration requirements specified in EPA's Performance Specification Test - 2 (NO_x and SO_2) alternative relative accuracy requirements.

LATIN AMERICA ENVIRONMENTAL PROJECT EXPERIENCE

Assessment of operational deficiencies of Camisa pipeline – Peru. Project leader of multi-year assessment of root causes of ruptures on Camisea 14-inch natural gas liquids pipeline for non-profit client. Determined that primary causes of hurried construction in difficult and unstable terrain, unstable right-of-way in the jungle sector due to inadequate erosion control practices, and inadequate pipe wall thickness to withstand external lateral forces. Two assessments were developed during the course of the project documenting deficiencies and recommending remedial actions.

Evaluation of U.S.-Mexico Border Region Copper Smelter Compliance with Treaty Obligations – Mexico. Project manager and lead engineer to evaluate compliance of U.S. and Mexican border region copper smelters with the SO_2 monitoring, recordkeeping and reporting requirements in Annex IV [Copper Smelters] of the La Paz Environmental Treaty. Identified potential problems with current ambient and stack monitoring practices that could result in underestimating the impact of SO_2 emissions from some of these copper smelters. Identified additional source types, including hazardous waste incinerators and power plants, that should be considered for inclusion in the La Paz Treaty process.

Development of Air Emission Limits for ICE Cogeneration Plant - Panamá. Lead engineer assisting U.S. cogeneration plant developer to permit an ICE cogeneration plant at a hotel/casino complex in Panama. Recommended the use of modified draft World Bank NO_x and PM limits for ICE power plants. The modification consisted of adding a thermal efficiency factor adjustment to the draft World Bank NO_x and PM limits. These proposed ICE emission limits are currently being reviewed by Panamanian environmental authorities.

Mercury Emissions Inventory for Stationary Sources in Northern Mexico. Project manager and lead engineer to estimate mercury emissions from stationary sources in Northern Mexico. Major potential sources of mercury emissions include solid- and liquid-fueled power plants, cement kilns co-firing hazardous waste, and non-ferrous metal smelters. Emission estimates were provided for approximately eighty of these sources located in Northern Mexico. Coordinated efforts of two Mexican subcontractors, located in Mexico City and Hermosillo, to obtain process throughput data for each source included in the inventory.

Translation of U.S. EPA Scrap Tire Combustion Emissions Estimation Document – Mexico. Evaluated the Translated a U.S. EPA scrap tire combustion emissions estimation document from English to Spanish for use by Latin American environmental professionals.

Environmental Audit of Aluminum Production Facilities – Venezuela. Evaluated the capabilities of existing air, wastewater and solid/hazardous waste control systems used by the aluminum industry in eastern Venezuela. This industry will be privatized in the near future. Estimated the cost to bring these control systems into compliance with air, wastewater and solid/hazardous waste standards recently promulgated in Venezuela. Also served as technical translator for team of U.S. environmental engineers involved in the due diligence assessment.

Assessment of Environmental Improvement Projects – Chile and Peru. Evaluated potential air, water, soil remediation and waste recycling projects in Lima, Peru and Santiago, Chile for feasibility study funding by the U.S. Trade and Development Agency. Project required onsite interaction with in-country decisionmakers (in Spanish). Projects recommended for feasibility study funding included: 1) an air quality technical support project for the Santiago, Chile region, and 2) soil remediation/metals recovery projects at two copper mine/smelter sites in Peru.

Air Pollution Control Training Course – Mexico. Conducted two-day Spanish language air quality training course for environmental managers of assembly plants in Mexicali, Mexico. Spanish-language course manual prepared by Powers Engineering. Practical laboratory included training in use of combustion gas analyzer, flame ionization detector (FID), photoionization detector (PID), and occupational sampling.

Stationary Source Emissions Inventory – Mexico. Developed a comprehensive air emissions inventory for stationary sources in Nogales, Sonora. This project requires frequent interaction with Mexican state and federal environmental authorities. The principal Powers Engineering subcontractor on this project is a Mexican firm located in Hermosillo, Sonora.

VOC Measurement Program – Mexico. Performed a comprehensive volatile organic compound (VOC) measurements program at a health products fabrication plant in Mexicali, Mexico. An FID and PID were used to quantify VOCs from five processes at the facility. Occupational exposures were also measured. Worker exposure levels were above allowable levels at several points in the main assembly area.

Fluent in Spanish. Studied at the Universidad de Michoacán in Morelia, Mexico, 1993, and at the Colegio de España in Salamanca, Spain, 1987-88. Have lectured (in Spanish) on air monitoring and control equipment at the Instituto Tecnológico de Tijuana. Maintain contact with Comisión Federal de Electricidad engineers responsible for operation of wind and geothermal power plants in Mexico, and am comfortable operating in the Mexican business environment.

PUBLICATIONS

Bill Powers, "*More Distributed Solar Means Fewer New Combustion Turbines*," Natural Gas & Electricity Journal, Vol. 29, Number 2, September 2012, pp. 17-20.

Bill Powers, "*Federal Government Betting on Wrong Solar Horse*," Natural Gas & Electricity Journal, Vol. 27, Number 5, December 2010,

Bill Powers, "*Today's California Renewable Energy Strategy—Maximize Complexity and Expense*," Natural Gas & Electricity Journal, Vol. 27, Number 2, September 2010, pp. 19-26.

Bill Powers, "*Environmental Problem Solving Itself Rapidly Through Lower Gas Costs*," Natural Gas & Electricity Journal, Vol. 26, Number 4, November 2009, pp. 9-14.

Bill Powers, "*PV Pulling Ahead, but Why Pay Transmission Costs?*" Natural Gas & Electricity Journal, Vol. 26, Number 3, October 2009, pp. 19-22.

Bill Powers, "*Unused Turbines, Ample Gas Supply, and PV to Solve RPS Issues*," Natural Gas & Electricity Journal, Vol. 26, Number 2, September 2009, pp. 1-7.

Bill Powers, "*CEC Cancels Gas-Fed Peaker, Suggesting Rooftop Photovoltaic Equally Cost-Effective*," Natural Gas & Electricity Journal, Vol. 26, Number 1, August 2009, pp. 8-13.

Bill Powers, "*San Diego Smart Energy 2020 – The 21st Century Alternative*," San Diego, October 2007.

Bill Powers, "*Energy, the Environment, and the California – Baja California Border Region*," Electricity Journal, Vol. 18, Issue 6, July 2005, pp. 77-84.

W.E. Powers, *"Peak and Annual Average Energy Efficiency Penalty of Optimized Air-Cooled Condenser on 515 MW Fossil Fuel-Fired Utility Boiler,"* presented at California Energy Commission/Electric Power Research Institute Advanced Cooling Technologies Symposium, Sacramento, California, June 2005.

W.E. Powers, R. Wydrum, P. Morris, *"Design and Performance of Optimized Air-Cooled Condenser at Crockett Cogeneration Plant,"* presented at EPA Symposium on Technologies for Protecting Aquatic Organisms from Cooling Water Intake Structures, Washington, DC, May 2003.

P. Pai, D. Niemi, W.E. Powers, *"A North American Anthropogenic Inventory of Mercury Emissions,"* presented at Air & Waste Management Association Annual Conference in Salt Lake City, UT, June 2000.

P.J. Blau and W.E. Powers, *"Control of Hazardous Air Emissions from Secondary Aluminum Casting Furnace Operations Through a Combination of: Upstream Pollution Prevention Measures, Process Modifications and End-of-Pipe Controls,"* presented at 1997 AWMA/EPA Emerging Solutions to VOC & Air Toxics Control Conference, San Diego, CA, February 1997.

W.E. Powers, et. al., *"Hazardous Air Pollutant Emission Inventory for Stationary Sources in Nogales, Sonora, Mexico ,"* presented at 1995 AWMA/EPA Emissions Inventory Specialty Conference, RTP, NC, October 1995.

W.E. Powers, *"Develop of a Parametric Emissions Monitoring System to Predict NO_x Emissions from Industrial Gas Turbines,"* presented at 1995 AWMA Golden West Chapter Air Pollution Control Specialty Conference, Ventura, California, March 1995.

W. E. Powers, et. al., *"Retrofit Control Options for Particulate Emissions from Magnesium Sulfite Recovery Boilers,"* presented at 1992 TAPPI Envr. Conference, April 1992. Published in *TAPPI Journal*, July 1992.

S. S. Parmar, M. Short, W. E. Powers, *"Determination of Total Gaseous Hydrocarbon Emissions from an Aluminum Rolling Mill Using Methods 25, 25A, and an Oxidation Technique,"* presented at U.S. EPA Measurement of Toxic and Related Air Pollutants Conference, May 1992.

N. Meeks, W. E. Powers, *"Air Toxics Emissions from Gas-Fired Internal Combustion Engines,"* presented at AIChE Summer Meeting, August 1990.

W. E. Powers, *"Air Pollution Control of Plating Shop Processes,"* presented at 7th AES/EPA Conference on Pollution Control in the Electroplating Industry, January 1986. Published in *Plating and Surface Finishing* magazine, July 1986.

H. M. Davenport, W. E. Powers, *"Affect of Low Cost Modifications on the Performance of an Undersized Electrostatic Precipitator,"* presented at 79th Air Pollution Control Association Conference, June 1986.

AWARDS

Engineer of the Year, 1991 – ENSR Consulting and Engineering, Camarillo
Engineer of the Year, 1986 – Naval Energy and Environmental Support Activity, Port Hueneme
Productivity Excellence Award, 1985 – U. S. Department of Defense

PATENTS

Sedimentation Chamber for Sizing Acid Mist, Navy Case Number 70094

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. 202-26-46
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	)))))	Order No. 202-26-47

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

Exhibit 5
Synapse Report

Memorandum

TO: EARTHJUSTICE, ENVIRONMENTAL LAW & POLICY CENTER, AND SIERRA CLUB

FROM: LUCY METZ AND DEVI GLICK

DATE: JANUARY 21, 2026

RE: COST OF CONTINUED OPERATION OF CULLEY UNIT 2 AND SCHAHFER UNITS 17–18 UNDER FEDERAL POWER ACT ORDERS

Executive Summary

Three coal units in Indiana—Culley 2, Schahfer 17, and Schahfer 18—were scheduled to retire at the end of 2025. However, the U.S. Department of Energy (DOE) issued two orders requiring the units to continue operating beyond their planned retirement dates.[1] This is concerning based on both cost and environmental impact.

We find that continued operation of the three units under economic commitment practices will result in net-costs[2] to the plant owners of $229,000 per day or $20.6 million over the initial 90-day order period. This includes $1.9 million for Culley 2, $9.8 million for Schahfer 17, and $8.9 million for Schahfer 18. If DOE additionally requires the three units to operate under a must-run commitment status (i.e., to remain online at a minimum dispatch level regardless of whether it is economic to do so), net losses would be even higher at $250,000 per day, or $22.5 million over the initial order period. Under either economic or must-run dispatch, costs will likely be passed on to ratepayers in the region—not taxpayers at large. We calculate these net losses based on the short-term gross costs associated with operating the coal units (fuel, variable operations and maintenance (VOM), and fixed operations and maintenance (FOM) costs) and the energy market revenues the units earn. These calculations assume that Schahfer 18 will be available over the 90-day period, although NIPSCO has stated Schahfer 18 will need repairs that will take longer than the initial 90-day period.

We assume that the units have no capacity value over the order period, based on the timing of MISO capacity auctions and the requirements of the DOE order, as we describe in more detail below.

The estimates above include short-term costs only. If DOE extends the order long-term, we estimate the coal units would require an additional $33.7 million per year in capital expenditures to replace

[1] U.S. Department of Energy. 2025. "2025 DOE 202(c) Orders." Available at: https://www.energy.gov/ceser/2025-doe-202c-orders.

[2] Net costs refer to gross costs net of MISO market energy revenues.

equipment as it wears out and install environmental controls to maintain compliance with environmental regulations.

Introduction

The Trump Administration's DOE has used authority under Section 202(c) of the Federal Power Act to issue several orders requiring power plants to remain online past their scheduled retirement dates. DOE first took this action with the J.H. Campbell Power Plant, a 1.5 GW coal plant in Michigan, on May 23, 2025. The initial order extended for 90 days. Since then, DOE has continued to issue orders extending the requirement for Campbell; the most recent order goes through mid-February 2026.[3] DOE issued similar orders for Eddystone Generating Station, an oil- and gas-fired power plant in Pennsylvania; Centralia Generating Station, a coal-fired plant in Washington; and Craig Station, a coal-fired plant in Colorado.[4]

Additionally, on December 23, 2025, DOE issued two Section 202(c) orders covering three coal units in Indiana scheduled to retire at the end of 2025: Culley 2, Schahfer 17, and Schahfer 18 (Table 1).[5] In this memo, we estimate the costs of a DOE order forcing Culley 2 and Schahfer 17–18 to remain online and generating electricity after December 31, 2025.

Table 1. Coal units scheduled for retirement

Unit	Location	Nameplate capacity (MW)	Online year	Scheduled retirement date	Owner
Culley 2	Warrick County, IN	103.7	1966	End of year 2025	CenterPoint
Schahfer 17	Jasper County, IN	423.5	1983	End of year 2025	NIPSCO
Schahfer 18	Jasper County, IN	423.5	1986	End of year 2025	NIPSCO

Source: U.S. Energy Information Administration (EIA) Form 860, 2024 release. NIPSCO is the Northern Indiana Public Service Company.

Methodology

We calculate the incremental cost of operating the units over the initial 90 days of the order (i.e., the net loss incurred by the unit owners relative to alternative resources), based on the coal units' short-term costs and energy revenues. Short-term costs include fuel, VOM, and FOM. We assume that in the short term, unit owners will not have time to make additional capital investments in the units. For any

[3] U.S. Department of Energy. 2025. "2025 DOE 202(c) Orders." Available at: https://www.energy.gov/ceser/2025-doe-202c-orders.
[4] Ibid.
[5] U.S. Department of Energy. 2025. "Federal Power Act Section 202(c): Culley Order No. 202-25-13." Available at: https://www.energy.gov/ceser/federal-power-act-section-202c-culley-order-no-202-25-13; U.S. Department of Energy. 2025. "Schahfer Order No. 202-25-12." Available at: https://www.energy.gov/ceser/federal-power-act-section-202c-schahfer-order-no-202-25-12.

units that were not operable as of the start date of the order, unit owners will likely not be able to complete the capital investments necessary to make the unit operable. However, for the sake of this analysis, we assume that each unit is operable for the 90-day period.

We also calculate the energy market revenue that the units generate over the order period. We assume that the units do not have any avoided capacity value, as explained below. We then calculate incremental costs by taking the difference between the gross short-term costs and the energy market revenue.

Finally, we calculate long-term costs if DOE orders the units to remain online for a year or more, including sustaining capital expenditures necessary to replace equipment at end-of-life and maintain environmental compliance.

Short-Term Gross Costs

To calculate short-term gross costs, we first estimate the capacity factors of the units using historical hourly generation data published by the U.S. Environmental Protection Agency.[6] We include two scenarios for capacity factors: one representing economic commitment (Table 3) and the other representing must-run commitment (Table 4 and Table 5):

- In the economic commitment scenario, we assume that the capacity factor of each unit during the term of the DOE order will be consistent with its average capacity factor over the past six years (2020–2025).
- In the must-run scenario, we re-calculate the capacity factor assuming that the units are committed in all hours. In hours when a unit was historically offline, we instead assume that generation never falls below the minimum dispatch level shown in Table 2, except for hours when the plant is in planned or unplanned outage.

We use outage rates, as shown in Table 2, from the North American Reliability Council's (NERC) Generating Availability Data System for coal units of a similar size to Culley 2 and Schahfer 17–18.[7] We then translate both sets of capacity factors into monthly quantities of coal consumption using heat rates from Horizon's National Database.[8] In Table 4, we apply outages evenly throughout the year for simplicity; in reality there would likely be several long planned maintenance outages in the spring and

[6] U.S. Environmental Protection Agency Clean Air Markets Program Data (CAMPD). 2025. Available at: https://campd.epa.gov/data/custom-data-download.

[7] North American Reliability Corporation (NERC). 2025. "Generating Unit Statistical Brochure 4 2020–2024 – All Units Reporting." Available at: https://www.nerc.com/programs/reliability-assessment--performance-analysis/generating-availability-data-system/gads-conventional/generating-unit-statistical-brochures.

[8] More information on Horizon Energy's National Database is available at https://www.horizons-energy.com/encompass/. Data in this dataset is from various sources, including: (1) the U.S. Energy Information Administration, (2) U.S. Environmental Protection Agency, (3) North American Electric Reliability Corporation, (4) Federal Energy Regulatory Commission (FERC), (5) ISO New England, and (6) various trade press announcements.

fall, and then shorter outages scattered randomly throughout the year. In Table 5, we do not apply any outages.

We project coal prices during the order period based on historical coal price data for each unit from the U.S. Energy Information Administration[9] and a year-on-year price trajectory for future years from Horizon's National Database. Because there is no consistent monthly pattern in the historical coal prices, we project fuel prices on an annual basis. We calculate total fuel costs by multiplying monthly coal consumption by fuel price. Finally, we estimate VOM and FOM using unit-specific values from the Horizons National Database.

Table 2. Coal unit parameters

Quantity	Culley 2	Schahfer 17	Schahfer 18
Minimum dispatch (MW)*	50	110	110
Heat rate (MMBtu/MWh)	12	11	11
Percent of hours in planned or unplanned outage	17%	18%	18%
Variable operations and maintenance (2025$/MWh)	$11	$8	$8
Fixed operations and maintenance (2025$/kW-year)	$66	$56	$56
Coal price in 2026 (2025$/MMBtu)	$2.95	$4.55	$4.55

Sources: Horizon's National Database; EIA Form 923, 2020–2024 releases and 2025 release through September 2025; and North American Reliability Corporation (NERC). 2025. "Generating Unit Statistical Brochure 4 2020–2024 – All Units Reporting." Available at: https://www.nerc.com/programs/reliability-assessment--performance-analysis/generating-availability-data-system/gads-conventional/generating-unit-statistical-brochures. To convert FOM costs from $/kW-year to $/MWh, multiply the value shown in the table by 1,000 kW/MW, divide by 8,760 hours/year, and then divide by the capacity factor.
**Note that the minimum dispatch level for Schahfer 17 and 18 differs based on source. We relied on EIA numbers, but looking at hourly CAMPD data, the minimum level looks closer to 160 MW.*

Energy Market Revenue

The coal units receive MISO energy market revenue during hours when they are online. We use market revenue to represent the avoided energy cost of the units—the costs that unit owners would have incurred to replace the energy from the units, if the units had been allowed to retire on schedule. To the extent that a utility would have otherwise relied on a resource that was less costly to operate than market energy, the reported savings would be even larger than what we estimate here. To estimate energy market revenue, we use around-the-clock energy market price projections from CenterPoint and

[9] EIA form 923, 2020–2024 releases and 2025 release through September 2025. Available at: https://www.eia.gov/electricity/data/eia923/.

NIPSCO's most recent integrated resource plans. The price is $43 per MWh (2025$) in 2026 for CenterPoint and $45 per MWh (2025$) for NIPSCO.[10,11]

We assume that the coal units do not have any capacity value, because the DOE orders require that the units "shall not be considered a capacity resource."[12] Additionally, the MISO capacity auction (Planning Resource Action or PRA) for the current planning year, which goes through May 31, 2026, occurred last spring.[13] The coal units were not bid in at this time because they were scheduled to retire. In general, resources that did not participate in the PRA can bid as replacement resources and receive zonal resource credits (ZRC) instead.[14] However, given that the DOE order says the coal units are not considered capacity resources, it seems unlikely they would have the opportunity to earn this revenue.

Short-Term Incremental Costs

We calculate the incremental cost of continued operation of the units by taking the difference between the short-term gross costs and the energy market revenues generated by each unit. The incremental cost represents the net loss that CenterPoint and NIPSCO will likely incur and pass on to their ratepayers because of the DOE order.

Long-Term Costs

In addition to any repairs needed in the near term to restore units to an operable condition, if DOE continues to order the units to operate long term, the units will require additional capital investments to replace equipment components that wear out and maintain compliance with environmental regulations. We estimate sustaining capital expenditures using a Sargent and Lundy survey of U.S. coal plant capital expenditures as a function of unit age.[15] There are no avoidable long-term costs associated with alternative resources.[16]

[10] CenterPoint Energy. 2025. *2025 Integrated Resource Plan.* Available at: https://www.centerpointenergy.com/en-us/business/services/integrated-resource-plan?sa=in.

[11] NIPSCO. 2024. *Integrated Resource Plan.* Available at: https://www.nipsco.com/docs/librariesprovider11/rates-and-tariffs/irp/nipsco_2024-irp.pdf.

[12] U.S. Department of Energy. 2025. "Federal Power Act Section 202(c): Culley Order No. 202-25-13." Available at: https://www.energy.gov/ceser/federal-power-act-section-202c-culley-order-no-202-25-13; U.S. Department of Energy. 2025. "Schahfer Order No. 202-25-12." Available at: https://www.energy.gov/ceser/federal-power-act-section-202c-schahfer-order-no-202-25-12.

[13] MISO Resource Adequacy Business Practices Manual, BPM-011-r32. Appendix K.

[14] MISO Resource Adequacy Business Practices Manual, BPM-011-r32. Section 6.4 Replacement Resources.

[15] Sargent & Lundy. 2018. *Generating Unit Annual Capital and Life Extension Costs Analysis: Final Report on Modeling Aging-Related Capital and O&M Costs.* Prepared for the U.S. Energy Information Administration. Available at: https://www.eia.gov/analysis/studies/powerplants/generationcost/pdf/full_report.pdf.

[16] There is no evidence that specific fixed or capital costs are being delayed or deferred at other resources as a result of the coal units being kept online.

Results

Short-Term Gross and Incremental Cost Results

The total gross cost to continue operating Culley 2 and Schahfer 17–18 for 90 days past December 23, 2025, is $512,000 per day, assuming economic commitment (Table 3). Over the 90-day initial order period, this adds up to a total gross cost of $46 million, including $4.2 million for Culley 2, $22.8 million for Schahfer 17, and $19.1 million for Schahfer 18. Table 3 shows the breakdown of these costs between fuel, VOM, and FOM.

Over the initial order period, the three units combined receive $25 million in energy market revenue, assuming economic commitment. Revenue is much lower than gross costs over this period, indicating that the unit owners incur net losses because of the DOE order. Continued operation of the plants causes a net loss of $229,000 per day, for a total of $20.6 million over the order period. This includes $1.9 million for Culley 2, $9.8 million for Schahfer 17, and $8.9 million for Schahfer 18.

Table 3. Cost to operate plants for the 90-day term of the December 2025 202(c) orders under economic commitment

Quantity	Culley 2	Schahfer 17	Schahfer 18	Total
Capacity Factor (%)	24%	33%	26%	—
Fuel costs (thousands 2025$)	$1,939	$14,586	$11,399	$27,924
VOM (thousands 2025$)	$581	$2,350	$1,837	$4,768
FOM (thousands 2025$)	$1,681	$5,841	$5,841	$13,363
Gross cost (thousands 2025$)	$4,200	$22,777	$19,077	$46,054
Energy market revenue (thousands 2025$)	($2,326)	($12,964)	($10,131)	($25,421)
Incremental (net) cost (thousands 2025$)	**$1,874**	**$9,814**	**$8,946**	**$20,633**
Gross cost per day (thousands 2025$/day)	**$47**	**$253**	**$212**	**$512**
Incremental (net) cost per day (thousands 2025$/day)	**$21**	**$109**	**$99**	**$229**

Notes: Gross costs are the sum of fuel costs, VOM, and FOM. Incremental costs are equal to gross costs minus energy market revenues.

If DOE additionally requires the three units to operate under a must-run commitment status, gross costs will be higher at $617,000 per day (Table 4). This results in a total gross cost of $56 million over the initial 90-day order period, including $6.6 million for Culley 2, $25.5 million for Schahfer 17, and $23.4 million for Schahfer 18. The higher costs are a result of the increased capacity factors in this scenario, which result in higher fuel and variable operations and maintenance costs. Net losses in this scenario are also higher at $250,000 per day, or $22.5 million over the entire study period. These results, shown in Table 4, assume average planned and unplanned maintenance outages. Table 5 shows must-run results assuming there are no planned or unplanned outages to book-end the results.

Table 4. Cost to operate plants for the 90-day term of the December 2025 202(c) orders under must-run commitment assuming maintenance and unplanned outages

Quantity	Culley 2	Schahfer 17	Schahfer 18	Total
Capacity Factor (%)	47%	38%	34%	–
Fuel costs (thousands 2025$)	$3,754	$16,960	$15,156	$35,869
VOM (thousands 2025$)	$1,124	$2,733	$2,442	$6,299
FOM (thousands 2025$)	$1,681	$5,841	$5,841	$13,363
Gross cost (thousands 2025$)	$6,558	$25,534	$23,440	$55,531
Energy market revenue (thousands 2025$)	($4,504)	($15,074)	($13,471)	($33,048)
Incremental (net) cost (thousands 2025$)	**$2,055**	**$10,460**	**$9,969**	**$22,484**
Gross cost per day (thousands 2025$/day)	**$73**	**$284**	**$260**	**$617**
Incremental (net) cost per day (thousands 2025$/day)	**$23**	**$116**	**$111**	**$250**

Table 5. Cost to operate plants for the 90-day term of the December 2025 202(c) orders under must-run commitment without maintenance and unplanned outages

Quantity	Culley 2	Schahfer 17	Schahfer 18	Total
Capacity Factor (%)	55%	43%	39%	–
Fuel costs (thousands 2025$)	$4,423	$19,089	$17,285	$40,797
VOM (thousands 2025$)	$1,324	$3,076	$2,785	$7,186
FOM (thousands 2025$)	$1,681	$5,841	$5,841	$13,363
Gross cost (thousands 2025$)	$7,428	$28,006	$25,912	$61,346
Energy market revenue (thousands 2025$)	($5,307)	($16,966)	($15,363)	($37,636)
Incremental (net) cost (thousands 2025$)	**$2,121**	**$11,040**	**$10,549**	**$23,710**
Gross cost per day (thousands 2025$/day)	**$83**	**$311**	**$288**	**$682**
Incremental (net) cost per day (thousands 2025$/day)	**$24**	**$123**	**$117**	**$263**

The Campbell coal plant, which has been operating under a Section 202(c) order since late May 2025, provides a point of comparison for these results. In a recent filing with the U.S. Securities and Exchange Commission, Consumers Energy, the owner of Campbell, reported incurring $164 million of gross costs to keep the plant online from late May through the end of September.[17] This is equivalent to $835 per

[17] Consumers Energy reported that it incurred a net loss of $53 million in the first order period, after applying $67 million in MISO revenues. For the portion of the second 202(c) order period through the end of September 2025, it incurred a net loss of $27 million after applying $17 million in revenue. This implies that total gross costs to operate the plant over both time periods was $164 million. See Consumers Energy Company Form 10-Q for the quarterly period ending September 30, 2025, filed with the U.S. Securities and Exchange Commission (SEC).

MW-day. Table 6 shows the gross cost results for Culley Unit 2 and Schahfer Units 17–18 converted to $/MW-day. Culley and Schahfer would have costs of $450–$598 per MW-day under economic commitment, which is 28–46 percent less than the cost at Campbell. Under must-run commitment (with outages), costs for Culley and Schahfer are in the range of $615–703 per MW-day, 16–26 percent less than the cost at Campbell. This suggests that the cost estimates presented here are conservative.

Table 6. Cost results for Culley and Schahfer converted to $/MW-day

Quantity	Culley 2	Schahfer 17	Schahfer 18
Gross costs under economic commitment (2025$/MW-day)	$450	$598	$501
Gross costs under must run commitment (with outages) (2025$/MW-day)	$703	$670	$615

There are several reasons that the cost to operate a unit beyond its planned retirement date may be higher than the historical cost to operate that unit. For example, plant owners may need to re-hire workers who have already found alternative employment, which can increase labor costs. Fuel costs may also be higher than historical values, especially if plant owners are not able to commit to long-term contracts for coal, given the uncertainty about how long the Section 202(c) order will extend. Additionally, a plant owner may have ramped down maintenance as the expected retirement of the asset approached. This means there may be a backlog of deferred maintenance required at the time the plant is re-started.

Long-Term Cost Results

In the long term, sustaining capital expenditures could add $33.7 million per year to the cost of operating the units, using generic assumptions for annual capital spending as a function of coal unit age (Table 7). If DOE orders the units to operate through 2030, the net present value of sustaining capital expenditures from 2026–2030 would be $156 million, including $18 million for Culley 2, $69 million for Schahfer 17, and $68 million for Schahfer 18. These totals include the annual investment value only and not the total associated revenue requirement (i.e., they do not include the cost of capital). They also do not include the cost of any near-term repairs necessary to make a unit operable. We understand from NIPSCO remarks at a recent Indiana Utility Regulatory Commission forum that Schahfer 18 requires repairs that could take over six months to make it operable again.[18]

Available at: https://d18rn0p25nwr6d.cloudfront.net/CIK-0000201533/676cb715-625b-4823-9435-1f928f1880bd.pdf.

[18] David Speakman. WFFT-TV. "Earthjustice warns NIPSO to not pass on coal plant reopening costs to customers." January 2, 2026. Available at: https://www.wfft.com/news/earthjustice-warns-nipsco-to-not-pass-on-coal-plant-reopening-costs-to-customers/article_5b0fdb80-4310-4328-83cf-5c7947ab6247.html.

Table 7. Estimate of sustaining capital expenditures if units remain online long-term

Quantity	Culley 2	Schahfer 17	Schahfer 18	Total
Cost in 2026 (thousands 2025$)	$3,957	$14,999	$14,793	$33,749
Net present value of costs 2026–2030 (thousands 2025$)	$18,235	$69,156	$68,218	$155,610

Source: Sargent & Lundy. 2018. Generating Unit Annual Capital and Life Extension Costs Analysis: Final Report on Modeling Aging-Related Capital and O&M Costs. Prepared for the U.S. Energy Information Administration. Available at: https://www.eia.gov/analysis/studies/powerplants/generationcost/pdf/full_report.pdf. Net present value calculation uses a discount rate of 7 percent, reflecting a typical nominal discount rate for a regulated utility.

As with the short-term costs, the estimates of sustaining capital expenditures presented here are conservative. Utilities tend to ramp down capital investment ahead of a unit's planned retirement. Utilities may also choose retirement when faced with high environmental compliance costs. This makes it more likely that units such as Culley and Schahfer operating beyond their planned retirement date will require substantial investments to replace aging equipment and ensure continued compliance with environmental regulations, beyond the investments necessary for units of similar age which had not planned to retire.

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. 202-26-46
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	)))))	Order No. 202-26-47

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

Exhibit 6
DOE Order No. 202-17-4
Summary of Findings

Summary of Findings
Department of Energy Order No. 202-17-4

September 14, 2017

Section 202(c) of the Federal Power Act (FPA) (codified at 16 U.S.C. § 824a(c)), through section 301(b) of the Department of Energy Organization Act (codified at 42 U.S.C. § 7151(b)), authorizes the Secretary of Energy, upon finding "that an emergency exists by reason of a sudden increase in the demand for electric energy, or a shortage of electric energy or of facilities for the generation or transmission of electric energy, or of fuel or water for generating facilities, or other causes," to issue an order "requir[ing] . . . such temporary connections of facilities and such generation, delivery, interchange, or transmission of electric energy as in [the Secretary's] judgment will best meet the emergency and serve the public interest." 16 U.S.C. § 824a(c)(1). If the order "may result in a conflict with [an] environmental law or regulation," then the Secretary must "ensure that such order requires generation, delivery, interchange, or transmission of electric energy only during hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable, is consistent with any applicable . . . environmental law or regulation and minimizes any adverse environmental impacts." *Id.* § 824a(c)(2). Orders issued under FPA section 202(c) "that may result in a conflict with [an] environmental law or regulation" expire 90 days after they are issued, but the Secretary "may renew or reissue such order[s] . . . for subsequent periods, not to exceed 90 days for each period, as [the Secretary] determines necessary to meet the emergency and serve the public interest." *Id.* § 824a(c)(4)(A).

The Department's regulations implementing FPA section 202(c) define the term "emergency" to mean, among other situations, "a specific inadequate power supply situation." 10 C.F.R. § 205.371. The regulations do not exhaustively list what qualifies as an emergency, but they note specifically that "[e]xtended periods of insufficient power supply as a result of inadequate planning or the failure to construct necessary facilities can result in an emergency as contemplated in these regulations." *Id.*

On June 13, 2017, PJM filed a *Request for Emergency Order Pursuant to Section 202(c) of the Federal Power Act* (Order Application) (included in the docket[1] of this Order) with the Department "to preserve the reliability of [the] bulk power transmission system in the North Hampton Roads area." Virginia Electric and Power Company[2] (Dominion), the electric utility serving the area, owns the coal-fired, power generating Units 1 and 2 at the Yorktown Power Station in Yorktown, Virginia. In November 2011 and October 2012, Dominion notified PJM of its plan to deactivate Units 1 and 2, respectively, effective December 31, 2014, because the units were not equipped to

[1] The docket of this Order is available at https://www.energy.gov/oe/downloads/federal-power-act-section-202c-dominion-energy-virginia-june-2017.
[2] *See* Dominion Energy, Inc., Form 10-Q filing, at 1 (Aug. 3, 2017), included in the docket of this Order.

comply with the Environmental Protection Agency's (EPA) Mercury and Air Toxics Standards (MATS), 40 C.F.R. part 63 subpart UUUUU. On June 24, 2014, pursuant to 40 C.F.R. § 63.6(i)(4)(i)(A), the Virginia Department of Environmental Quality granted Dominion a one-year MATS compliance extension for Yorktown Units 1 and 2.

On April 16, 2016, pursuant to section 113(a) of the Clean Air Act, 42 U.S.C. § 7413(a)(3) and (4), the EPA issued an Administrative Compliance Order (ACO) through April 15, 2017. The ACO implemented a 2011 MATS Enforcement Policy regarding issuance of section 113(a) administrative orders to sources that are unable to comply with the MATS but that may need to operate for up to a year to address a specific and documented reliability concern. The 2011 MATS Enforcement Policy was limited in application to units critical for reliability purposes. The EPA found that operation of Yorktown Units 1 and 2 met the policy criteria, as verified by the Federal Energy Regulatory Commission (FERC). Dominion has not achieved full compliance with the MATS for Yorktown Units 1 or 2 since the ACO expired, and section 113(a) of the Clean Air Act bars further compliance extensions.

Since Dominion's decision to retire the coal-fired Yorktown units, PJM has planned for their permanent deactivation by including required transmission upgrades in its own Regional Transmission Expansion Planning Process. PJM is subject to federal reliability standards enforced by the North American Electric Reliability Corporation (NERC), the Electric Reliability Organization designated by FERC. PJM holds the highest-level reliability responsibilities for the system it manages as a certified Reliability Coordinator, Balancing Authority, and Transmission Operator. PJM is also registered with NERC as a Planning Coordinator and Transmission Planner, among other functions. NERC Compliance Registry Active Entities List (updated Sept. 7, 2017), included in the docket of this Order. PJM applies reliability criteria to evaluate transmission system conditions and then develops the transmission solutions needed to ensure compliance with the reliability standards. The PJM Board of Managers approves those solutions in a Regional Transmission Expansion Plan (RTEP). Through its Transmission Expansion Advisory Committee (TEAC) and Sub-Regional RTEP Committees, PJM works with stakeholders throughout the RTEP's development. PJM Manual 14B, "Regional Planning Process," included in the docket of this Order. The PJM Board of Managers approved the transmission upgrades necessitated by the retirement of Yorktown Units 1 and 2 on May 17, 2012. TEAC Recommendations to the PJM Board (PJM Staff Whitepaper), May 2012, at 12, included in the docket of this Order.

PJM's approved solution was the Skiffes Creek Transmission Project, which consists of three components: a 500kV line, a 230kV line rebuild, and a new switching station. United States Army Corps of Engineers (Army Corps), Memorandum for the Record re: Department of the Army Environmental Assessment and Statement of Findings for the Above-Referenced Standard Individual Permit Application, CENAO-WR-RS (NAO-2012-00080 / 13-V0408), at 1, included in the docket of this Order. A

number of issues in the North Hampton Roads area, many of which are interrelated, needed to be addressed to avoid overloading transmission lines with too much power, as detailed in PJM's Deactivation Study. Yorktown Units 1 and 2 Generator Deactivation Notification: Deactivation Study Results – updated June 26, 2017 (PJM Deactivation Study), included in the docket of this Order. *See also Va. Elec. & Power Co.*, Commission Comments on Requests for EPA Administrative Orders, Docket No. AD16-11-000, 153 FERC ¶ 61,265 at PP 14-16 (2015).

PJM completed a series of analyses consistent with RTEP procedures, finding that only the Skiffes Creek Transmission Project—and none of the stakeholder-proposed alternatives—addressed the full range of potential reliability violations. Order Application, app. I, at 16. For example, reliance on operation of the oil-fired Yorktown Unit 3 generator would not address thermal overload and voltage violations on the 230kV and 115kV bulk electric system that PJM identified because of significant environmental operating restrictions and other plant operation constraints associated with that unit, including an 8 percent capacity factor limitation. *See id.*, app. II, at 18. As a result, PJM did not recommend reliance on Yorktown Unit 3 as a sustainable alternative solution to the identified reliability criteria violations. *Id.*

As part of PJM's analyses, Dominion transmission staff provided PJM with an analysis of system needs as well as potential solutions to the retirement of generating units at Yorktown and elsewhere. Dominion Update to Retirement Study Results (Mar. 10, 2012), included in the docket of this Order. Dominion's analysis, which was based on PJM's initial determination of reliability criteria violations that needed to be addressed, was independently validated by PJM and publicly vetted through the PJM stakeholder process before PJM staff recommended that the Board of Managers approve the Skiffes Creek Transmission Project. PJM Staff Whitepaper at 12, included in the docket of this Order.

PJM, as the Regional Transmission Organization (RTO) responsible for transmission system operation across multiple states, including Virginia, maintains its expert determination that the Skiffes Creek Transmission Project is the most effective and efficient solution to address the identified reliability criteria violations. Order Application, app. I, at 16. As recently as March 1, 2017, PJM provided the Army Corps with an analysis of proposed alternatives and found that none of them sufficiently resolved the identified violations. Letter to Col. Jason E. Kelly, U.S. Army Corps of Engineers (Mar. 1, 2017), included in the docket of this Order. PJM's subsequent RTEP materials reaffirm the need for the Skiffes Creek Transmission Project, even considering the updated, steadily rising load forecasts in the recently released 2017 PJM Load Forecast Report (included in the docket of this Order). *See* PJM Interconnection, L.L.C., 2017 RTEP Process Scope & Input Assumptions, rev. 1, at 25-27 (Aug. 3, 2017), included in the docket of this Order.

Construction of the Skiffes Creek Transmission Project began in July 2017 and is expected to take approximately 18-20 months. *Order No. 202-17-2 Renewal Application Filing* (Renewal Application) at 3. Until the Project is completed, a plan known as the North Hampton Remedial Action Scheme (RAS) remains in effect. According to NERC's Glossary of Terms, a RAS is "[a] scheme designed to detect predetermined System conditions and automatically take corrective actions that may include, but are not limited to, adjusting or tripping generation ([megawatts] and [megavolt amperes (reactive)]), tripping load, or reconfiguring a System(s)." Glossary of Terms Used in NERC Reliability Standards (updated Aug. 1, 2017), at 24, included in the docket of this Order.

To preserve the grid's reliability, the North Hampton RAS would allow PJM, the grid operator, to drop load—that is, shut off power to certain customers—to prevent voltage collapse. Dominion presented this RAS to PJM in January 2017, and the SERC Reliability Corporation, the NERC-delegated regional reliability enforcement entity, approved it that same month. *See* Dave Rees, *Dominion Virginia Power Sets Plan for Emergency Blackouts*, Daily Press, Jan. 13, 2017, included in the docket of this Order. If Yorktown Units 1 and 2 were unavailable, many N-1-1 contingencies could result in voltage collapse and thermal overloads. New Remedial Action Scheme, North Hampton RAS (Presentation to PJM), at 4, included in the docket of this Order; PJM Deactivation Study, included in the docket of this Order. According to FERC, "An N-1-1 contingency is a sequence of events consisting of an initial loss of a single generator or transmission element, followed by system adjustment, followed by another loss of a single generator or transmission element." *Price Formation in Energy and Ancillary Services Markets Operated by Regional Transmission Organizations and Independent System Operators*, Docket No. AD14-14-000, 153 FERC ¶ 61,221 at P 30 n.61 (2015).

The North Hampton RAS is on standby for use at PJM's discretion. If PJM detects the loss of certain facilities, it could trip the remaining feeds to the Yorktown area and drop service to approximately 150,000 customers, preventing voltage collapse. Rotating outages would follow until the system returns to normal operating parameters. New Remedial Action Scheme, North Hampton RAS (Presentation to PJM), at 6, included in the docket of this Order. According to U.S. Census estimates, the region PJM identifies as the North Hampton Roads load area in its Order Application had a population of more than 660,000 as of July 2016. At a minimum, rotating outages under the RAS would therefore impact, directly or indirectly, several hundred thousand people. United States Census Bureau, QuickFacts database, available at https://www.census.gov/quickfacts/fact/table/US/PST045216.

On July 3, 2017, the Army Corps issued a permit to Dominion for the Skiffes Creek Transmission Project pursuant to section 10 of the Rivers and Harbors Act of 1899 (33 U.S.C. § 403) and section 404 of the Clean Water Act (33 U.S.C. § 1344). On July

10, 2017, Dominion commenced construction of the Skiffes Creek Transmission Project. Renewal Application at 3.

On August 24, 2017, PJM filed its Renewal Application with DOE. The filing included all reports required by Order No. 202-17-2 (included in the docket of this Order). PJM said that construction of the Project was still expected to take 18-20 months, and that periodic transmission outages would be necessary to proceed apace with the Project. The same day, Dominion wrote to the Department that it "agrees with the Renewal Application and will operate in accordance with its provisions." Further, Dominion acknowledged that a 202(c) order "is not a long term solution to the reliability issues in the North Hampton Roads area on the Virginia Peninsula." The Skiffes Creek Transmission Project, underway as of July 2017, is the long-term solution.

On September 7, 2017, the Department received comments from Sierra Club opposing PJM's renewal request. On September 13, 2017, the Department received an answer to Sierra Club's comments from PJM. Both documents are included in the docket of this Order.

Discussion

Order No. 202-17-2 directs operation of Yorktown Units 1 and 2 as needed to address reliability issues, subject to a dispatch methodology submitted to the Department for review. The reliability issues noted in Order No. 202-17-2 were described as Scenario One, increased load due to weather-related temperature extremes, and Scenario Two, decreased transmission capacity required by the RTEP upgrade. Scenario Two was contemplated but not yet applicable when Order No. 202-17-2 was issued because the Army Corps permit application for the Skiffes Creek Transmission Project was still pending. On July 3, the Army Corps issued Permit No. NAO-2012-00080, resulting in the potential need to operate Yorktown Units 1 and 2 to address both Scenario One and Two reliability issues. To date, in accordance with Order No. 202-17-2, PJM has directed operation of Yorktown Units 1 and/or 2 for all or part of 13 days. PJM Interconnection, L.L.C., Report on Yorktown Units 1 and 2 Operations Pursuant to Order No. 202-17-2, Attachment 1, included in the docket of this Order; Telephone call to Steven Pincus, Associate General Counsel, PJM, Sept. 11, 2017.

Scenario One applies when load conditions exceed a certain threshold due to local transmission issues that would cause PJM to operate the system outside its normal operating parameters.[3] Weather-related temperature extremes are one example of such a local transmission issue. Scenario Two is also triggered when load conditions exceed a certain threshold, but the threshold is lowered depending on the particular construction-related transmission outages in effect as the Skiffes Creek Transmission Project is built.

[3] Exact load thresholds were submitted as critical electric infrastructure information and are thus not described here so as not to provide vulnerability information on critical infrastructure.

Because the Project minimizes environmental impacts by utilizing existing transmission line rights-of-way to the extent possible, portions of existing transmission lines must be taken offline for upgrades. Under either scenario, when the relevant thresholds are exceeded, to prevent system overload and uncontrolled power disruptions, PJM must implement the North Hampton RAS. The only sufficient alternative to the RAS and its resulting outages for up to approximately 150,000 customers is the emergency operation of Yorktown Units 1 and 2. The demand response available to PJM is a small fraction of the load threshold and is "not sufficient to ensure reliable service." Order Application, app. II, at 18. Likewise, Dominion has limited demand-side management and curtailment capabilities, insufficient for reliability purposes even when fully deployed. *See id.*, app. III, at 21.

Activating the RAS would immediately interrupt service to load in the North Hampton Roads area. PJM asserts that, according to the RAS, during certain high load conditions, this "load shedding" could result in the loss of roughly 950 MW of electric power—that is, the loss of service to over 150,000 North Hampton Roads area customers. Order Application at 9. This service interruption could last hours or even days. *See* North Hampton RAS Presentation to PJM, at 8, included in the docket of this Order. Activating the RAS is not a gradual approach that presents a wide range of likely impacts; it is an extreme measure with immediate consequences to 150,000 customers. While the RAS is designed to prevent more catastrophic, uncontrolled grid impacts from occurring, load shedding of this magnitude is significant, and would trigger mandatory reporting both to DOE and FERC. DOE Form OE-417 requires reporting within one hour for "[l]oad shedding of 100 Megawatts or more implemented under emergency operational policy," and within six hours for "[l]oss of electric service to more than 50,000 customers for 1 hour or more." This is the same level of reporting triggered by a cyber or other hostile attack on grid resources. Form OE-417, Electric Emergency Incident and Disturbance Report, https://www.oe.netl.doe.gov/docs/OE417_Form_03312018.pdf. Similarly, FERC and NERC mandate notification for a variety of serious events including when a bulk electric system emergency triggers automatic load shedding of 100 MW or more, as in the RAS. *See* North American Electric Reliability Corporation, Reliability Standard EOP-004-3 (Event Reporting), http://www.nerc.com/_layouts/PrintStandard.aspx?standardnumber=EOP-004-3&title=Event%20Reporting.

To underscore the potential impact of RAS activation, the estimated 150,000 impacted customers are counted by meter, not individual. One or more meters could translate to large household or commercial or industrial facilities, including those critical to health and safety systems. Whether counted as 150,000 or that amount multiplied several times over, the anticipated impact of this emergency situation is on par with or exceeds the impacts described in prior 202(c) orders. *Crisp Cnty. Power Comm'n v. Ga. Power Co.*, 35 FPC 629, 630-31 (1966) (ordering interconnection to prevent, in part,

outages lasting more than an hour and affecting 500 to 2,000 customers on Crisp County, Georgia's system). *City of Cleveland, Ohio v. Cleveland Elec. Illuminating Co.*, 47 FPC 747, 749 (1972) (ensuring reliable service was provided to the approximately 20% of the city's consumers). Cleveland's 1970 Census-reported population was 750,903, suggesting that just over 150,000 individuals were affected by the 1972 202(c) order. *See* https://www.census.gov/population/www/documentation/twps0027/tab20.txt. As described earlier, the U.S. Census estimated the population of the North Hampton Roads load area at nearly 661,000 people just over a year ago.

A benefit of the planning efforts mandated by federal reliability standards is that entities such as PJM can accurately forecast the impacts to the bulk power system in steady-state and various contingency event situations. Thus, as reliability planning continues to mature, there should be fewer electric energy shortages that take bulk power system owners, operators, and regulators by surprise. That planners can identify conditions under which shortages may occur, however, does not rule out electric energy shortages constituting emergencies under FPA section 202(c) and the Department's implementing regulations. It is impossible to plan for every contingency, and challenges may arise even when implementing the most prudent plans. FPA section 202(c) affords the Secretary of Energy discretion in finding when an emergency exists and how best to meet the emergency and serve the public interest.

Here, an emergency exists due to the imminent possibility of implementing the North Hampton RAS under a range of both steady-state and contingency events, including potential transmission congestion preventing the delivery of available generation to the North Hampton Roads area. PJM Deactivation Study at 1-2, included in the docket of this Order. The RAS would leave approximately 150,000 customers without power, including residential, industrial, commercial, health and safety facilities, major national defense, and educational institutions. *See* Order Application, app. IV, at 30-31. That creates serious health and safety issues. Issuance of today's Order meets the emergency and serves the public interest.

In these circumstances, transmission outages, like those contemplated for or otherwise in connection with the construction of the Skiffes Creek Transmission Project, constitute an emergency for purposes of a section 202(c) order. As stated earlier, the Department's implementing regulations, in their current form since 1981, contemplate that "[e]xtended periods of insufficient power supply as a result of inadequate planning or the failure to construct necessary facilities [may create] an emergency." 10 C.F.R. § 205.371. The regulations add that "[i]n such cases, the impacted 'entity' will be expected to make firm arrangements to resolve the problem until new facilities become available, so that a continuing emergency order is not needed." *Id.* PJM, the impacted entity in this case, requested today's Order. Through the RTEP, PJM made firm arrangements to resolve the problem through the Skiffes Creek Transmission Project, which is now permitted and under construction. That construction was delayed due to events beyond

PJM's control has no bearing on the likelihood of power outages for 150,000 customers. Such a power loss event would also constitute an emergency as contemplated by FERC in its Public Utility Regulatory Policies Act of 1978 regulations, which define "system emergency" as "a condition on a utility's system which is likely to result in imminent significant disruption of service to customers or is imminently likely to endanger life or property." 18 C.F.R. § 292.101(b)(4). The risk faced by 150,000 customers will continue, assuming the Skiffes Creek Transmission Project construction schedule is met, for approximately another 18 months. Today's Order is limited in time and specifically tailored to address an emergency contemplated both in the authorizing statute and the Department's implementing regulations.

Between 2005 and 2007, DOE issued orders under similar circumstances, directing the Mirant Potomac River Generation Station to operate until two new 230kV transmission lines could be built to ensure reliability to a portion of the District of Columbia. *See* Order No. 202-5-3 (relying on DOE regulatory definition of emergency as including extended periods of insufficient power supply as a result of inadequate planning or the failure to construct necessary facilities). In a series of orders under FPA section 202(c), the Secretary ordered operation of the generation units while the two existing 230kV lines that supplied the central District of Columbia area were temporarily and sequentially removed from service to connect the new lines. Neither the problems leading up to the closure of the generating units nor the need for a particular transmission solution were unexpected. Nevertheless, the Department found that imminent power shortages, faced if contingency events occurred, constituted an emergency under the Federal Power Act. Order Nos. 202-5-3, 202-6-1, 202-6-2, 202-7-1, and 202-7-2.

In this matter, the likelihood of RAS activation is not theoretical. While Order No. 202-17-2 was in effect, PJM had to call upon Yorktown Units 1 and/or 2 on 13 days over three months. Absent Order No. 202-17-2, the RAS would have been activated instead. The alternatives available to PJM and Dominion are not sufficient to ensure reliability without available capacity from Yorktown Units 1 and 2. As described, PJM and Dominion cannot mobilize adequate alternatives to counter the loss of transmission during construction of the Skiffes Creek Transmission Project. For example, demand response resources, while potentially helpful at the margin, are insufficient to address either Scenario One or Scenario Two. *See* Order Application, app. II, at 18. Further, PJM's recent RTEP Input Assumptions and Scope Whitepaper indicates that Dominion theoretically has up to 130 MW of distributed solar generation available during the summer. 2017 RTEP Process Scope and Input Assumptions, rev. 1, tbl.3.2, at 18 (Aug. 3, 2017), included in the docket of this Order. Outside of ramp-up and ramp-down times, each Yorktown Unit typically ran at 100 MW output or higher, day or night, when operational while Order No. 202-17-2 was in effect. PJM Interconnection, L.L.C., Report on Yorktown Units 1 and 2 Operations Pursuant to Order No. 202-17-2, Attachment 1. Distributed generation is an intermittent resource; even under ideal conditions, with full-capacity, daytime generation and load reduction at the height of the

summer, distributed generation generally would still not have offset the baseload generating capacity needed to ensure reliability on the North Hampton Roads area grid. And any flexibility for scheduling the Skiffes Creek Transmission Project's construction during historically low-load periods ended when the EPA ACO expired, as expeditious completion of the Project is now the priority. Therefore, even if PJM and Dominion made full use of available alternatives, capacity from Yorktown Unit 1, 2, or both would still be necessary to meet the emergency and serve the public interest.

FPA section 202(c)(2) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law or regulation be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable, [be] consistent with any applicable . . . environmental law or regulation and minimize[] any adverse environmental impacts." Certain load conditions may necessitate operation of Yorktown Units 1 and 2.

To minimize the hours of operation and adverse environmental impacts, the Order contains certain limitations. First, DOE maintains consistency with EPA's approach in the 2016 ACO by authorizing operation of Yorktown Units 1 and 2 only when called upon by PJM for reliability purposes. The Department consulted with EPA and has reviewed data provided by PJM and Dominion on operations, air emissions, and water usage. This Order will continue the operational limitations described in EPA's above-referenced ACO, AED-CAA-113(a)-2016-0005. Second, DOE requires that PJM and Dominion, consistent with good utility practice, first exhaust all reasonably and practically available resources, including demand response and behind-the-meter generation resources, before operating Yorktown Units 1 and 2. Third, DOE requires continued compliance with the June 27 dispatch methodology, which was reviewed by the Department, and which remains subject to continuing oversight by the Department. In particular, the dispatch methodology establishes Yorktown Units 1 and 2 commitment procedures, describes the utilization and trip conditions of the North Hampton RAS for mitigating congestion on the Virginia Peninsula or North Hampton Roads area, and describes Dominion's mitigation options for the existing James River tower contingency. The dispatch methodology is an operating protocol that limits the ability of PJM to dispatch Yorktown Units 1 and 2 only when needed to mitigate reliability issues associated with scheduled and emergency transmission outages directly related to the Skiffes Creek Transmission Project and other local transmission issues. The EPA ACO recognized that such a dispatch methodology, under which PJM determines when the Yorktown units are needed for reliability issues, serves the objective of minimizing emissions. ACO at 8-9, included in the docket of this Order. Fourth, to track when Yorktown Units 1 and 2 are operated to maintain grid reliability and to monitor associated air emissions and water usage, reports will be required every two weeks going forward. If the Department becomes concerned with PJM or Dominion's compliance with this Order, enforcement actions are available, up to and including termination of the underlying order.

While DOE has constrained PJM's operations with regard to Yorktown Units 1 and 2, it is necessary to preserve reasonable discretion for PJM, as a Transmission Operator, to address the second-to-second operational challenges of grid management. This follows DOE's practice in earlier orders issued under FPA section 202(c), which prioritized reliability concerns as identified and assessed by the operator. For example, Order No. 202-02-1 (Aug. 16, 2002) ordered Cross-Sound Cable Company, LLC to operate a cable across Long Island Sound, limiting "transmission and delivery of . . . electric capacity and/or energy [to that] necessary in the judgment of the New York Independent System Operator [ISO] to meet the supply and essential reserve margin needs of the Long Island Power Authority [LIPA]," but only "in order for LIPA to serve its firm retail customers after it has implemented all available load reduction measures consistent with good utility practice." Order No. 202-03-1 (Aug. 14, 2003) directed operation of the same cable, but specifically ordered the New York ISO and ISO New England to require Cross-Sound Cable Company to operate the cable. That order also required both RTOs to "consult with each other and with appropriate reliability organizations." Today's Order similarly requires PJM to identify and mitigate reliability issues in accordance with DOE's specified operational limitations.

In considering renewal or reissuance of an order under FPA section 202(c) that may conflict with an environmental law or regulation, DOE is required to "consult with the primary Federal agency with expertise in the environmental interest protected by such law or regulation" and to include "conditions as such Federal agency determines necessary . . . to the extent practicable." 16 U.S.C. § 824a(c)(4). The EPA is the primary federal agency in this case with expertise in the protected environmental interest, specifically MATS and section 316(b) of the Clean Water Act, and the Department consulted with EPA after receiving the Renewal Application. Email from Acting Assistant Administrator Starfield, Office of Enforcement and Compliance Assurance, to Acting Under Secretary for Science and Energy Hoffman (Sept. 11, 2017), included in the docket of this Order. After consulting with EPA, and consistent with that consultation, the Department found that the only appropriate short-term emissions limitation on Yorktown Units 1 and 2 would be to curtail operating hours to the maximum extent practical for reliability purposes.

Pursuant to the National Environmental Policy Act of 1969, the Department has determined that issuance of this Order fits within the category of actions included in Categorical Exclusion (CX) B4.4 and otherwise meets the requirements for application of a CX. The Order fits within the category of actions because it authorizes "[p]ower marketing services and power management activities (including, but not limited to, storage, load shaping and balancing, seasonal exchanges, and other similar activities), provided that the operations of generating projects would remain within normal operating limits." Records of Categorical Exclusion Determination, Order No. 202-17-4, Sept. 11, 2017, included in the docket of this Order.

For the reasons stated above, the Secretary of Energy finds that an emergency exists threatening imminent electric energy shortages, and that this Order is necessary to address the emergency and serve the public interest in the North Hampton Roads area. The limitations on operation set forth in Order No. 202-17-4 and outlined above are, to the maximum extent practicable, consistent with applicable environmental laws or regulation and minimize any adverse environmental impacts, and the reporting requirements for operations and estimated emissions ensure transparency of implementation.

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. 202-26-46
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	)))))	Order No. 202-26-47

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

Exhibit 7
DOE Order No. 202-02-1

Department of Energy
Washington, DC 20585

Order No. 202-02-1

Pursuant to the authority vested in me by section 202(c) of the Federal Power Act, 16 U.S.C. 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. 7151(b), I hereby determine that an emergency exists on Long Island in the State of New York due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, a shortage of facilities for the transmission of electric energy and other causes, and that issuance of this order will alleviate the emergency and serve the public interest. Based on this determination, I hereby order:

From the effective date and time of this order until 12:01 a.m. Eastern Daylight Time, October 1, 2002, Cross-Sound Cable Company, LLC is directed to operate the Cross-Sound Cable and related facilities connecting substations in New Haven, Connecticut and Shoreham, Long Island, New York, to transmit and deliver electric capacity and/or energy when, as and in such amounts as may be scheduled and purchased by the Long Island Power Authority (LIPA), and to take such actions as are necessary in order to enable it to do so, including but not limited to energizing and continuing to energize the facilities of Cross-Sound Cable Company, LLC; *provided*, that this order otherwise shall be limited to requiring the transmission and delivery of such electric capacity and/or energy as is necessary in the judgment of the New York Independent System Operator to meet the supply and essential reserve margin needs of LIPA, in order for LIPA to serve its firm retail customers after it has implemented all available load reduction measures consistent with good utility practice, including curtailing and/or terminating service to interruptible customers, public appeals for conservation, reducing 30 minute reserves to zero, and implementing voltage reductions; *and provided further*, that prior to exercising its judgment as required by this order, the New York Independent System Operator must consult with ISO New England, Inc. to ensure that the scheduling of such electric capacity and/or energy will not violate system operating criteria, and the New York Independent System Operator should, as practicable, consult with appropriate reliability organizations. If necessary, just and reasonable terms for the transmission and delivery of electric capacity and/or energy pursuant to this order, including the compensation therefor, shall be established by a supplemental order issued pursuant to Federal Power Act section 202(c).

Nothing in this order shall preclude use of the energized Cross-Sound Cable and its related facilities connecting substations in New Haven, Connecticut and Shoreham, Long Island, New York, to transmit and deliver electric capacity and/or energy from Long Island to Connecticut or from Connecticut to Long Island in accordance with the operating and scheduling protocols and decisions of the New York Independent System Operator and ISO New England, Inc.

This order shall be effective upon its issuance.

Issued in Washington, D.C. at 2:38PM this 16th day of August, 2002.

Spencer Abraham
Secretary of Energy

Printed with soy ink on recycled paper

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. 202-26-46
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	)))))	Order No. 202-26-47

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

Exhibit 8
Cooke Email to Alle-Murphy

-----Original Message-----
From: Alle-Murphy, Linda
Sent: Wednesday, December 28, 2005 9:05 AM
To: Mansueti, Lawrence
Subject: Re: Order No. 202-05-3

Dear Mr. Mansueti,

I am an associate at Schnader Harrison Segal and Lewis, working together with John Britton, who represents the City of Alexandria in the Mirant Power Plant matter. I have a few procedural questions regarding the application for rehearing.

According to Section VI.H. of Order No. 202-05-3, applications for rehearing in this matter should be addressed to you. Section VI.H. cites to 16 U.S.C. Section 825(l), which refers to the "Commission" (FERC). I am just seeking to confirm that Section 825(l) also applies to this DOE proceeding.

Also, are 10 CFR Section 1003.1 et seq., Office of Hearings and Appeals Procedural Regulations applicable to this proceeding (e.g. re service requirements, etc.) If not, are there other procedural rules that apply to this proceeding?

Thank you very much for your assistance! You may respond by return e-mail or, if that is not convenient for you, by telephone or fax.

Linda Alle-Murphy
Linda B. Alle-Murphy
Schnader Harrison Segal & Lewis LLP
1600 Market Street, Suite 3600
Philadelphia, PA 19103-7286

From: Cooke, Lot
Sent: Friday, December 30, 2005 8:51 AM
To: 'LAlle-Murphy@Schnader.com'
Subject: Rehearing procedures for DOE Order No. 202-05-3

Dear Ms. Alle-Murphy:

In response to your emailed question to Mr. Mansueti--

The DOE Organization Act transferred the authority of the Federal Power Commission to the Secretary, except for authority over rates and charges for the transmission and sale of electric energy, which was transferred to FERC. Federal Power Act (FPA) Section 202(c) emergency authority was generally and specifically given to the Secretary.

An order issued under the FPA is only reviewable pursuant to the rehearing provisions contained in section 313 of the FPA, so that is the applicable provision under which to seek rehearing of the December 20,
2005 order.

The DOE regulations on emergency orders, 10 CFR section 205.370, et seq., do not a have specific rehearing section, but a party seeking rehearing can look for procedural guidance to FERC's Rules of Practice and Procedure, 18 CFR Part 385. In particular the rehearing regulations contained at 18 CFR section 385.713 and the service requirement contained at 18 CFR section 385.2010. The Office of Hearings and Appeals procedures are not applicable as the Secretary will make the rehearing decision pursuant to FPA section 313.

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. 202-26-46
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	)))))	Order No. 202-26-47

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

Exhibit 9
DOE Order No. 202-22-4

Department of Energy
Washington, DC 20585

Order No. 202-22-4

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and delegated by email correspondence (Dec. 23, 2022), and for the reasons set forth below, I hereby determine that an emergency exists in the electricity grid operated by PJM Interconnection, LLC (PJM) due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

Emergency Situation

On December 24, 2022, PJM, the Regional Transmission Operator (RTO) for 65 million people in thirteen states and the District of Columbia (the PJM Region), filed a *Request for Emergency Order Under Section 202(c) of the Federal Power Act* (Application) with the United States Department of Energy (Department) "to preserve the reliability of the bulk electric power system."

The PJM Region, like many regions across the country, is currently being affected by a severe winter weather system. PJM states that this weather system caused a significant drop in temperatures across the PJM Region on December 23, 2022, accompanied by high winds in excess of 40 mph. As a consequence of the impact of wind and decreasing temperatures, the demand for electricity in the PJM Region rose to an unusually high peak load on the evening of December 23, 2022, in excess of 135,000 MW. This severely cold weather is expected to last through Sunday morning.

While the vast majority of generating units in the PJM Region continue to function adequately under these stressed conditions, some units have experienced operating difficulties due to cold weather or fuel limitations, primarily gas. Specifically, approximately 45,000 MW of generating units (the majority of which are thermal) are currently outaged or derated. PJM has expressed its concern that these units will be unable to return to service over at least the next 48 hours, which coincides with the time period for which PJM is requesting this Order. Since these units may not promptly return to service, and in the event PJM experiences additional generating unit outages, PJM states that it may need to curtail some amount of firm load on December 24, December 25, or December 26, 2022 in order to maintain the security and reliability of the PJM system.

Description of Mitigation Measures

In its Application, PJM identifies the measures it is taking to ensure the supply of generation will continue to be sufficient to meet system demand and reserve requirements. On December 20, 2022, PJM issued a cold weather advisory in the PJM Region in anticipation of the forecasted weather conditions. Then on December 23, 2022, PJM issued

a PJM Region-wide cold weather alert which further highlighted PJM's expected need to call higher-than-normal generation resources in light of the anticipated weather.

On December 23, 2022, generating reserves diminished to a level that required PJM to declare an Energy Emergency Alert (EEA) Level 2 and take other emergency actions. PJM states that after having exhausted economic operation, PJM triggered a Maximum Generation Emergency Action to increase the PJM Region generation above the maximum economic level. Further, PJM triggered its load management reduction actions to provide additional load relief by using PJM-controllable load management programs. PJM called on demand response providers and curtailment service providers to reduce load. PJM also issued public appeals for consumers to reduce usage. PJM has continued to employ these emergency actions through December 24, 2022, and anticipates needing to continue them through the order end date that it has requested.

Since December 23, 2022, PJM has also taken additional measures to provide additional reserves, including:

- Reducing exports to neighboring regions and requested shared reserves for neighboring regions; consistent with joint operating agreements and other regulatory requirements, PJM has continued to communicate and collaborate with its interconnected neighboring systems when the demand on the PJM system has exceeded expected energy and reserve requirements and when emergency transfers were required to support PJM's interconnected neighboring systems;
- Issuing additional public conservation appeals;
- Running uneconomic generation during lower load periods to ensure their availability during peak conditions;
- Utilizing its Emergency Procedures to assist in maximizing the pumped storage hydro generation levels;
- Communicating and preparing transmission and distribution service providers to implement distribution voltage reduction measures; and
- Communicating and preparing transmission and distribution service providers to implement firm load shed.

In its Application, PJM committed to continue to take such actions, including utilizing other supply resources before calling upon any generators to operate in excess of permitting levels. According to PJM, it is nevertheless possible that the measures it has and will take may not be sufficient to avoid the need to curtail firm load in order to ensure system reliability.

Request for Order

PJM requests that the Secretary issue an order immediately, effective today, December 24, 2022, through 12:00 p.m. Eastern Time on Monday, December 26, 2022, authorizing the electric generating units identified in Exhibit A, as well as any other

generating units subject to emissions or other permit limitations in the PJM Region to operate up to their maximum generation output levels under the limited circumstances described in this Order, notwithstanding air quality or other permit limitations. The generating units (Specified Resources) that this Order pertains to are listed on the Order 202-22-4 Resources List, as described below.

ORDER

Given the emergency nature of the expected load stress, the responsibility of PJM to ensure maximum reliability on its system, and the ability of PJM to identify and dispatch generation necessary to meet the additional load, I have determined that, under the conditions specified below, additional dispatch of the Specified Resources is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). This determination is based on, among other things:

- The emergency nature of the expected load stress caused by the current cold weather event threatens to cause loss of power to homes and local businesses in the areas that may be affected by curtailments, presenting a risk to public health and safety.
- The expected shortage of electric energy, shortage of facilities for the generation of electric energy, and other causes in the PJM Region demonstrate the need for the Specified Resources to contribute to the reliability of the PJM Region.
- PJM is responsible to ensure maximum reliability on its system, and, with the authority granted in this Order, its ability to identify and dispatch generation, including the Specified Resources, necessary to meet the additional load resulting from the cold weather event is enhanced.

In line with the anticipated circumstances precipitated by the cold weather event, this Order is limited to the period beginning with the issuance of this Order on December 24, 2022 through 12:00 pm Eastern Time on December 26, 2022. Because the additional generation may result in a conflict with environmental standards and requirements, I am authorizing only the necessary additional generation on the conditions contained in this Order, with reporting requirements as described below.

FPA section 202(c)(2) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law and minimize any adverse environmental impacts. PJM anticipates that this Order may result in exceedance of emissions of sulfur dioxide, nitrogen oxide, mercury, and carbon monoxide emissions, as well as wastewater release limits. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by PJM for reliability purposes.

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

A. From the time this Order is issued on December 24, 2022, to 12:00 pm Eastern Time on December 26, 2022, in the event that PJM determines that generation from the Specified Resources is necessary to meet the electricity demand that PJM anticipates in the PJM Region during this event, I direct PJM to dispatch such unit or units and to order their operation only as needed to maintain the reliability of the power grid in the PJM Region when the demand on the PJM system exceeds expected energy and reserve requirements. Specified Resources are those generating units set forth on the Order 202-22-4 Resource List, subject to updates directed here and as described in paragraph D, which the Department shall post on www.energy.gov.

B. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by PJM for reliability purposes. Consistent with good utility practice, PJM shall exhaust all reasonably and practically available resources, including available imports, demand response, and identified behind-the-meter generation resources selected to minimize an increase in emissions, to the extent that such resources provide support to maintain grid reliability, prior to dispatching the Specified Resources. PJM shall provide a daily notification to the Department reporting each generating unit that has been designated to use the allowance and operated in reliance on the allowances contained in this Order.

In furtherance of the foregoing and, in each case, subject to the exhaustion of all available imports, demand response, and identified behind-the-meter generation resources selected to minimize an increase in emissions available to support grid reliability:

(i) For any generation resource whose operator notifies PJM that the unit is unable, or expected to be unable, to produce at its maximum output due to an emissions or other limit in any federal environmental permit, and during the pendency of a PJM-triggered Maximum Generation Emergency Action, at any point before 12:00 Eastern Time on Monday, December 26, 2022, the unit will be allowed to exceed any such limit only during any period for which PJM has declared an Energy Emergency Alert (EEA) Level 2 or Level 3 (during which time PJM will have triggered a Maximum Generation Emergency Action), except as described in item (iii) below in certain limited circumstances in anticipation of an EEA Level 2. Once PJM declares that the EEA Level 2 event has ended, the unit would be required to immediately return to operation within its permitted limits. And at all other times, the unit would be required to operate within its permitted limits, except for the limited exceptions provided herein for operations in anticipation of an EEA Level 2 to prevent the cycling of units or facilitate the charging or pumping of other resources necessary for the EEA Level 2.

(ii) For any generation resource whose operator notifies PJM that the unit is offline or would need to go offline at any point before 12:00 Eastern Time on Monday, December 26, 2022, due to an emissions or other limit in any

federal environmental permit, PJM may direct the unit operator to bring the unit online, or to keep the unit online, and to operate at the level consistent with its permits but subject to the exceptions set forth in this Order. In this circumstance, the operator is allowed to make all of the unit's capacity available to PJM for dispatch during any period for which PJM has declared an EEA Level 2 or 3 (during which time PJM has triggered a Maximum Generation Emergency Action), except as described in item (iii) below in certain limited circumstances in anticipation of an EEA Level 2. Once PJM declares that such an EEA Level 2 event has ended and the Maximum Generation Emergency Action is discontinued, the unit would be required to immediately return to operating at a level below the higher of its minimum operating level or the maximum output allowable under the permitted limit.

(iii) PJM is hereby granted authority to operate the Specified Units that are combined cycle generating units in certain limited circumstances in advance of declaring an EEA Level 2, Maximum Generation Emergency, or in between such events, where such operation or continued operation of the Specified Resource is reasonably necessary to avoid shutting down and restarting the Specified Unit. PJM has represented that such cycling of units can cause reliability issues regarding restarting, delays, and increased emissions during start up. PJM is further authorized to operate the Specified Units in certain limited circumstances in advance of the declaring an EEA Level 2, Maximum Generation Emergency where such operation or continued operation of the Specified Resource is reasonably necessary to facilitate charging storage resources or pumping for pumped storage facilities that will needed during an anticipated EEA Level 2. PJM is required to take measures to dispatch units for which cycling would otherwise be required in a manner reasonably intended to limit the duration and operating level of those units in such a way as to minimize exceedance of permit limitations consistent with the security and reliability of the PJM Region.

(iv) To minimize adverse environmental impacts as set forth herein, this Order limits operation of dispatched units to the times and within the parameters determined by PJM for reliability purposes. Consistent with good utility practice, and notwithstanding standard merit order dispatch, PJM shall exhaust all reasonably and practically available resources, including available imports, demand response and identified behind-the-meter generation resources selected to minimize an increase in emissions to the extent that such resources provide support to maintain grid reliability prior to dispatching the Specified Resources at levels above their permitted emissions levels. PJM shall provide a daily notification to the Department reporting each generating unit that has been designated to use the allowance and operated in reliance on the allowances contained in this Order.

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

D. In the event that PJM identifies additional generation units that it deems necessary to operate in excess of federal environmental permitting limits in order to maintain the reliability of the power grid in the PJM Region when the demand on the PJM system exceeds expected energy and reserve requirements, PJM shall provide prompt written notice to the Department of Energy at AskCR@hq.doe.gov with the name and location of those units that PJM has identified, as well as additional notice by the same means through updating Exhibit A to its Application with such additional generation units, the fuel type of such unit, and the anticipated category of environmental impact, at 09:00 Eastern Time or 21:00 Eastern Time, whichever follows closest in time to the unit identification by PJM to the greatest extent feasible. Such additional generation unit shall be deemed a Specified Resource for the purpose of this Order for the hours prior to the required written notice to the Department updating Exhibit A, and PJM may dispatch such additional generation units, provided that if the Department of Energy notifies PJM that it does not approve of such generation unit being designated as a Specified Resource, such generation unit shall not constitute a Specified Resource upon notification from the Department. The Department shall post an updated Order 202-22-4 Resource List as soon as practicable following notification from PJM under this paragraph.

E. PJM shall provide such additional information regarding the environmental impacts of this Order and its compliance with the conditions of this Order, in each case as requested by the Department of Energy from time to time. By January 26, 2023, PJM shall report all dates between December 24, 2022, and December 26, 2022, inclusive, on which the Specified Resources were operated, the hours of operation, and exceedance of permitting limits, including sulfur dioxide, nitrogen oxide, mercury, carbon monoxide, and other air pollutants, as well as exceedances of wastewater release limits. PJM shall submit a final report by February 27, 2023, with any revisions to the information reported on January 26, 2023. The environmental information submitted in the final report shall also include the following information:

(i) Emissions data in pounds per hour for each Specified Resource unit, for each hour of the operational scenario, for CO, NOx, PM10, VOC, and SO2;

(ii) Emissions data must include emissions (lbs/hr) calculated consistent with reporting obligations pursuant to operating permits, permitted operating/emission limits, and the actual incremental emissions above the permit limits;

(iii) The number and actual hours each day that each Specified Resource unit operated in excess of permit limits or conditions, e.g., "Generator #1; December 25, 2022; 4 hours; 04:00-08:00 CT";

(iv) Amount, type and formulation of any fuel used by each Specified Resource;

(v) All reporting provided under the Specified Resource's operating permit requirements over the last three years to the United States Environmental Protection Agency or local Air Quality Management District for the location of a Specified Resource that operates pursuant to this Order;

(vi) Additional information requested by DOE as it performs any environmental review relating to the issuance of this Order; and

(vii) Information provided by the Specified Resource describing how the requirements in paragraph C above were met by the Specified Resource while operating under the provisions of this Order.

In addition, PJM shall provide information to the Department quantifying the net revenue in aggregate associated with generation in excess of environmental limits in connection with orders issued by the Department pursuant to Section 202(c) of the Federal Power Act.

F. PJM shall take reasonable measures to inform affected communities where all Specified Resources operate that PJM has been issued this Order, in a manner that ensures that as many members of the community as possible are aware of the Order, and explains clearly what the Order allows PJM to do. At a minimum, PJM shall post a description of this Order on its website (with a link to this Order) and identify the name, municipality or other political subdivision, and zip code of Specified Resources covered by this Order, as the Specified Resources may be updated pursuant to paragraph D above. In addition, in the event that a Specified Resource operates pursuant to this Order, a general description of the action authorized by this Order will be included in any press release issued by PJM with respect to the cold weather event and will include a reference to the website posting required by the preceding sentence for further information. PJM shall describe the actions taken to comply with this paragraph in the reports delivered to the Department pursuant to paragraph E above.

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

H. PJM shall be responsible for the reasonable third-party costs of performing analysis of the environmental and environmental justice impacts of this Order, including any analysis conducted pursuant to the National Environmental Policy Act.

I. This Order shall be effective upon its issuance, and shall expire at 12:00 Eastern Time on Monday, December 26, 2022, with the exception of the reporting requirements in

paragraph E. Renewal of this Order, should it be needed, must be requested before this Order expires.

Issued in Washington, D.C. at 5:30 PM Eastern Standard Time on this 24th day of December 2022.

Undersecretary of Energy for Infrastructure

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. 202-26-46
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	)))))	Order No. 202-26-47

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

Exhibit 10
Grid Strategies June Report

A Review of DOE's 202(c) Order for the Campbell Coal Plant

Michael Goggin

June 18, 2025

I. Executive Summary 2
II. Background on Resource Adequacy Methods 2
II. Existing State and Regional Measures Already Ensure Reliability and Resource Adequacy. 3
A. States and Utilities 4
B. MISO 4
C. NERC 7
III. There Is No Evidence Consumers Energy, Michigan, or MISO Has a Resource Adequacy Emergency this Summer. 8
A. Michigan 9
B. MISO 10
C. NERC's Summer Reliability Assessment Does Not Indicate a Supply Emergency. .. 10
D. The NERC and MISO resource adequacy studies are likely conservative. 11
IV. Consumers Energy May Need to Buy Coal to Comply with DOE's Order. 13
V. Qualifications of Michael Goggin 14
VI. Sources 15

I. Executive Summary

On May 23, 2025, the U.S. Department of Energy ("DOE") issued an order under Section 202(c) of the Federal Power Act directing the Midcontinent Independent System Operator ("MISO") and utility Consumers Energy to take "all measures necessary" to ensure the continued availability of the J.H. Campbell coal power plant in Michigan for three months, past its scheduled retirement date on May 31, 2025.[1] The DOE order claims there is an emergency due to insufficient "dispatchable capacity" in MISO. The order does not define dispatchable capacity and does not clearly indicate the basis on which the Energy Secretary believes there is a shortfall of dispatchable resources. In my experience, "dispatchable" generally refers to generating resources that can change their level of output on command, and a stated lack of "capacity" is a claim that there will be insufficient electricity supply during periods of peak demand, a need often referred to as "resource adequacy."

This report is organized into four sections. First, it provides brief background on the methods grid planners use to ensure electricity supply is adequate to meet demand. Next, it reviews how utilities, state regulators, regional grid operators, and reliability regulators use planning, regulatory, and market mechanisms to ensure electricity generating supply is adequate to meet demand. Third, it reviews the determinations Consumers Energy, Michigan, and MISO have already made that the Campbell plant is not necessary for meeting anticipated electricity demand this summer, in large part because MISO has a summer capacity surplus of more than 2,600 MW. That section also documents why the North American Electric Reliability Corporation ("NERC") Summer Reliability Assessment that DOE cites to justify its order does not indicate that an emergency exists in the MISO region. Finally, the report explains why the aging Campbell plant is a poor choice for meeting electricity demand this summer, as evidenced by its low availability rates during recent summer peak demand periods.

II. Background on Resource Adequacy Methods

At the outset, it is helpful to explain some relevant terms. "Resource adequacy" generally means having enough supply during periods of peak net system need from generators and from other resources like demand response (programs by which electricity users are compensated for reducing consumption) and energy storage.

There is no one correct amount of resource adequacy: what level is appropriate depends in part on what system planners, regulators, industry, utilities, customers, government, and other stakeholders want to pay for. This question is one of risk versus reward. More resources can always be added to achieve more resource adequacy, but there are diminishing returns if more is invested. As a result, the usual benchmark for acceptable risk of such events occurring is one day of lost load in ten years. In other words, system planners typically seek to have a set of

[1] U.S. DOE, *Order No. 202-25-3*, (May 23, 2025) available at https://www.energy.gov/sites/default/files/2025-05/Midcontinent%20Independent%20System%20Operator%20%28MISO%29%20202%28c%29%20Order_1.pdf

resources such that the system can expect to experience no more than one day containing an outage in ten years. Utilities, state regulators, and regional grid operators have coalesced around this benchmark, and have generally concluded that it appropriately balances the cost of building and maintaining generating capacity versus the cost of potential generation shortfalls. Many state regulators use the one day in ten years criterion to ensure profit-maximizing utilities do not burden ratepayers with the cost of excessive generating capacity. This is largely due to the diminishing marginal returns from a higher planning reserve margin,[2] which is the amount of extra generating capacity that exists in a system above peak load projections, expressed as a percentage of peak load.

To calculate the target reserve margin that achieves a specific risk threshold, planners use sophisticated statistical analyses to simulate electricity demand and supply availability scenarios based on decades of historical weather patterns. The reserve margin thus accounts for interannual variability in peak electricity demand due to extreme weather events and other factors. Planners also use these sophisticated methods to determine the expected contribution of each resource towards meeting peak needs, often called a resource's "capacity value" or "accredited capacity." These methods account for how weather patterns affect the timing of wind and solar output, and how unplanned outages and other factors can cause any resource to have reduced availability during periods of need.[3] Thus, planners account for all of these risks in setting the target reserve margin.

II. Existing State and Regional Measures Already Ensure Reliability and Resource Adequacy.

The regulation and oversight of power grid reliability and resource adequacy have become far more sophisticated and robust since Section 202(c) of the FPA was enacted in 1935. For most of the past century, states and the electric utilities they regulate have had front-line responsibility for ensuring that adequate resources are available to serve the electric power needs of customers in their jurisdictions. In recent decades, two key developments have layered regional and national assurance mechanisms onto the existing state resource adequacy regulations.

First, the Federal Energy Regulatory Commission ("FERC") approved the formation of Regional Transmission Organizations ("RTOs") and Independent System Operators ("ISOs"),

---

[2] For example, see K. Carden and A. Dombrowsky, *Estimation of the Market Equilibrium and Economically Optimal Reserve Margins for the ERCOT Region for 2024 (Final)*, (January 2021) available at https://www.ercot.com/files/docs/2021/01/15/2020_ERCOT_Reserve_Margin_Study_Report_FINAL_1-15-2021.pdf, at 34-40; and PJM, *2023 PJM Reserve Requirement Study*, (October 2023) available at https://www.pjm.com/-/media/DotCom/committees-groups/committees/mc/2023/20231115/20231115-consent-agenda-b---2-2023-pjm-reserve-requirement-study-report-final.ashx, at 27.

[3] MISO, *Planning Year 2025-2026 Loss of Load Expectation Study Report*, available at https://cdn.misoenergy.org/PY%202025-2026%20LOLE%20Study%20Report685316.pdf?v=20250313114401, at 20-23.

such as MISO. The RTOs and ISOs operate the bulk power transmission system within their service areas – which in several cases (including MISO) cover multiple states – and manage wholesale electricity markets that help ensure resource adequacy.

Second, Congress enacted Section 215 of the FPA in 2005, creating a new reliability regulatory regime overseen by FERC. Pursuant to Section 215, FERC designated NERC as the national Electric Reliability Organization, with responsibility for setting and enforcing national reliability standards, subject to FERC approval. NERC also designates "Regional Entities" that help implement the national standards in their regions and develop region-specific standards, subject to FERC and NERC approval. ReliabilityFirst Corporation ("RFC") is the Regional Entity for Michigan and most of eastern MISO. Together, state utility regulators, ISOs and RTOs, NERC and its subsidiary regional reliability organizations, and FERC share responsibility for assuring the electric grid operates reliably.

A. States and Utilities

The states are responsible for ensuring that the utilities they regulate have adequate resources to meet demand for electric power. In most states, including Michigan, utility regulators have processes through which they evaluate utilities' plans to add new generators, retire old generators, and undertake a host of other activities, with the goal being to identify a prudent resource plan that minimizes costs and risks for ratepayers. I have participated in many of these "integrated resource plan" or "IRP" proceedings, which are detailed, fact-intensive processes in which the regulator and other stakeholders closely review a utility's proposed assumptions and methods. A primary focus of IRP proceedings is ensuring resource adequacy. State regulators have strong incentives to ensure resource adequacy, as a generation shortfall in a state can result in localized blackouts or increased costs for ratepayers.

B. MISO

MISO plays two important roles in ensuring resource adequacy. First, as discussed further below, MISO is a designated Planning Coordinator responsible for implementing the resource adequacy planning standard adopted by RFC. Pursuant to that standard, MISO performs and documents an annual resource adequacy analysis, which is based on the "one day in ten years" loss of load standard. MISO uses that analysis to determine a planning reserve margin for the region, for each season of the upcoming year. MISO then applies that margin to each zone's load projections to determine the planning reserve margin requirement for each zone and season.

Second, MISO runs a residual capacity market that allows utilities and generators to buy and sell capacity to meet each of their four seasonal planning reserve margin requirements. MISO and other grid operators also use energy markets and other tools to ensure that electricity supply meets demand at all times. Each of these markets is discussed in more detail below.

1. Capacity Market

First, MISO sets the planning reserve margin that it determines is required to meet the "one day in ten years" benchmark, and determines resources' capacity accreditation, as discussed above. MISO then applies the planning reserve margin to each zone of MISO. As part of this, MISO uses power flow models to assess how transmission constraints affect the need for generation in each zone in the MISO region.[4] This ensures that there are sufficient resources to meet demand in each zone, after accounting for the transmission capacity available to import power from other zones.

Based on these inputs and zonal requirements, MISO then conducts an annual capacity market auction, and this price signal provides an additional mechanism to incentivize the development and construction of new generation to help meet future resource adequacy needs. The core elements of MISO's capacity market processes have been approved by FERC under its authority to ensure that rates are just, reasonable, and not unduly discriminatory under Section 205 of the Federal Power Act.[5]

If a utility falls short of its resource adequacy obligation to meet its needs plus MISO's reserve margin, it must make up for that shortfall through purchases in the capacity market. If supply is short or import purchases begin to approach the import limit MISO has calculated for a given zone, the price of capacity in that zone will increase. State regulators are cognizant of that risk, and thus have a strong incentive to ensure their utilities have adequate supplies in advance.

2. Real-Time and Near-Term Operations

Each day MISO runs a day-ahead energy market in which generators offer to produce electricity each hour of the next day at a certain price. MISO then compares this supply curve of offers to its demand forecast for the next day, and then "commits" the generators that can meet this demand forecast at lowest cost subject to reliability and transmission constraints. Generators that are committed but were offline start and take other steps required to be online by the next day. The vast majority of electricity is procured in the day-ahead market, but MISO also runs a real-time energy market to fine-tune deviations in supply and demand that occur after the day-ahead market has concluded. The energy markets play an important role in ensuring supply is adequate to meet demand by sending a powerful price signal for generators to maximize their output and for utilities to import power from neighboring regions during periods of need.

MISO also operates "ancillary services" markets, which procure other services like operating reserves from flexible resources that help balance fast variability in supply and demand. Prices in these markets are typically very low as MISO has a large supply of flexible

[4] *Id.* at 36-55.
[5] FERC Docket Nos. 11-4081; EL15-70 *et al.*; ER22-495; ER23-2977; ER24-1638.

resources,[6] and that supply is increasing as batteries and other flexible resources replace inflexible coal and nuclear generators.

As a result, there is no indication of a need for "dispatchable" resources, as claimed by DOE's Order, to provide additional flexibility in MISO. If a need for more flexibility arose at any point in time, prices for ancillary services would simply increase, spurring flexible generators that were offline to start up and provide flexibility until the need has passed. Regardless, coal plants like Campbell are not very dispatchable compared to other generating resources, with long startup times, slow output ramp rates, and high minimum output levels. This can also reduce their capacity contribution to meeting peak demand needs, particularly those that arise on short notice.

If MISO encounters a risk of a generation shortage in real-time operations, it has numerous additional tools that it can deploy in a stepwise fashion to help ensure supply is adequate to meet demand.[7] The impact of many of these steps is not fully accounted for in MISO's loss of load analysis, making that planning conservative.

Days in advance of expected extreme heat, cold, or other severe weather, MISO can issue an alert or declare Conservative System Operations, directing transmission and generating resources on planned outages to return to service and make other preparations.[8] NERC notes this step helped ensure resource adequacy in MISO last summer.[9] As noted below, NERC's "elevated risk" designation for MISO is based on the assumption that many generators are on outage, so by taking steps to reduce generator outages MISO can reduce that risk.

Next, MISO can progress to issuing a capacity warning, which activates numerous additional steps to increase supply, including activating emergency pricing, and curtailing non-firm exports.[10] If the event then progresses to step 1a, MISO activates demand response resources, which are customers that are compensated for reducing their demand during periods of need. If an event progresses to step 1b, generating units are directed to operate at their

---

[6] Potomac Economics, 2023 State of the Market Report for the MISO Electricity Markets, (June 2024) available at https://www.potomaceconomics.com/wp-content/uploads/2024/06/2023-MISO-SOM_Report_Body-Final.pdf, at 8-9.

[7] MISO, *MISO Market Capacity Emergency*, available at https://cdn.misoenergy.org/SO-P-EOP-11-002%20Rev%2021%20MISO%20Market%20Capacity%20Emergency683501.pdf, at 37-39.

[8] MISO, *Conservative System Operations*, available at https://cdn misoenergy.org/SO-P-NOP-00-449%20Rev%2010%20Conservative%20System%20Operations688847.pdf

[9] NERC, *2025 Summer Reliability Assessment*, (May 2025) available at https://www nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf, at 51, referring to summer 2024: "MISO experienced peak electricity demand during late August. Demand was between the normal and 90/10 summer peak forecast levels. Wind and solar resource output at the time of peak demand were near expectations for summer on-peak contributions. Forced outages of thermal units, however, were lower than expected. On the day prior to MISO's peak demand, operators issued advisories to maximize generation. Similar advisories were issued earlier in the summer, coinciding with above-normal temperatures and periods of high generator forced outages."

[10] MISO, *MISO Market Capacity Emergency*, available at https://cdn.misoenergy.org/SO-P-EOP-11-002%20Rev%2021%20MISO%20Market%20Capacity%20Emergency683501.pdf, at 10-12.

emergency maximum limits. If the event escalates further, MISO can then progress through additional steps including activating additional tiers of demand response resources, issuing public conservation requests, procuring emergency energy, and directing resources with environmental de-rates to request waivers, all before load is shed.[11]

C. NERC

Pursuant to Section 215 of the Federal Power Act, FERC certified NERC as the Electric Reliability Organization responsible for developing mandatory reliability standards, subject to FERC's review and approval. NERC also annually assesses seasonal and long-term reliability of the bulk power system and monitors system performance.

1. Mandatory Reliability Standards

NERC Regional Entity RFC has imposed a mandatory standard for Planning Resource Adequacy Analysis, Assessment, and Documentation for the region that includes Michigan. As the Planning Coordinator for Michigan, MISO is required to annually calculate the planning reserve margin required to meet the one day in ten years benchmark.[12] The standard also requires certain methods for the load forecast and the capacity accreditation for resources and imports.

Like other NERC and Regional Entity standards, this requirement is enforceable with fines of up to $1 million per day per violation. This further ensures MISO conducts robust and standardized resource adequacy planning, and each year MISO extensively documents that its planning methods fully meet this standard.[13]

2. Reliability Assessments

NERC also conducts periodic assessments of reliability in the country, including a summer, winter, and long-term reliability assessment every year. In the seasonal assessments, NERC groups regions into three categories for risk of resource adequacy shortfalls, as shown in the NERC figure below.[14] MISO's categorization as "elevated" risk in this year's NERC Summer Reliability Assessment is the middle of three risk categories, below "high" and above

---

[11] *Id.* at 38-39.
[12] NERC, *Standard BAL-502-RFC-02*, available at https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-502-RFC-02.pdf
[13] *See, e.g.*, MISO, *Planning Year 2025-2026 Loss of Load Expectation Study Report*, available at https://cdn.misoenergy.org/PY%202025-2026%20LOLE%20Study%20Report685316.pdf?v=20250313114401, at 56-60.
[14] NERC, *2025 Summer Reliability Assessment*, (May 2025) available at https://www nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf, at 10.

"normal." In its 2023[15] and 2024[16] Summer Reliability Assessments, NERC respectively identified 8 and 5 out of 13 U.S. regions as having elevated risk. Despite half of U.S. regions being designated as having elevated risk, there were no resource adequacy shortfalls in either summer.

Table 1: Seasonal Risk Assessment Summary

Category	Criteria[1]
High Potential for insufficient operating reserves in normal peak conditions	• Planning Reserve Margins do not meet Reference Margin Levels; or • Probabilistic indices exceed benchmarks (e.g., LOLH of 2.4 hours over the season); or • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under **normal peak-day demand and outage scenarios**[2]
Elevated Potential for insufficient operating reserves in above-normal conditions	• Probabilistic indices are low but not negligible (e.g., LOLH above 0.1 hours over the season); or • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under **extreme peak-day demand with normal resource scenarios** (i.e., typical or expected outage and derate scenarios for conditions);[2] or • Analysis of the risk hour(s) indicates resources will not be sufficient to meet operating reserves under **normal peak-day demand with reduced resources** (i.e., extreme outage and derate scenarios)[3]
Normal Sufficient operating reserves expected	• Probabilistic indices are negligible • Analysis of the risk hour(s) indicates resources will be sufficient to meet operating reserves under normal and extreme peak-day demand and outage scenarios[4]

Table Notes:
[1]The table provides general criteria. Other factors may influence a higher or lower risk assessment.
[2]**Normal resource scenarios** include planned and typical forced outages as well as outages and derates that are closely correlated to the extreme peak demand.
[3]**Reduced resource scenarios** include planned and typical forced outages and low-likelihood resource scenarios, such as extreme low-wind scenarios, low-hydro scenarios during drought years, or high thermal outages when such a scenario is warranted.
[4]Even in normal risk assessment areas, extreme demand and extreme outage scenarios that are not closely linked may indicate risk of operating reserve shortfall.

Figure 1: NERC table showing categories used for regions' seasonal risk

III. There Is No Evidence Consumers Energy, Michigan, or MISO Has a Resource Adequacy Emergency this Summer.

Michigan utility regulators and Consumers Energy have determined that Campbell was not needed to meet resource adequacy needs, a conclusion confirmed by MISO's resource adequacy analysis and capacity market results showing a capacity surplus for this summer. Moreover, NERC's Summer Reliability Assessment does not indicate MISO has a supply emergency.

[15] NERC, *2023 Summer Reliability Assessment*, (May 2023) available at https://www nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2023.pdf, at 6.
[16] NERC, *2024 Summer Reliability Assessment*, (May 2024) available at https://www nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2024.pdf, at 6.

A. Michigan

Consumers Energy completed comprehensive reliability and economic modeling in its 2021 IRP, overseen by the Michigan Public Service Commission with robust engagement from stakeholders. As explained above, a cornerstone of this and all IRPs is ensuring resource adequacy needs are met. The utility,[17] the Commission,[18] and other stakeholders concluded that it was more economic and reliable to replace Campbell with a variety of other resources, including by (1) acquiring the nearby 1,200 MW gas-fired Covert Generating Station, which Consumers Energy subsequently purchased in May 2023, and (2) adding nearly 1,600 MW of demand response and energy efficiency by 2025.[19]

Michigan utilities are also bound by the state's Public Act 341 of 2016, which requires them to demonstrate to the Michigan Public Service Commission that they have sufficient generating capacity to meet their capacity obligations. The Commission can impose a state reliability mechanism capacity charge on utilities that fail to meet that requirement. In June 2022, the Commission approved Consumers Energy's demonstration for the 2025/2026 planning year,[20] and more recently Consumers successfully made this demonstration for the 2027/2028 planning year[21] and filed its demonstration for 2028/2029.[22]

Confirming that state and regional officials stand by their determination that the Campbell plant is not needed, the Chair of the Michigan Public Service Commission recently indicated that MISO, Michigan, and Consumers Energy did not ask to keep the Campbell plant online.[23]

---

[17] CMS Energy, *Integrated Resource Plan*, (June 2021) available at https://s26.q4cdn.com/888045447/files/doc_presentations/2021/06/2021-Integrated-Resource-Plan.pdf

[18] Michigan Public Service Commission, *Exhibit A: Settlement Agreement*, https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y000003KjSDAA0 (beginning at page 98 in the pdf)

[19] *Id.* at 4 (101 in the pdf).

[20] See the discussion of Case No. U-21099 at Michigan Public Service Commission, *MPSC approves Consumers Energy integrated resource plan settlement agreement, takes additional steps to boost electric capacity*, (June 2022) available at https://www.michigan.gov/mpsc/commission/news-releases/2022/06/23/mpsc-approves-consumers-irp_takes-steps-improve-capacity

[21] Michigan Public Service Commission, *Order*, Case Nos. U-21393 and U-21775, (August 2024) available at https://mi-psc my.site.com/sfc/servlet.shepherd/version/download/068cs000005gPyUAAU

[22] Consumers Energy, *Redacted Version of Consumers Energy Company's Capacity Demonstration for Planning Year 2028/2029*, (February 2025) available at https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/068cs00000bz8crAAA

[23] C. Brown and H. Stevens, *Coal and Gas Plants Were Closing. Then Trump Ordered Them to Keep Running*, (June 2025) available at https://www nytimes.com/2025/06/06/climate/trump-coal-gas-plants-energy-emergency html

B. MISO

Based on the loss of load analysis discussed above, MISO has concluded that it has "surplus capacity" for this summer, without Campbell.[24] The 2025/26 capacity auction yielded summer capacity supplies 2,623 MW or 2.2 percentage points above the summer reserve margin target of 7.9%, which was calibrated to meet the one day in ten years loss of load benchmark.[25] In other words, MISO would still meet this stringent reliability benchmark this summer even if an additional 2,623 MW of additional capacity unexpectedly were unavailable, and retaining Campbell would only increase MISO's already-generous capacity surplus for this summer beyond 4 GW. As noted above, capacity supply above the reserve margin target provides diminishing marginal returns.

The zonal results from MISO's 2025/26 capacity auction also confirm there is no resource adequacy shortfall this summer in Zone 7, which is the MISO footprint in Michigan's Lower Peninsula. Zone 7 has 1.2 GW of supplies above the summer Local Clearing Requirement, which is the amount of capacity that MISO has concluded must come from within Zone 7 after accounting for transmission constraints.[26]

C. NERC's Summer Reliability Assessment Does Not Indicate a Supply Emergency.

The NERC Summer Reliability Assessment that DOE cites in an attempt to justify the Campbell 202(c) order is based on information reported by MISO and other regional grid operators. Thus, the NERC assessment does not contradict MISO's conclusion that it has a capacity surplus above what it needs to meet its reliability target. In fact, NERC notes that for MISO, "Expectations for load loss and unserved energy are less than these amounts because MISO's resources are above the Reference Margin Level," which is MISO's reserve margin target calibrated to achieve a loss of load risk of one day in 10 years.[27]

NERC including MISO in the "elevated" summer risk category does not indicate a supply emergency. This year's Summer Reliability Assessment identifies four U.S. regions as having elevated risk, plus one region each in Canada and Mexico. As noted above, across the 2023 and 2024 Summer Reliability Assessments NERC identified half of U.S. regions as having elevated risk, yet there were no resource adequacy shortfalls in either summer.

This year's Summer Reliability Assessment finds that MISO has a 24.7% reserve margin, which NERC calculates corresponds to a 9.3% reserve margin with typical generator outage

---

[24] MISO, *Planning Resource Auction Results for Planning Year 2025-26 (Corrections, reposted 05/29/25)*, available at https://cdn misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf at 4.
[25] *Id.* at 3, 4, 37.
[26] *Id.* at 18.
[27] NERC, *2025 Summer Reliability Assessment*, (May 2025) available at https://www nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf, at 12.

rates. NERC's finding of elevated risk only indicates a "Potential for insufficient operating reserves in above-normal conditions."[28] NERC finds that MISO would only see a generation shortfall with a perfect storm of 90th percentile demand (*i.e.*, demand is higher than expected in 9 out of 10 years) at the same time that MISO sees its highest historical rate for generator outages and derates due to "extreme conditions," and even in that worst case scenario it would only have a 1.9% shortfall.[29] By way of comparison, NERC's 2023 and 2024 Summer Reliability Assessments projected MISO would have a 6.9% and 6.3% shortfall under that worst case scenario, respectively, yet NERC still did not designate the risk as "high," and MISO ultimately had more than adequate supplies in both summers.

As explained above, MISO and utility reserve margins are already designed to accommodate wide interannual variability in electricity demand and generator outages, and MISO has calibrated its summer reserve margin to the stringent requirement that it only experience one day of shortfall in 10 years. Moreover, NERC notes that Michigan and the rest of MISO have the lowest risk of any region for seeing above average temperatures this summer.[30]

D. The NERC and MISO resource adequacy studies are likely conservative.

NERC's Summer Reliability Assessment and MISO's loss of load analysis both use conservative assumptions for the availability of imports and renewable output in MISO.

NERC's analysis does not fully account for MISO's ability to import power during periods of need, even though MISO successfully tapped into the supply and demand diversity provided by its neighbors to import more than 13 GW during Winter Storm Uri[31] and 4.5 GW during Winter Storm Elliott.[32] Other studies have documented significant diversity between MISO and its neighbors in the timing of peak demand, lulls in renewable output, and correlated thermal generator outage and derate events, including summer heat waves.[33] These geographic diversity benefits are due to inherent climate and weather diversity, and the fact that extreme heat and cold events are only at their most severe in small geographic areas that move over the course of an event.

---

[28] *Id.* at 6.
[29] *Id.* at 10, 16.
[30] *Id.* at 9.
[31] M. Goggin, *Transmission Makes the Power System Resilient to Extreme Weather*, (July 2021) available at https://gridstrategiesllc.com/wp-content/uploads/2024/05/transmission-makes-the-power-system-resilient-to-extreme-weather.pdf, at 7.
[32] M. Goggin and Z. Zimmerman, *The Value of Transmission During Winter Storm Elliott*, (February 2023) available at https://acore.org/wp-content/uploads/2023/02/The-Value-of-Transmission-During-Winter-Storm-Elliott-ACORE.pdf
[33] A. Brooks, A. Silverstein, and R. Gramlich, *Resource Adequacy Value of Interregional Transmission*, (June 2025) available at https://gridstrategiesllc.com/wp-content/uploads/GridStrategies_RAValueInterregionalTx_250601.pdf; M. Goggin, Z. Zimmerman, and A. Sherman, *Quantifying a Minimum Interregional Transfer Capability Requirement*, (May 2023) available at https://gridstrategiesllc.com/wp-content/uploads/2023/05/GS_Interregional-Transfer-Requirement-Analysis-final54.pdf

DOE's National Transmission Planning Study documented the geographic diversity phenomenon with a compelling set of maps.[34] Those maps show that during the event when MISO saw the highest demand in the period 2007-2013, the Southwest Power Pool and the Southeast had significantly lower demand. Similar maps in the study show significant diversity in when MISO and its neighbors experience lulls in wind or solar output.[35]

NERC has previously noted that "MISO benefits from significant transfer capacity with neighboring assessment areas…"[36] Data in NERC's 2025 Summer Reliability Assessment documents that these neighboring grid operators have large reserve margin surpluses this summer, which further increases the availability of imports from those regions. NERC projects the summer reserve margin surplus under typical generator outage rates for the Southwest Power Pool at 18.2%, Ontario at 23.4%, PJM at 15.0%, the SERC Central region at 12.7%, and Manitoba at 11.2%.[37] As a result, at least some of those regions are highly likely to have surplus generating resources if MISO experiences periods of high demand or low supply this summer.

When calculating the reserve margin needed to meet the 1 day in 10 year target, MISO's loss of load study also makes conservative assumptions for the availability of imports from other regions. While MISO conducts robust statistical modeling of historical import availability, this analysis is conservative because hours in which MISO was exporting or minimally importing due to a lack of need are included in the dataset, even though MISO likely could have imported or at least reduced exports in those hours if needed.[38]

If there were a true resource adequacy emergency in MISO, a potential solution would be to issue a Section 202(c) order to facilitate interchange with neighboring grid operators. As the MISO independent market monitor[39] and others[40] have documented, inefficient pricing of market transactions along MISO's seams with neighboring grid operators can interfere with the efficient flow of power during shortage events. DOE could work with MISO and other stakeholders to improve the efficient flow of power across MISO's seams, improving the availability of imports during periods of peak need.

---

[34] DOE, *National Transmission Planning Study: Chapter 2*, (October 2024) available at https://www.energy.gov/sites/default/files/2024-10/NationalTransmissionPlanningStudy-Chapter2.pdf, at 53.
[35] *Id.* at 51 and 52.
[36] NERC, *2024 Long Term Reliability Assessment,* (December 2024) available at https://www nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf, at 44.
[37] NERC, *2025 Summer Reliability Assessment*, (May 2025) available at https://www nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf, at 10.
[38] MISO, *Planning Year 2025-2026 Loss of Load Expectation Study Report*, available at https://cdn.misoenergy.org/PY%202025-2026%20LOLE%20Study%20Report685316.pdf?v=20250313114401, at 33.
[39] Potomac Economics, *2023 State of the Market Report*, (June 2024) available at https://cdn.misoenergy.org/2023%20State%20of%20the%20Market%20Report636641.pdf, at xiv-xv.
[40] J. Pfeifenberger and N. Bay, *Intertie Optimization: Efficient Use of Interregional Transmission (Update)*, (April 2024) available at https://www.brattle.com/wp-content/uploads/2024/04/Intertie-Optimization-Efficient-Use-of-Interregional-Transmission-Update.pdf

If DOE's claim of resource adequacy risk in MISO were true, facilitating interchange with neighboring grid operators would be more appropriately tailored to address the risk. This is because loss of load probability is concentrated into a narrow slice of hours on a small number of days when high demand coincides with low supply. Increased interchange can occur during just those hours, tapping into diversity in the timing of peak need between MISO and its neighbors. In contrast, retaining the Campbell coal plant for the entire summer is not well-tailored for meeting DOE's claimed emergency.[41]

MISO and NERC also appear not to have accounted for the fact that low wind speed events are negatively correlated with low solar output events. For example, wind speeds tend to be low during high pressure heat dome events, which tend to cause high solar output because there are fewer clouds during such events. Conversely, stormy conditions that result in reduced solar output due to clouds tend to be correlated with high wind output. As NERC notes, MISO has over 31 GW of wind and 18 GW of solar, so one resource can make up for shortfalls of the other.[42] As noted above, there is also significant diversity in when MISO and its neighboring regions experience lulls in renewable output. MISO meteorologists have also "projected normal to above-normal wind generation" for this summer.[43]

IV. Consumers Energy May Need to Buy Coal to Comply with DOE's Order.

The DOE data shown below indicate that coal supplies at the plant appear to have been drawn down in advance of its anticipated retirement, with enough coal remaining onsite as of the end of March 2025 to operate the plant for only about two to three weeks.[44] The DOE data indicate the plant is supplied via rail deliveries from a coal mine in Wyoming.[45]

---

[41] As DOE's Campbell order notes, "FPA section 202(c) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law and minimize any adverse environmental impacts." U.S. DOE, *Order No. 202-25-3*, (May 23, 2025) https://www.energy.gov/sites/default/files/2025-05/Midcontinent%20Independent%20System%20Operator%20%28MISO%29%20202%28c%29%20Order_1.pdf, at 2.

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

[43] MISO, *2025 Summer Readiness Workshop*, (May 2025) available at https://cdn.misoenergy.org/20250508%20Summer%20Readiness%20Workshop%20Items%2002-04%20Presentation695282.pdf, at 17.

[44] DOE Energy Information Administration, *EIA-923 March 2025*, (May 2025) available at https://www.eia.gov/electricity/data/eia923/, with monthly stocks calculated by taking coal stock data as of December 2023 and then subtracting monthly consumption and adding monthly deliveries.

[45] *Id.*

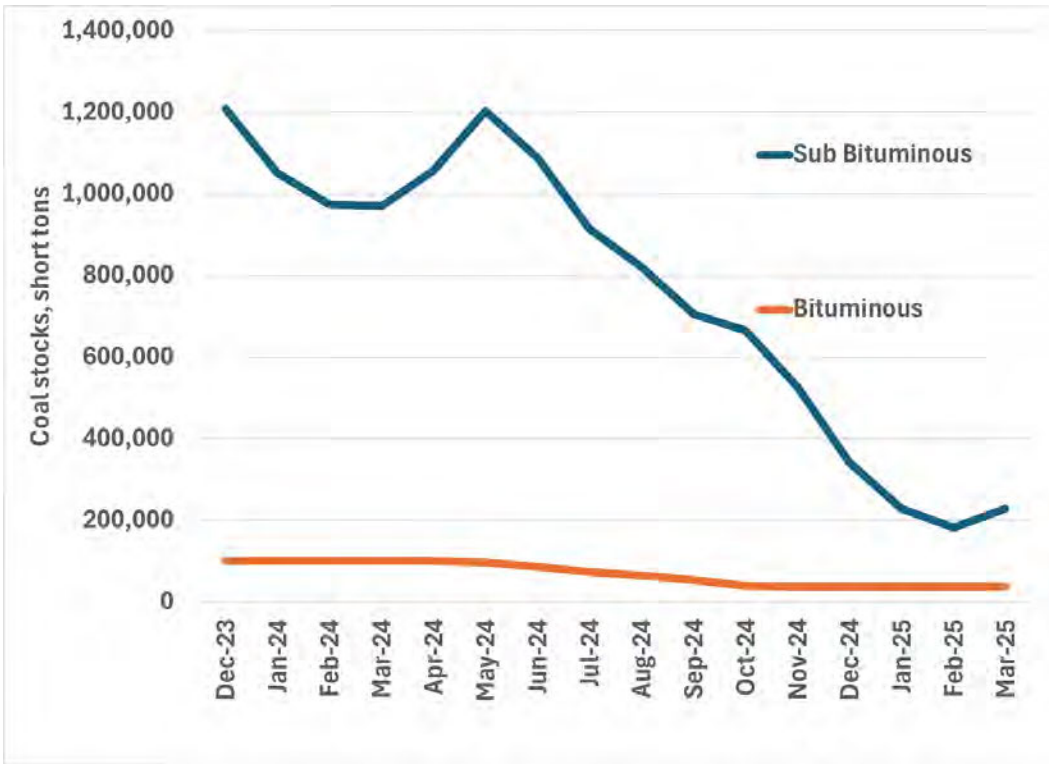


Figure 2: Coal supplies at Campbell, per DOE data

V. Qualifications of Michael Goggin

Michael Goggin has worked on electricity market and reliability issues for over 20 years. At Grid Strategies he serves as an expert on those topics for a range of clients including state utility regulators, grid operators, and non-profit organizations. He has testified as an expert in dozens of proceedings before state utility commissions in Arizona, Colorado, Georgia, Iowa, Illinois, Indiana, Wisconsin, Louisiana, Michigan, Minnesota, Missouri, Montana, Nevada, New Mexico, North Carolina, Ohio, Oklahoma, South Carolina, Virginia, Washington, and Wisconsin, as well as before FERC.

For the preceding ten years Michael worked at the American Wind Energy Association (now known as the American Clean Power Association), where he provided technical analysis regarding renewable energy, transmission, and wholesale electricity markets, including directing the organization's research and analysis team from 2014-2018. Prior to the American Wind Energy Association, he worked at a firm serving as a consultant to DOE, and at two environmental groups.

In the course of that work, Michael has co-authored more than one hundred filings to FERC; served as a technical reviewer for over a dozen national laboratory reports, academic articles, and renewable integration studies; published academic articles and conference presentations on renewable integration, transmission, and policy; and been elected to the Standards, Operating, and Planning Committees of NERC. He graduated with honors from Harvard University. His recent publications are available at https://gridstrategiesllc.com/reports/.

VI. Sources

The principal documents I relied on in preparing this report include the materials listed below and in footnotes. To the extent feasible, relevant documents are included in the Appendix of the Request for Rehearing.

-MISO, *Planning Year 2025-2026 Loss of Load Expectation Study Report*, available at https://cdn.misoenergy.org/PY%202025-2026%20LOLE%20Study%20Report685316.pdf?v=20250313114401

-MISO, *Planning Resource Auction Results for Planning Year 2025-26 (Corrections, reposted 05/29/25)*, available at https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf

-MISO, *MISO Market Capacity Emergency*, available at https://cdn.misoenergy.org/SO-P-EOP-11-002%20Rev%2021%20MISO%20Market%20Capacity%20Emergency683501.pdf

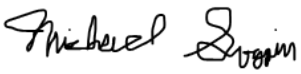
-U.S. EPA, *Continuous Emission Monitoring Systems: Custom Data Download*, available at https://campd.epa.gov/data/custom-data-download

-NERC, *Standard BAL-502-RFC-02*, available at https://www.nerc.com/pa/Stand/Reliability%20Standards/BAL-502-RFC-02.pdf

-NERC, *2025 Summer Reliability Assessment*, (May 2025) available at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_SRA_2025.pdf

-Michigan Public Service Commission, *Exhibit A: Settlement Agreement*, https://mi-psc.my.site.com/sfc/servlet.shepherd/version/download/0688y000003KjSDAA0 (beginning at page 98 in the pdf)

DOE Energy Information Administration, *EIA-923 March 2025*, (May 2025) available at https://www.eia.gov/electricity/data/eia923/



Michael Goggin
Vice President
Grid Strategies, LLC

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. 202-26-46
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	)))))	Order No. 202-26-47

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

Exhibit 11
NIPSCO 2025 Planning Reserve Margin Report

STATE OF INDIANA

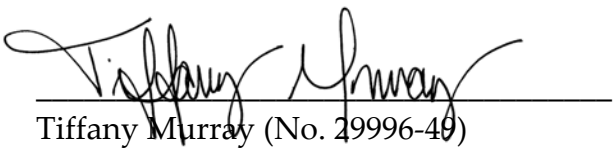
INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC FOR DETERMINATION THAT CERTAIN INFORMATION CONTAINED IN ITS REPORT TO BE SUBMITTED TO THE COMMISSION PURSUANT TO IND. CODE § 8-1-8.5-13 IS CONFIDENTIAL AND EXEMPT FROM DISCLOSURE PURSUANT TO 170 IAC 1-1.1-4, IND. CODE § 8-1-2-29 AND IND. CODE § 5-14-3-4.	)	**CAUSE NO. 46233**

PETITIONER'S SUBMISSION OF REDACTED REPORTS

Northern Indiana Public Service Company LLC, by counsel, respectfully submits the attached redacted reports filed pursuant to Ind. Code § 8-1-8.5-13.

Respectfully submitted,



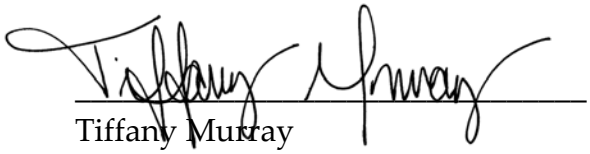
Tiffany Murray (No. 29996-49)
NiSource Corporate Service – Legal
150 W. Market Street, Suite 600
Indianapolis, Indiana 46204
Phone: 317.649-6424
Fax: 317.684.4918
Email: tiffanymurray@nisource.com

Attorney for Petitioner
Northern Indiana Public Service Company LLC

CERTIFICATE OF SERVICE

The undersigned hereby certifies that the foregoing was served via email transmission upon Carol Sparks Drake, Office of Utility Consumer Counselor, 115 W. Washington Street, Suite 1500 South, Indianapolis, Indiana 46204 (cadrake@oucc.in.gov, infomgt@oucc.in.gov).

Dated this 1st day of May, 2025.



Tiffany Murray

IC 8-1-8.5-13(i) Reporting Form - Planning Resource Year 1 (2025 to 2026)

Indiana Utility Regulatory Commission

Add rows below as necessary. For resources located outside of Zone 6, please provide a description of the deliverability arrangements.
For demand response resources, please provide a description of each program.

Owned Resource *IC 8-1-8.5-13(i)(1) definition*	**ICAP (MW)** *Nameplate capacity*	**Summer UCAP (MW)** *IC 8-1-8.5-13(f) definition*	**Fall UCAP (MW)** *IC 8-1-8.5-13(f) definition*	**Winter UCAP (MW)** *IC 8-1-8.5-13(g) definition*	**Spring UCAP (MW)** *IC 8-1-8.5-13(f) definition*	**Location:** *RTO interconnection zone*	**Fuel Source**	**Additional Comments**
CIN.SUCRKGT1	175	146.4	144.4	133.7	170.7	Zone 6	Gas	This is one combined asset.
CIN.SUCRKGT2	175	145.6	145.1	162.6	170.8	Zone 6	Gas	
CIN.SUCRKST1	228	202.4	192.1	181	223.1	Zone 6	Waste Heat	
NIPS.MICHCP12	469	313.4	311.5	170.9	317.6	Zone 6	Coal	
NIPS.NORWAPNOR	4	1.6	0.9	2.2	3.4	Zone 6	Water	
NIPS.OAKDAPOAK	6				4.6	Zone 6	Water	Planned outage until February 2026
NIPS.ROSEWRWF	100.1	20.2	25.7	23.8	26.8	Zone 6	Wind	This is a tax equity joint venture w/ NIPSCO as controlling member
NIPS.INCROSWF	300.1	55.5	46.8	67.3	62.8	Zone 6	Wind	This is a tax equity joint venture w/ NIPSCO as controlling member
NIPS.SCHAHP16A	78	44.3	58.6	35.4	39.7	Zone 6	Gas	
NIPS.SCHAHP16B	77	63.4	70.6	77.1	68.4	Zone 6	Gas	
NIPS.SCHAHP17	361	199.7	245.9			Zone 6	Coal	Plan to retire end of 2025
NIPS.SCHAHP18	361	295.6	271			Zone 6	Coal	Plan to retire end of 2025
NIPS.DUNNBR1SF	265	181.7	109.2	3.2	154.3	Zone 6	Solar	This is a tax equity joint venture w/ NIPSCO as controlling member.
NIPS.INCRMLSP	200	131.4	85.7	1.6	108.2	Zone 6	Solar	This is a tax equity joint venture w/ NIPSCO as controlling member.
Dunns II	435	217.5	217.5	21.8	217.5	Zone 6	Solar	
Dunns II Battery	56.25	53.5	53.5	53.5	53.5	Zone 6	Battery	
Fairbank	250	125	125	12.5	125	Zone 6	Solar	
Gibson	200		100	10	100	Zone 6	Solar	
Calvary	200	109	77.5	7.8	77.5	Zone 6	Solar	
Calvary Battery	45	45	42.8	42.8	42.8	Zone 6	Battery	

Contracted Resource *IC 8-1-8.5-13(i)(2) definition*	**ICAP (MW)** *Nameplate capacity*	**Summer UCAP (MW)** *IC 8-1-8.5-13(f) definition*	**Fall UCAP (MW)** *IC 8-1-8.5-13(f) definition*	**Winter UCAP (MW)** *IC 8-1-8.5-13(g) definition*	**Spring UCAP (MW)** *IC 8-1-8.5-13(f) definition*	**Location:** *RTO interconnection zone*	**Fuel Source**	**Additional Comments**
[redacted]								
								Capacity from external resource zone
								Capacity from external resource zone
								Capacity from external resource zone
								Capacity from external resource zone
								Capacity from external resource zone
								Capacity from external resource zone
								Capacity from external resource zone

Demand Response Resource *IC 8-1-8.5-13(i)(3) definition*	**Summer UCAP (MW)** *IC 8-1-8.5-13(f) definition*	**Fall UCAP (MW)** *IC 8-1-8.5-13(g) definition*	**Winter UCAP (MW)** *IC 8-1-8.5-13(g) definition*	**Spring UCAP (MW)** *IC 8-1-8.5-13(g) definition*	**Additional Comments**
					Please see below, where NIPSCO has broken this out to account for Rate 831 Tier 2 and 3.

NIPSCO 531 Tier 2 & 3 Customers Contracted Resource	**Summer UCAP (ZRC)**	**Fall UCAP (ZRC)**	**Winter UCAP (ZRC)**	**Spring UCAP (ZRC)**	**Additional Comments**
A	0	0	0	0	Load Purchase Capacity (ZRC) by Customer
B	0	0	0	0	Load Purchase Capacity (ZRC)
C	169.9	121.6	176.5	199.1	Load Purchase Capacity (ZRC) by Customer
D	0	0	0	0	Load Purchase Capacity (ZRC) by Customer
E	0	0	0	0	Load Purchase Capacity (ZRC) by Customer
F	0	0	0	0	Load Purchase Capacity (ZRC) by Customer
G	0	0	0	0	Load Purchase Capacity (ZRC) by Customer

NIPSCO 531 Tier 2 & 3 Customers Load Modiying Resource	Summer Registered As LMR @ MISO (ZRC) (MW X (1+PRM) X (1+TL))	Fall Registered As LMR @ MISO (ZRC) (MW X (1+PRM) X (1+TL))	Winter Registered As LMR @ MISO (ZRC) (MW X (1+PRM) X (1+TL))	Spring Registered As LMR @ MISO (ZRC) (MW X (1+PRM) X (1+TL))	Additional Comments
A	198.9	176.3	164.0	209.0	Registered as LMR @ MISO by NIPSCO
B	0.0	0.0	0.0	0.0	Registered as LMR @ MISO by NIPSCO
C	0.0	0.0	0.0	0.0	Registered as LMR @ MISO by NIPSCO
D	79.7	84.0	86.8	89.1	Registered as LMR @ MISO by NIPSCO
E	0.0	0.0	0.0	0.0	Registered as LMR @ MISO by NIPSCO
F	152.0	170.6	186.4	189.5	Registered as LMR @ MISO by NIPSCO
G	185.9	198.9	186.2	229.8	Registered as LMR @ MISO by NIPSCO

		This minus Rate 531 Tier 2 & 3 Customers	This with Rate 531 Tier 2 & 3 Customers	Additional Comments
RTO established Planning Reserve Margin requirement *(see IC 8-1-8.5-13 (i)(4)*	Summer Demand ___ MWx(1+ % PRM ____) = ____MW	2600.1	3479.6	w/ TL of 2.5% PRMR of 7.9%

NIPSCO has peformed this calculation without Rate 531 Tier 2 and 3 customers (column D) and with those customers (column E)

Fall Demand ___ MWx(1+ % PRM ____) = ____MW	This minus Rate 531 Tier 2 & 3 Customers	This with Rate 531 Tier 2 & 3 Customers	Additional Comments
	2467.6	3408.6	w/ TL of 3.8% PRMR of 14.9%

Winter Demand ___ MWx(1+ % PRM ____) = ____MW	This minus Rate 531 Tier 2 & 3 Customers	This with Rate 531 Tier 2 & 3 Customers	Additional Comments
	1941.9	2897.5	w/ TL of 1.7% PRMR of 18.4%

Spring Demand ___ MWx(1+ % PRM ____) = ____MW	This minus Rate 531 Tier 2 & 3 Customers	This with Rate 531 Tier 2 & 3 Customers	Additional Comments
	2415.4	3472.2	w/ TL of 3.4% PRMR of 25.3%

Please describe any other federal reliability requirement:	

Reliability Adequacy Metrics *[defined in IC 8-1-8.5-13(e)]*			
Summer RA Metric *IC 8-1-8.5-13(e)(1)*	**Fall RA Metric** *IC 8-1-8.5-13(e)(2)*	**Winter RA Metric** *IC 8-1-8.5-13(e)(2)*	**Spring RA Metric** *IC 8-1-8.5-13(e)(2)*
Summer UCAP/PRM Requirement = ____%	Fall UCAP/PRM Requirement = ____%	Winter UCAP/PRM Requirement = ____%	Spring UCAP/PRM Requirement = ____%

NIPSCO has peformed this calculation (below) without Rate 531 Tier 2 and 3 customers (columns B and C) and with those customers (column D and E)

This minus Rate 531 Tier 2 & 3 Customers				This with Rate 531 Tier 2 & 3 Customers			
Summer UCAP	Fall UCAP	Winter UCAP	Spring UCAP	Summer UCAP	Fall UCAP	Winter UCAP	Spring UCAP
[redacted]							
Summer RA Metric	Fall RA Metric	Winter RA Metric	Spring RA Metric	Summer RA Metric	Fall RA Metric	Winter RA Metric	Spring RA Metric
[redacted]							

IC 8-1-8.5-13(i) Reporting Form - Planning Resource Year 2 (2026 to 2027)

Indiana Utility Regulatory Commission

Add rows below as necessary. For resources located outside of Zone 6, please provide a description of the deliverability arrangements.
For demand response resources, please provide a description of each program.

Owned Resource *IC 8-1-8.5-13(i)(1) definition*	**ICAP (MW)** *Nameplate capacity*	**Summer UCAP (MW)** *IC 8-1-8.5-13(f) definition*	**Fall UCAP (MW)** *IC 8-1-8.5-13(f) definition*	**Winter UCAP (MW)** *IC 8-1-8.5-13(g) definition*	**Spring UCAP (MW)** *IC 8-1-8.5-13(f) definition*	**Location:** *RTO interconnection zone*	**Fuel Source**	**Additional Comments**
CIN.SUCRKGT1	175	146.4	144.4	133.7	170.7	Zone 6	Gas	This is one combined asset.
CIN.SUCRKGT2	175	145.6	145.1	162.6	170.8	Zone 6	Gas	
CIN.SUCRKST1	228	202.4	192.1	181	223.1	Zone 6	Waste Heat	
NIPS.MICHCP12	469	313.4	311.5	170.9	317.6	Zone 6	Coal	
NIPS.NORWAPNOR	4	1.6	0.9	2.2	3.4	Zone 6	Water	
NIPS.OAKDAPOAK	6	1.4	0	2.3	4.6	Zone 6	Water	
NIPS.ROSEWRWF	100.1	20.2	25.7	23.8	26.8	Zone 6	Wind	This is a tax equity joint venture w/ NIPSCO as controlling member
NIPS.INCROSWF	300.1	55.5	46.8	67.3	62.8	Zone 6	Wind	This is a tax equity joint venture w/ NIPSCO as controlling member
NIPS.SCHAHP16A	78	44.3	58.6	35.4	39.7	Zone 6	Gas	
NIPS.SCHAHP16B	77	63.4	70.6	77.1	68.4	Zone 6	Gas	
NIPS.DUNNBR1SF	265	181.7	109.2	3.2	154.3	Zone 6	Solar	This is a tax equity joint venture w/ NIPSCO as controlling member.
NIPS.INCRMLSP	200	131.4	85.7	1.6	108.2	Zone 6	Solar	This is a tax equity joint venture w/ NIPSCO as controlling member.
Dunns II	435	217.5	217.5	21.8	217.5	Zone 6	Solar	
Dunns II Battery	56.25	53.5	53.5	53.5	53.5	Zone 6	Battery	
Fairbank	250	125	125	12.5	125	Zone 6	Solar	
Gibson	200	100	100	10	100	Zone 6	Solar	
Calvary	200	109	77.5	7.8	77.5	Zone 6	Solar	
Calvary Battery	45	45	42.8	42.8	42.8	Zone 6	Battery	

Contracted Resource *IC 8-1-8.5-13(i)(2) definition*	**ICAP (MW)** *Nameplate capacity*	**Summer UCAP (MW)** *IC 8-1-8.5-13(f) definition*	**Fall UCAP (MW)** *IC 8-1-8.5-13(f) definition*	**Winter UCAP (MW)** *IC 8-1-8.5-13(g) definition*	**Spring UCAP (MW)** *IC 8-1-8.5-13(f) definition*	**Location:** *RTO interconnection zone*	**Fuel Source**	**Additional Comments**
[redacted]								
								Capacity from external resource zone
								Capacity from external resource zone
								Capacity from external resource zone

Demand Response Resource *IC 8-1-8.5-13(i)(3) definition*	**Summer UCAP (MW)** *IC 8-1-8.5-13(f) definition*	**Fall UCAP (MW)** *IC 8-1-8.5-13(g) definition*	**Winter UCAP (MW)** *IC 8-1-8.5-13(g) definition*	**Spring UCAP (MW)** *IC 8-1-8.5-13(g) definition*	**Additional Comments**
					Please see below, where NIPSCO has broken this out to account for Rate 831 Tier 2 and 3.

NIPSCO 531 Tier 2 & 3 Customers Contracted Resource	**Summer UCAP (ZRC)**	**Fall UCAP (ZRC)**	**Winter UCAP (ZRC)**	**Spring UCAP (ZRC)**	**Additional Comments**
A	0	0	0	0	Load Purchase Capacity (ZRC) by Customer
B	0	0	0	0	Load Purchase Capacity (ZRC)
C	169.9	121.6	176.5	199.1	Load Purchase Capacity (ZRC) by Customer
D	0	0	0	0	Load Purchase Capacity (ZRC) by Customer
E	0	0	0	0	Load Purchase Capacity (ZRC) by Customer
F	0	0	0	0	Load Purchase Capacity (ZRC) by Customer
G	0	0	0	0	Load Purchase Capacity (ZRC) by Customer

NIPSCO 531 Tier 2 & 3 Customers Load Modiying Resource	Summer Registered As LMR @ MISO (ZRC) (MW X (1+PRM) X (1+TL))	Fall Registered As LMR @ MISO (ZRC) (MW X (1+PRM) X (1+TL))	Winter Registered As LMR @ MISO (ZRC) (MW X (1+PRM) X (1+TL))	Spring Registered As LMR @ MISO (ZRC) (MW X (1+PRM) X (1+TL))	Additional Comments
A	198.9	176.3	164.0	209.0	Registered as LMR @ MISO by NIPSCO
B	0.0	0.0	0.0	0.0	Registered as LMR @ MISO by NIPSCO
C	0.0	0.0	0.0	0.0	Registered as LMR @ MISO by NIPSCO
D	79.7	84.0	86.8	89.1	Registered as LMR @ MISO by NIPSCO
E	0.0	0.0	0.0	0.0	Registered as LMR @ MISO by NIPSCO
F	152.0	170.6	186.4	189.5	Registered as LMR @ MISO by NIPSCO
G	185.9	198.9	186.2	229.8	Registered as LMR @ MISO by NIPSCO

		This minus Rate 531 Tier 2 & 3 Customers	This with Rate 531 Tier 2 & 3 Customers	Additional Comments
RTO established Planning Reserve Margin requirement *(see IC 8-1-8.5-13 (i)(4)*	Summer Demand ___ MWx(1+ % PRM ____) = ____MW	2600.8	3480.4	w/ TL of 2.5% PRMR of 7.9%

NIPSCO has peformed this calculation without Rate 531 Tier 2 and 3 customers (column D) and with those customers (column E)

Fall Demand ___ MWx(1+ % PRM ____) = ____MW	This minus Rate 531 Tier 2 & 3 Customers	This with Rate 531 Tier 2 & 3 Customers	Additional Comments
	2468.1	3409.1	w/ TL of 3.8% PRMR of 14.9%

Winter Demand ___ MWx(1+ % PRM ____) = ____MW	This minus Rate 531 Tier 2 & 3 Customers	This with Rate 531 Tier 2 & 3 Customers	Additional Comments
	1942	2897.6	w/ TL of 1.7% PRMR of 18.4%

Spring Demand ___ MWx(1+ % PRM ____) = ____MW	This minus Rate 531 Tier 2 & 3 Customers	This with Rate 531 Tier 2 & 3 Customers	Additional Comments
	2415.3	3472.1	w/ TL of 3.4% PRMR of 25.3%

Please describe any other federal reliability requirement:	

Reliability Adequacy Metrics *[defined in IC 8-1-8.5-13(e)]*			
Summer RA Metric *IC 8-1-8.5-13(e)(1)*	**Fall RA Metric** *IC 8-1-8.5-13(e)(2)*	**Winter RA Metric** *IC 8-1-8.5-13(e)(2)*	**Spring RA Metric** *IC 8-1-8.5-13(e)(2)*
Summer UCAP/PRM Requirement = _____%	Fall UCAP/PRM Requirement = _____%	Winter UCAP/PRM Requirement = _____%	Spring UCAP/PRM Requirement = _____%

NIPSCO has peformed this calculation (below) without Rate 531 Tier 2 and 3 customers (columns B and C) and with those customers (column D and E)

This minus Rate 531 Tier 2 & 3 Customers				This with Rate 531 Tier 2 & 3 Customers			
Summer UCAP	Fall UCAP	Winter UCAP	Spring UCAP	Summer UCAP	Fall UCAP	Winter UCAP	Spring UCAP
Summer RA Metric	Fall RA Metric	Winter RA Metric	Spring RA Metric	Summer RA Metric	Fall RA Metric	Winter RA Metric	Spring RA Metric

IC 8-1-8.5-13(i) Reporting Form - Planning Resource Year 3 (2027 to 2028)

Indiana Utility Regulatory Commission

Add rows below as necessary. For resources located outside of Zone 6, please provide a description of the deliverability arrangements.
For demand response resources, please provide a description of each program.

Owned Resource *IC 8-1-8.5-13(i)(1) definition*	**ICAP (MW)** *Nameplate capacity*	**Summer UCAP (MW)** *IC 8-1-8.5-13(f) definition*	**Fall UCAP (MW)** *IC 8-1-8.5-13(f) definition*	**Winter UCAP (MW)** *IC 8-1-8.5-13(g) definition*	**Spring UCAP (MW)** *IC 8-1-8.5-13(f) definition*	**Location:** *RTO interconnection zone*	**Fuel Source**	**Additional Comments**
CIN.SUCRKGT1	175	146.4	144.4	133.7	170.7	Zone 6	Gas	This is one combined asset.
CIN.SUCRKGT2	175	145.6	145.1	162.6	170.8	Zone 6	Gas	
CIN.SUCRKST1	228	202.4	192.1	181	223.1	Zone 6	Waste Heat	
NIPS.MICHCP12	469	313.4	311.5	170.9	317.6	Zone 6	Coal	
NIPS.NORWAPNOR	4	1.6	0.9	2.2	3.4	Zone 6	Water	
NIPS.OAKDAPOAK	6	1.4	0	2.3	4.6	Zone 6	Water	
NIPS.ROSEWRWF	100.1	20.2	25.7	23.8	26.8	Zone 6	Wind	This is a tax equity joint venture w/ NIPSCO as controlling member
NIPS.INCROSWF	300.1	55.5	46.8	67.3	62.8	Zone 6	Wind	This is a tax equity joint venture w/ NIPSCO as controlling member
NIPS.SCHAHP16A	78	44.3	58.6			Zone 6	Gas	Plan to retire end of 2027
NIPS.SCHAHP16B	77	63.4	70.6			Zone 6	Gas	Plan to retire end of 2027
NIPS.DUNNBR1SF	265	181.7	109.2	3.2	154.3	Zone 6	Solar	This is a tax equity joint venture w/ NIPSCO as controlling member.
NIPS.INCRMLSP	200	131.4	85.7	1.6	108.2	Zone 6	Solar	This is a tax equity joint venture w/ NIPSCO as controlling member.
Dunns II	435	217.5	217.5	21.8	217.5	Zone 6	Solar	
Dunns II Battery	56.25	53.5	53.5	53.5	53.5	Zone 6	Battery	
Fairbank	250	125	125	12.5	125	Zone 6	Solar	
Gibson	200	100	100	10	100	Zone 6	Solar	
Calvary	200	109	77.5	7.8	77.5	Zone 6	Solar	
Calvary Battery	45	45	42.8	42.8	42.8	Zone 6	Battery	
Templeton Wind	200	41.6	61.4	58	50.6	Zone 6	Wind	
Peaker	450			361.4	400.1	Zone 6	Gas	Approved Peaker

Contracted Resource *IC 8-1-8.5-13(i)(2) definition*	**ICAP (MW)** *Nameplate capacity*	**Summer UCAP (MW)** *IC 8-1-8.5-13(f) definition*	**Fall UCAP (MW)** *IC 8-1-8.5-13(f) definition*	**Winter UCAP (MW)** *IC 8-1-8.5-13(g) definition*	**Spring UCAP (MW)** *IC 8-1-8.5-13(f) definition*	**Location:** *RTO interconnection zone*	**Fuel Source**	**Additional Comments**
[redacted]								
								Capacity from external resource zone

Demand Response Resource *IC 8-1-8.5-13(i)(3) definition*	**Summer UCAP (MW)** *IC 8-1-8.5-13(f) definition*	**Fall UCAP (MW)** *IC 8-1-8.5-13(g) definition*	**Winter UCAP (MW)** *IC 8-1-8.5-13(g) definition*	**Spring UCAP (MW)** *IC 8-1-8.5-13(g) definition*	**Additional Comments**
					Please see below, where NIPSCO has broken this out to account for Rate 831 Tier 2 and 3.

NIPSCO 531 Tier 2 & 3 Customers Contracted Resource	**Summer UCAP (ZRC)**	**Fall UCAP (ZRC)**	**Winter UCAP (ZRC)**	**Spring UCAP (ZRC)**	**Additional Comments**
A	0	0	0	0	Load Purchase Capacity (ZRC) by Customer
B	0	0	0	0	Load Purchase Capacity (ZRC)
C	169.9	121.6	176.5	199.1	Load Purchase Capacity (ZRC) by Customer
D	0	0	0	0	Load Purchase Capacity (ZRC) by Customer
E	0	0	0	0	Load Purchase Capacity (ZRC) by Customer
F	0	0	0	0	Load Purchase Capacity (ZRC) by Customer
G	0	0	0	0	Load Purchase Capacity (ZRC) by Customer

NIPSCO 531 Tier 2 & 3 Customers Load Modiying Resource	Summer Registered As LMR @ MISO (ZRC) (MW X (1+PRM) X (1+TL))	Fall Registered As LMR @ MISO (ZRC) (MW X (1+PRM) X (1+TL))	Winter Registered As LMR @ MISO (ZRC) (MW X (1+PRM) X (1+TL))	Spring Registered As LMR @ MISO (ZRC) (MW X (1+PRM) X (1+TL))	Additional Comments
A	198.9	176.3	164.0	209.0	Registered as LMR @ MISO by NIPSCO
B	0.0	0.0	0.0	0.0	Registered as LMR @ MISO by NIPSCO
C	0.0	0.0	0.0	0.0	Registered as LMR @ MISO by NIPSCO
D	79.7	84.0	86.8	89.1	Registered as LMR @ MISO by NIPSCO
E	0.0	0.0	0.0	0.0	Registered as LMR @ MISO by NIPSCO
F	152.0	170.6	186.4	189.5	Registered as LMR @ MISO by NIPSCO
G	185.9	198.9	186.2	229.8	Registered as LMR @ MISO by NIPSCO

		This minus Rate 531 Tier 2 & 3 Customers	This with Rate 531 Tier 2 & 3 Customers	Additional Comments
RTO established Planning Reserve Margin requirement *(see IC 8-1-8.5-13 (i)(4)*	Summer Demand ___ MWx(1+ % PRM ____) = ____MW	2600.2	3479.8	w/ TL of 2.5% PRMR of 7.9%

NIPSCO has peformed this calculation without Rate 531 Tier 2 and 3 customers (column D) and with those customers (column E)

Fall Demand ___ MWx(1+ % PRM ____) = ____MW	This minus Rate 531 Tier 2 & 3 Customers	This with Rate 531 Tier 2 & 3 Customers	Additional Comments
	2467.4	3408.4	w/ TL of 3.8% PRMR of 14.9%

Winter Demand ___ MWx(1+ % PRM ____) = ____MW	This minus Rate 531 Tier 2 & 3 Customers	This with Rate 531 Tier 2 & 3 Customers	Additional Comments
	1942	2897.5	w/ TL of 1.7% PRMR of 18.4%

Spring Demand ___ MWx(1+ % PRM ____) = ____MW	This minus Rate 531 Tier 2 & 3 Customers	This with Rate 531 Tier 2 & 3 Customers	Additional Comments
	2414.8	3471.4	w/ TL of 3.4% PRMR of 25.3%

Please describe any other federal reliability requirement:	

Reliability Adequacy Metrics *[defined in IC 8-1-8.5-13(e)]*			
Summer RA Metric *IC 8-1-8.5-13(e)(1)*	**Fall RA Metric** *IC 8-1-8.5-13(e)(2)*	**Winter RA Metric** *IC 8-1-8.5-13(e)(2)*	**Spring RA Metric** *IC 8-1-8.5-13(e)(2)*
Summer UCAP/PRM Requirement = _____%	Fall UCAP/PRM Requirement = _____%	Winter UCAP/PRM Requirement = _____%	Spring UCAP/PRM Requirement = _____%

NIPSCO has peformed this calculation (below) without Rate 531 Tier 2 and 3 customers (columns B and C) and with those customers (column D and E)

This minus Rate 531 Tier 2 & 3 Customers				This with Rate 531 Tier 2 & 3 Customers			
Summer UCAP	Fall UCAP	Winter UCAP	Spring UCAP	Summer UCAP	Fall UCAP	Winter UCAP	Spring UCAP
[redacted]							
Summer RA Metric	Fall RA Metric	Winter RA Metric	Spring RA Metric	Summer RA Metric	Fall RA Metric	Winter RA Metric	Spring RA Metric
[redacted]							

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. 202-26-46
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	)))))	Order No. 202-26-47

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

Exhibit 13
NIPSCO Performance Metric
Collaborative Update

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY FOR AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE AND FOR APPROVAL OF: (1) CHANGES TO ITS ELECTRIC SERVICE TARIFF INCLUDING A NEW SCHEDULE OF RATES AND CHARGES AND CHANGES TO THE GENERAL RULES AND REGULATIONS AND CERTAIN RIDERS; (2) REVISED DEPRECIATION ACCRUAL RATES; (3) INCLUSION IN ITS BASIC RATES AND CHARGES OF THE COSTS ASSOCIATED WITH CERTAIN PREVIOUSLY APPROVED QUALIFIED POLLUTION CONTROL PROPERTY, CLEAN COAL TECHNOLOGY, CLEAN ENERGY PROJECTS AND FEDERALLY MANDATED COMPLIANCE PROJECTS; AND (4) ACCOUNTING RELIEF TO ALLOW NIPSCO TO DEFER, AS A REGULATORY ASSET OR LIABILITY, CERTAIN COSTS FOR RECOVERY IN A FUTURE PROCEEDING.	)	**CAUSE NO. 44688**

COMPLIANCE FILING
PERFORMANCE METRIC COLLABORATIVE UPDATE

Ordering Paragraph 10 of the Indiana Utility Regulatory Commission's July 18, 2016 Order issued in this Cause ("Rate Case Order") directed Northern Indiana Public Service Company LLC ("NIPSCO") to participate in a collaborative for the purpose of implementing performance metrics. The Commission ordered that

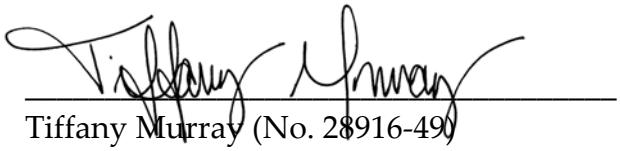
NIPSCO shall keep the Commission apprised of the progress of the collaborative through compliance filings made under this Cause as described in its Order as follows:

> [W]e find that NIPSCO shall facilitate a meeting with interested stakeholders within six weeks of the effective date of the Order in this Cause to collaborate on a path for moving forward with a performance metrics initiative.
>
> * * *
>
> In order that the Commission and interested stakeholders may stay abreast of the collaborative process, we direct NIPSCO to make a progress update filing with the Commission within 90 days of the initial meeting of the collaborative. We also order NIPSCO to file quarterly reports for the first year and an annual report by July 1, 2017, and for each year thereafter until otherwise indicated by the Presiding Officers.

Attached please find NIPSCO's Performance Metric Collaborative Report dated July 1, 2025, which incorporates revisions and language as provided by the interested stakeholders participating in NIPSCO's Performance Metrics Collaborative.

NIPSCO will file an annual Performance Metrics Collaborative Report for each year hereafter until otherwise indicated by the Presiding Officers.

Respectfully submitted:



Tiffany Murray (No. 28916-49)
NiSource Corporate Services - Legal
150 West Market Street, Suite 600
Indianapolis, Indiana 46204
Phone: (317) 649-6424
Fax: (317) 684-4918
Email: tiffanymurray@nisource.com

Attorney for Petitioner
Northern Indiana Public Service Company LLC

CERTIFICATE OF SERVICE

The undersigned hereby certifies that the foregoing was served by email transmission upon the following:

OUCC
William Fine
Carol Sparks Drake
Office of Utility Consumer Counselor
115 W. Washington Street
Suite 1500 South
Indianapolis, Indiana 46204
wfine@oucc.in.gov
cadrake@oucc.in.gov
infomgt@oucc.in.gov

NIPSCO INDUSTRIAL GROUP
Todd A. Richardson
Tabitha L. Balzer
Lewis & Kappes, P.C.
One American Square, Suite 2500
Indianapolis, Indiana 46282
trichardson@lewis-kappes.com
tbalzer@lewis-kappes.com

U.S. STEEL
Nikki G. Shoultz
Bose McKinney & Evans LLP
111 Monument Circle, Suite 2700
Indianapolis, Indiana 46204
nshoultz@boselaw.com

CITIZENS ACTION COALITION
Jennifer A. Washburn
Citizens Action Coalition
603 East Washington Street, Suite 502
Indianapolis, Indiana 46204
jwashburn@citact.org
rkurtz@citact.org

INDIANA MUNICIPAL UTILITY GROUP
Robert M. Glennon
Robert Glennon & Assoc., P.C.
3697 N. Co. Rd. 500 E
Danville, Indiana 46122
glennon@iquest.net

UNITED STEELWORKERS
Antonia Domingo
United Steelworkers
60 Boulevard of the Allies, 8th Floor
Pittsburgh, Pennsylvania 15208
adomingo@usw.org

NLMK INDIANA
Anne E. Becker
Lewis & Kappes, P.C.
One American Square, Suite 2500
Indianapolis, Indiana 46282
abecker@lewis-kappes.com

James W. Brew
Stone Mattheis Xenopoulos & Brew, PC
1025 Thomas Jefferson St., N.W.
8th Floor, West Tower
Washington, DC 20007
jbrew@smxblaw.com

WALMART
Eric E. Kinder
Spilman Thomas & Battle, PLLC
300 Kanawha Boulevard, East
P.O. Box 273
Charleston, West Virginia 25321
ekinder@spilmanlaw.com

Barry A. Naum
Spilman Thomas & Battle, PLLC
1100 Bent Creek Boulevard, Suite 101
Mechanicsburg, Pennsylvania 17050
bnaum@spilmanlaw.com

Carrie M. Harris
Spilman Thomas & Battle, PLLC
310 First Street, Suite 1100
P.O. Box 90
Roanoke, Virginia 24002-0090
charris@spilmanlaw.com

LAPORTE COUNTY
Shaw R. Friedman
Friedman & Associates, P.C.
705 Lincolnway
LaPorte, Indiana 46350
Sfriedman.associates@frontier.com

Keith L. Beall
Beall & Beall
13238 Snow Owl Dr., Ste. A
Carmel, Indiana 46033
kbeall@clarkquinnlaw.com

PRAXAIR
Timothy L. Stewart
Lewis & Kappes, P.C.
One American Square, Suite 2500
Indianapolis, Indiana 46282-0003
tstewart@lewis-kappes.com

ELPC
Jennifer A. Washburn
Citizens Action Coalition
603 East Washington Street, Suite 502
Indianapolis, Indiana 46204
jwashburn@citact.org

Bradley Klein
Environmental Law & Policy Center
35 E Wacker Drive, Suite 1600
Chicago, Illinois 60601
bklein@elpc.org

Robert Kelter
Environmental Law & Policy Center
35 E Wacker Drive, Suite 1600
Chicago, Illinois 60601
rkelter@elpc.org

Dated this 1st day of July, 2025.



Tiffany Murray

July 1, 2025

Via Electronic Filing
Honorable James F. Huston
Chair
Indiana Utility Regulatory Commission
101 West Washington Street, Suite 1500 East
Indianapolis, Indiana 46204

RE: Cause No. 44688; Compliance Filing – Performance Metric Report

Dear Chair Huston:

Enclosed please find the Performance Metric Report prepared by Northern Indiana Public Service Company LLC ("NIPSCO") reporting 2024 results. As in previous years, NIPSCO provided the stakeholders involved in Cause No. 44688 with the opportunity to review and comment on the document, but the information was compiled by NIPSCO. Pages 3 through 5 of the report provide an overview of the 2024 results and the appendix includes the data utilized in developing the graphs.

NIPSCO appreciates the participation of the stakeholders, particularly during the June 10, 2025 meeting to review the 2024 results. Please contact me if you have any questions or concerns.

Sincerely,

Erin E. Whitehead
Vice President, Regulatory and Major Accounts

Encl.
cc: (w/ encl. – via email transmission) to Service List in Cause No. 44688

Northern Indiana Public Service Company LLC

2024 PERFORMANCE METRIC REPORT

Filed July 1, 2025









OUR VISION IS TO BE A
PREMIER, INNOVATIVE & TRUSTED
ENERGY PARTNER



NIPSCO
A NiSource Company

TABLE OF CONTENTS

EXECUTIVE SUMMARY ____ 3
- Background ____ 3
- Safety ____ 3
- Reliability ____ 3
- Customer Service ____ 4
- Investment and Spending ____ 4
- Affordability ____ 5
- Staffing ____ 5

SAFETY ____ 6
- Vehicle Safety ____ 6
- Field Safety ____ 7
- Electric Underground Damages ____ 10

RELIABILITY ____ 11
- Power Delivery ____ 11
- Power Generation ____ 16
- Renewable Generation ____ 23

DISTRIBUTED GENERATION ____ 28
- Small Power Production ____ 29

CUSTOMER SERVICE ____ 30
- Customer Satisfaction ____ 32

INVESTMENT AND SPENDING ____ 36
- Total O&M ____ 36
- O&M Components ____ 37
- Benchmarking Analysis ____ 41

AFFORDABILITY ____ 43
- Customer Bills ____ 43
- Service Disconnections ____ 46

STAFFING ____ 48
CONCLUSION ____ 50
APPENDIX ____ 51

EXECUTIVE SUMMARY

Background

This document is the ninth performance metric report Northern Indiana Public Service Company LLC ("NIPSCO" or "Company") has submitted to the Indiana Utility Regulatory Commission ("Commission" or "IURC") in compliance with the Commission's July 18, 2016, Order in Cause No. 44688 (the "44688 Order"). The purpose of this report is to communicate NIPSCO's performance in areas such as safety, reliability, customer service, and operations in 2024. This report includes the same data sets used in prior reports and expounds on these metrics to enable interested stakeholders, the Commission, and NIPSCO, to understand and utilize key metrics. NIPSCO strives to deliver customer value in a balanced manner across four key dimensions – safety, customer experience, reliability, and affordability.

Safety

NIPSCO continues to promote a Stop Work Authority policy, which empowers employees to stop work whenever they see an employee, business partner, or member of the public who is at risk of harm. NIPSCO also continues its partnership with Vimocity, promoting NIPSCO Moves, which is a company led initiative aimed at preventing ergonomic strain and sprain injuries. In 2024, NIPSCO Moves was extended to all office employees and is now available to all NIPSCO employees and their families.

In terms of driving safety, NIPSCO successfully upgraded from the GreenRoads telematics program and partnered with Samsara. The new technology uses dual inward and outward facing cameras to detect unsafe driving behaviors and provides the driver with real time feedback for correction. Installs were completed for the entire NIPSCO fleet in 2024. Since installation, we have seen a significant reduction in driving events.

Reliability

Power Delivery: NIPSCO continues to work on its core reliability improvement programs, such as vegetation management and grid modernization, and is focused on improving its reliability metrics.

Power Generation: NIPSCO added a solar facility and a battery energy storage system (Cavalry Solar Field / Cavalry Battery Energy Storage System) in 2024, with both beginning operation in May 2024, expanding NIPSCO's renewable energy generation portfolio.

NIPSCO's coal EFOR has been significantly affected by changing power markets, which has impacted the economical dispatch for coal. NIPSCO's coal EFOR increased slightly in 2024 due to units not being dispatched as often and an increase in planned and maintenance outage hours in 2024. The EFOR at NIPSCO's Sugar Creek unit ticked up slightly from 2023 due to tube and steam leaks on the heat recovery steam generator.

Customer Service

In 2024, NIPSCO customer satisfaction increased over 2023 with the customer service representatives, the IVR (automated phone system), and the online self-service web experiences. First call resolution increased from 83% in 2023 to 89% in 2024 and average speed to answer continued to improve in 2024.

NIPSCO's 2024 J.D. Power Residential Customer satisfaction survey for the Midwest region of midsize utilities scores NIPSCO at 700, which is above the group average of 692 and the highest of the three Indiana electric investor-owned utilities in the segment. In J.D. Power's Business Customer satisfaction survey, NIPSCO received a score of 804, which is above the group average of 779, and the highest out of Indiana's three electric investor-owned utilities in the segment.

In 2024, 49 IURC complaints were filed by customers, and only two were substantiated. This reflects a slight uptick from the number of complaints filed in 2023 but is still significantly less than the number of complaints filed during the period of 2011 through 2019. The number of complaints trended downward during the pandemic years of 2020 and 2021.

Investment and Spending

NIPSCO continued to reduce operational O&M costs in many areas in 2024. Fuel and purchased power costs further decreased by $72 million, while total O&M costs decreased by $92 million, meaning that non-fuel O&M decreased by approximately $20 million in 2024

compared to 2023[1]. Total O&M costs, normalized on a per megawatt hour ("MWh") and per retail customer basis, also decreased for NIPSCO in 2024, driven by lower fuel and purchased power costs, non-fuel production expenses, and certain A&G expenses. NIPSCO's normalized non-fuel O&M costs slightly increased in 2023 compared to 2022 but reduced back to 2022 levels in 2024. Overall, non-fuel O&M has remained at a consistent level in the last 10 years, indicating that cost containment efforts at both NiSource and NIPSCO have continued to be effective.

Affordability

NIPSCO is committed to providing safe, reliable, resilient, stable, environmentally sustainable and affordable service to its customers. In 2024, residential, commercial, and industrial customers all experienced an increase in their average monthly bill due to a base rate case implemented March 1, 2024. NIPSCO's investment in renewable generation resources, which is expected to yield long-term cost savings for customers, requires upfront capital that results in near-term rate increases. NIPSCO residential customers also have the lowest average monthly usage of the Indiana investor-owned utilities, which can contribute to an overall lower average bill. NIPSCO continues to proactively communicate with customers via text, email, and phone calls, and work with customers to make payments manageable. NIPSCO has various payment plans that range from three months up to 12 months, and the Company encourages customers to sign up for budget billing to keep payments consistent throughout the year and promotes energy efficiency programs to help customers reduce usage. NIPSCO has also recently proposed a new bill assistance program for low income customers to assist with summer electric bills, deposits, and late payment fees, which is pending Commission approval.

Staffing

NIPSCO has realized a substantial decrease in employee turnover after seeing the metric peak in 2021. This decrease was mainly due to a significant decline in retirements. In 2024, there was a slight increase in turnover due to retirements and discharges. In 2024, NIPSCO also saw its percentage of both female and non-white employees increase, continuing a positive trend dating back to 2015.

[1] Fuel and purchased power costs had decreased by $138 million in 2023 (compared to 2022), while total O&M costs had decreased by $114 million. The non-fuel O&M had increased by approximately $24 million in 2023 compared to 2022.

SAFETY

Safety is a core value of the NIPSCO organization. The Company's safety policies reflect a "just culture" mindset, which is a model used by high consequence industries to improve the way they approach system safety and staff accountability.

Organizations foster a just culture by looking first at systematic issues rather than individual performance. This approach recognizes that all employees make errors, and therefore a company should design its systems and procedures so that when an error occurs, injuries are limited, due to multiple layers of protection. This is the "Fail Safely" approach incorporated by the Company.

NIPSCO employees have increasingly embraced safety initiatives over the past few years. Metrics used by the Company to measure its safety efforts are discussed below.

Vehicle Safety

As part of a continuous improvement initiative, NIPSCO installed Samsara telematics throughout our fleet in 2024. The new technology uses dual inward and outward facing cameras to detect unsafe driving behaviors and provides the driver with real time feedback for correction. The system can detect speeding, unsafe following distances, mobile device usage, rolling stops, inattentive driving, policy violations such as not using a seatbelt or mobile device usage, and harsh events, such as aggressive braking, turning, and acceleration. This system allows supervisors the opportunity to coach their employees' driving behaviors.

Installation of Samsara was completed in October 2024. In a comparison of the fourth quarter of 2024 to the first quarter of 2025, NIPSO has seen a 73% decrease in mobile usage and a 62% decrease in no seat belt usage.

Figure 1. **Preventable Vehicle Crash Rate**

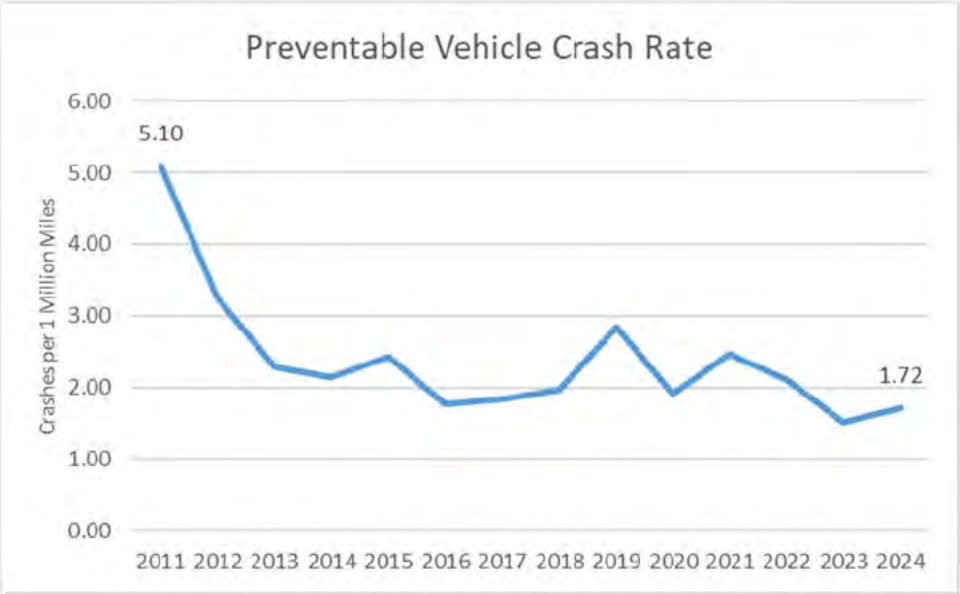


Figure 1 illustrates NIPSCO's preventable vehicle crash rate, which represents the number of crashes per one million miles driven, in which any employee, while driving on Company business, failed to do everything reasonably possible to avoid a collision. This metric is combined for gas and electric. The preventable vehicle crash rate remains relatively flat with only a slight uptick from 1.5 to 1.7 in 2024. Vehicle collisions with stationary objects continue to be a primary driver in our preventable vehicle crash rates. While previously minor contacts might have gone unreported, now the newly installed Samsara system will often register these events. This results in more events being documented and classified as preventable vehicle collisions, driving the overall vehicle incident rate up for the year. However, this improved reporting provides visibility into areas of focus for NIPSCO to continue efforts toward decreasing the vehicle crash rate going forward.

Field Safety

NIPSCO strives to make safety a foremost priority for its employees every day. Supervisors are encouraged to begin each meeting with a safety moment in an effort to ensure safe working practices become ingrained in the Company's culture. Field employees receive Human and Organizational Performance ("HOP") training, which includes emphasis on human error reduction tools, such as pre-job briefing and Stop Work Authority. The Company is committed to ensuring its employees have a deeper understanding of human error and how to prevent it. HOP places an emphasis on organizational weaknesses as well as understanding personal capabilities, assessing levels of risk, and controlling that risk through use of layers of protection and error prevention techniques. Employees conduct a pre-job

briefing before each work task, which includes the identification of unique site hazards, special precautions, required personal protective equipment, energy control, and critical work procedures. Local management then reviews these briefings to follow up on any potential operating issues. NIPSCO continues to promote a Stop Work Authority policy, which empowers employees to stop work whenever they see an employee, business partner, or member of the public who is at risk of harm.

The OSHA recordable incident rate, in Figure 2, represents the number of recordable injury or illness cases for every 100 full-time generation and power delivery employees. Most injuries or illnesses that require more than first aid treatment are recordable.

The days away, restricted, or transferred (DART) metric, in Figure 2, represents the number of injury or illness cases requiring days away, restricted duty, or job transfer for every 100 generation and power delivery full-time employees. This number indicates the rate of injuries that result in an employee being unable to perform their typical job requirements.

Figure 2. Employee Injuries – Generation and Power Delivery Divisions

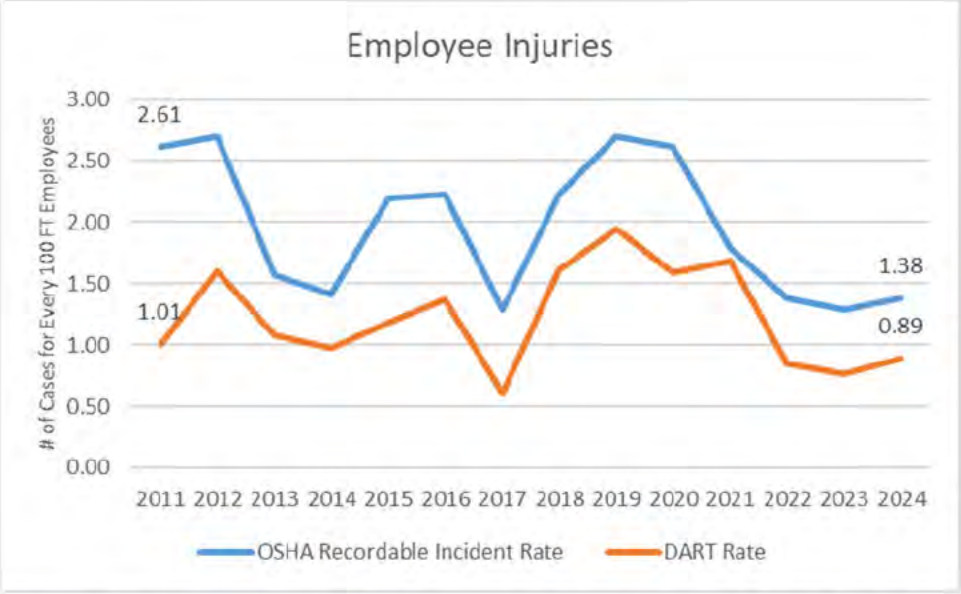


Figure 2 illustrates the two metrics NIPSCO uses to measure employee safety in the field for electric employees in the generation and power delivery divisions. NIPSCO continues to focus on improving these metrics.

Figure 3. **Employee Injuries – NIPSCO with Business Service Allocation ("BSA")**

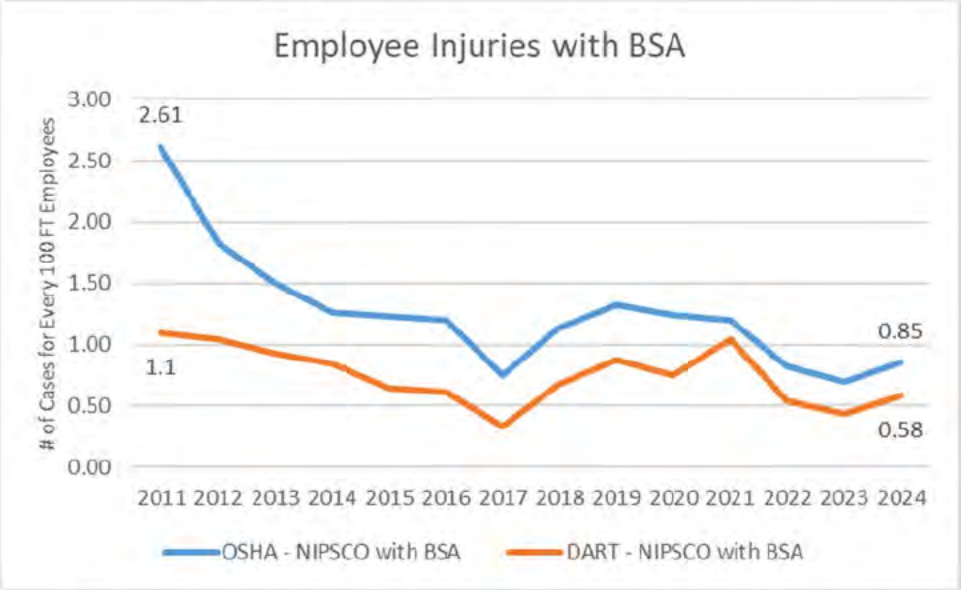


Figure 3 illustrates the two metrics NIPSCO uses to measure employee safety in the field for all NIPSCO employees. In comparison to 2023, NIPSCO's OSHA recordable rate and DART rate for 2024 slightly increased, but NIPSCO remains focused on continued safety improvements.

During 2024 NIPSCO rolled out an injury prevention program through a partnership with a third-party telemedicine provider that emphasizes proactive care for more minor injuries as a response to our ongoing challenges with strain and sprain style events. This has resulted in increased treatment of minor events that might previously have gone unreported, leading to a slight increase in injuries in 2024.

NIPSCO benchmarks this metric against AGA data for combination gas and electric utilities. In 2024, NIPSCO was in the second quartile in this category.

NIPSCO's safety culture has made progress over the years. NIPSCO continues work on its SMS, with integration and expansion of the program into its electric operations. The SMS program is based on American Petroleum Institute Recommended Practice 1173. SMS is anchored by NIPSCO's Core Four Responsibilities, which include: (1) Following Our Processes and Procedures; (2) Identifying and Reporting Risks; (3) Continually Improving Processes and Procedures; and (4) Identifying and Proactively Taking Action.

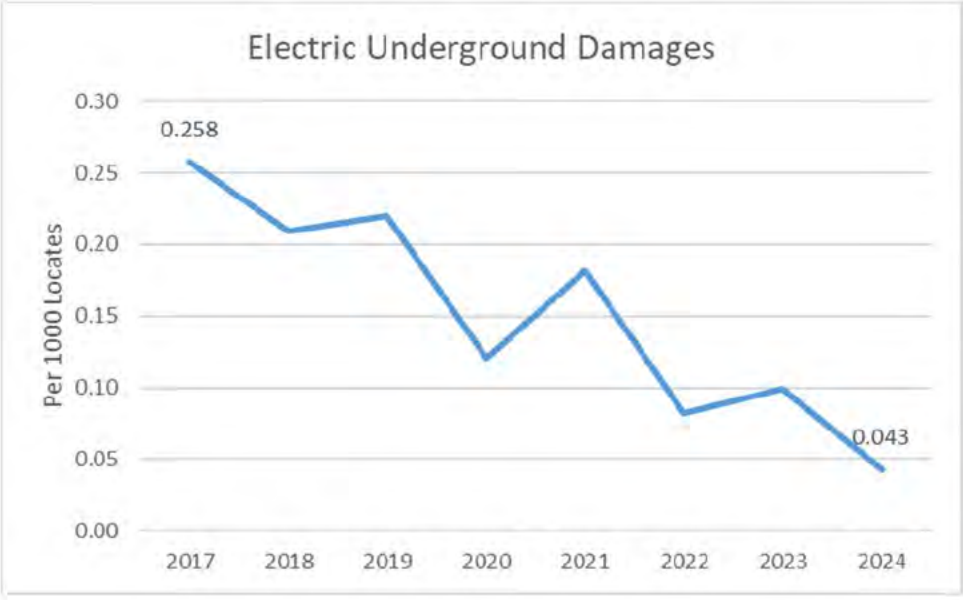
NIPSCO's SMS journey is taking safety to a new level of continuous improvement. It brings together people, processes, and culture to proactively find and act on risks to employees, contractors, customers, and communities. The Corrective Action Program ("CAP") is a foundational part of that effort. The CAP offers a simple way to document identified risks and a systematic process to review, prioritize, address, and track progress to reduce risks. Submitting an issue, concern, or risk in the CAP starts a rigorous process that can lead to resolving a prioritized risk through corrective action.

Maintaining our focus on combatting ergonomic hazards, NIPSCO has continued our partnership with Vimocity through the NIPSCO Moves program. This includes development of targeted resources, such as video material demonstrating improved body positioning during high-risk tasks, and lessons learned documents to identify opportunities for improvement when ergonomic injuries occur.

Electric Underground Damages

Figure 4 illustrates the *electric underground damages* metric. This metric represents the number of reported electric damages, divided by the number of electric locate tickets received through the 811 process, multiplied by 1,000. This metric has been steadily improving dating back to 2017 due to increased communication and awareness to call 811 before you dig. In 2024, there were 12 reported electric damages out of 279,070 locate tickets received by NIPSCO through the 811 process.

Figure 4. Electric Underground Damages per 1000 Locates



RELIABILITY

Power Delivery

Utilities use three principal indices to measure service reliability.

1. System Average Interruption Duration Index ("SAIDI"): represents the average outage duration of each electric customer served. A customer must lose service for five minutes or more for the incident to be defined as an interruption.

$$SAIDI = \frac{\sum electric\ customer\ outage\ minutes}{electric\ customers}$$

2. System Average Interruption Frequency Index ("SAIFI"): represents how many times per year the average customer experiences an interruption in electric supply. A customer must lose service for five minutes or more for the incident to be defined as an interruption.

$$SAIFI = \frac{\Sigma\ electric\ customer\ interruptions}{electric\ customers}$$

3. Customer Average Interruption Duration Index ("CAIDI"): represents the average length of outage for customers who experience an outage. CAIDI is therefore equal to SAIDI divided by SAIFI. A customer must lose service for five minutes or more for the incident to be defined as an interruption.

$$CAIDI = \frac{\sum electric\ customer\ outage\ minutes}{electric\ customer\ interruptions}$$

A major event day ("MED") is a day on which a weather or operational event causes a utility's daily SAIDI to exceed a calculated threshold ("TMED").[2] A single event may cause multiple MEDs and power outages may continue for days after the event is over.

[2] The TMED calculation is based on IEEE Standard 1366-2012 and uses a utility's daily SAIDI values for the past five reporting years.

Figure 5A. Major Event Day Metrics

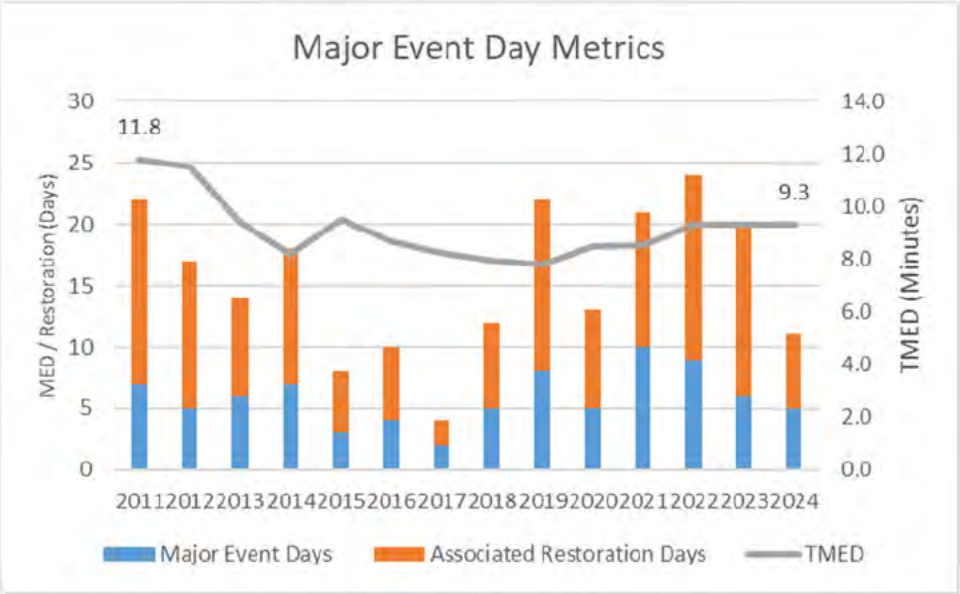


Figure 5A illustrates the number of MEDs in NIPSCO's service territory, the number of restoration days associated with those MEDs, and the TMED used to identify major event days each year. The five MEDs and six associated restoration days in 2024 represent a decrease from 2023 figures.

In an effort to improve reliability for power delivery, NIPSCO has steadily increased funding for its vegetation management program, specifically focusing on trimming more circuit miles on distribution and sub-transmission circuits. Much of the increase in funding is directed toward circuits with the highest tree-related outages and/or highest customer impacts. This plan has resulted in a decreasing trend in tree-related outages over the years, but with a slight increase in 2024, as shown in Figure 5B.

The future of NIPSCO's vegetation management program also recognizes the changing climate conditions and the challenges that come with maintaining vegetation sustainably, while continuing to drive down tree-related outages. During 2024, NIPSCO's vegetation management team began to use advanced data analytics to assist in the development of future year work plans. This data was used in 2024 to ensure the focus of the program combines tree related outages, vegetation imagery, and efficient cost control. NIPSCO trimmed 954 miles in 2023 and 1,157 miles in 2024.

Figure 5B. Number of Tree-Related Outages

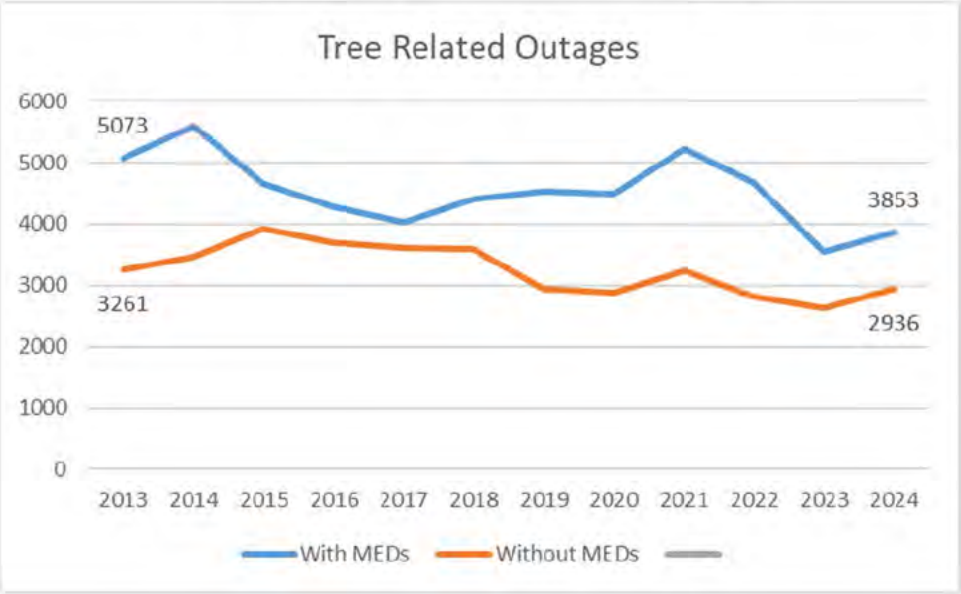


Figure 6. Reliability Indices (including MED)

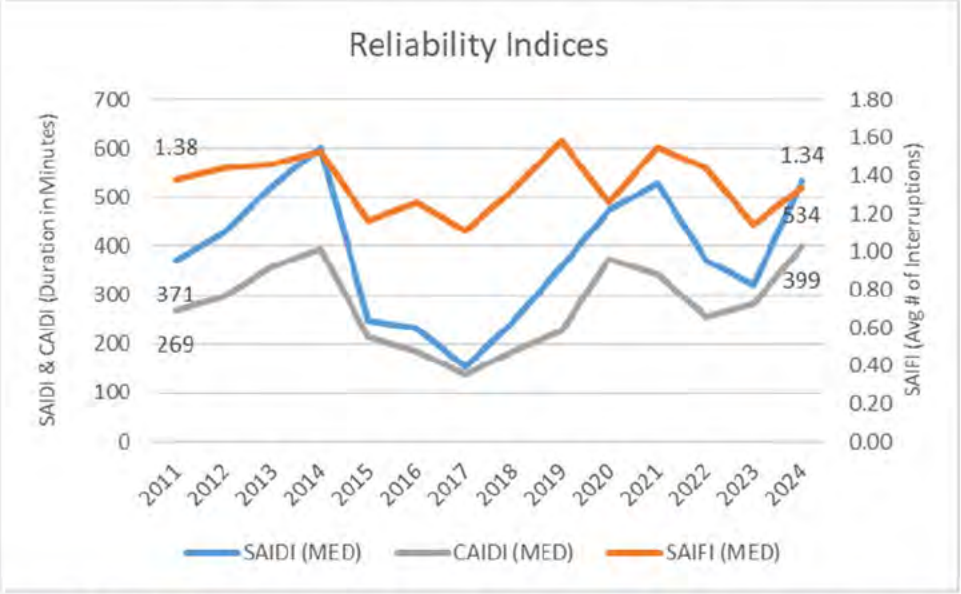


Figure 6 illustrates NIPSCO's three reliability indices, using MED data. MEDs are primarily storms or severe weather events that are more destructive than typical storm events.

For the 12-month period ending December 31, 2024, there were five storm events in NIPSCO's electric service territory that met the minimum criteria for a "major event trigger" and encompassed six days. In addition, there were nineteen weather events that NIPSCO would consider as severe (> 20% of TMED in a 24-hour period).

Figure 7. **Reliability Indices (excluding MED data)**

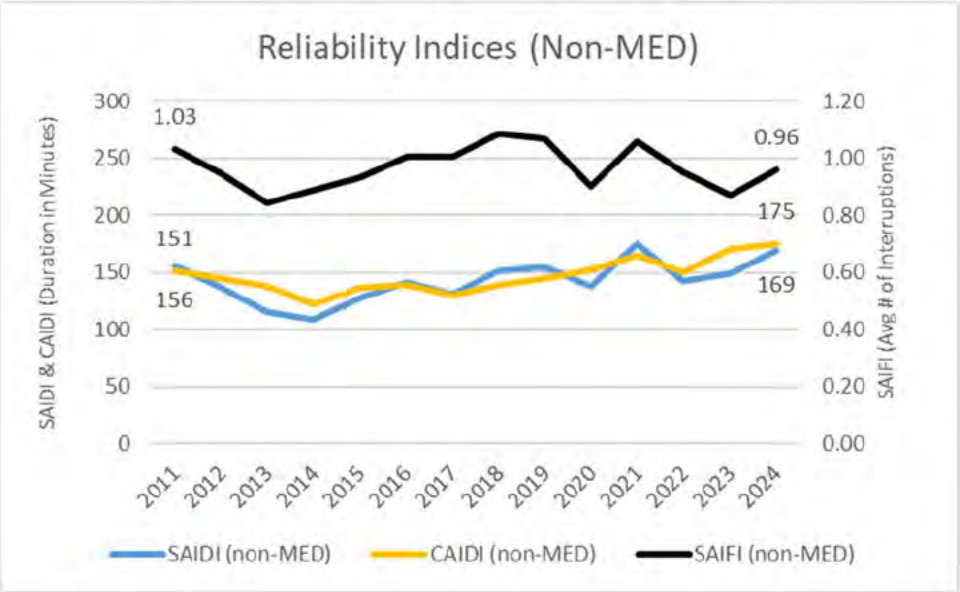


Figure 7 illustrates NIPSCO's three reliability indices, excluding MED data, which is identified using TMED. If a utility's daily SAIDI exceeds the TMED, the outage data on that date is excluded from the utility's non-MED reliability indices.

For SAIDI, in 2024, NIPSCO saw a slight increase of twenty minutes compared to 2023. NIPSCO's SAIDI has generally been slightly above the IEEE industry median for medium-sized utilities since 2015. IEE industry data for 2024 will not be available until after this report is submitted.

For SAIFI, in 2024, the average NIPSCO electric customer experienced a power interruption 0.96 times. This represents an increase from the 2023 figure of 0.87. NIPSCO's SAIFI has generally been below (better than) or just slightly above the IEEE industry median for medium-sized utilities.

For CAIDI, in 2024, NIPSCO saw an increase of four minutes compared to 2023. NIPSCO's CAIDI has been above the IEE industry median for medium-sized utilities since 2011.

NIPSCO continues to invest in its electric system to improve reliability, through its grid modernization program under its transmission, distribution, storage system improvement charge (TDSIC) plan, approved by the Commission in Cause No. 45557. TDSIC and other capital investments have had a positive impact on NIPSCO reliability and resiliency. NIPSCO's grid modernization program focused on increasing visibility and control for

NIPSCO T&D system for better planning, decreased outage frequency, and decreased response times for outages. Through communication expansion, substation and distribution automation, over 39,000 customer interruptions were avoided in 2024, We estimate a savings of approximately 30% of customer interruptions by 2034, which will positively impact our SAIFI metric.

NIPSCO is also focused on aging infrastructure to address assets in poor condition and/or at end of life. This includes planned replacements, removing unplanned, long duration outages, such as substation transformer failures or underground cable failures. Over 90% of NIPSCO's underground faults are associated with its unjacketed cable population; hundreds of miles have been replaced, removing potential future outages. 85% less customer interruptions on circuits were addressed through this program. Wood and steel life extension programs have strengthened the existing support structures fleet while removing those at their end of life under planned conditions.

NIPSCO's TDSIC efforts also address deliverability and capacity by focusing on upgrading the system to accommodate load growth, while providing capacity to back up other loads during an outage event. Substation equipment and circuit conductors have been upgraded to meet load demand before asset fail due to overloads. New circuit tie points to provide alternative sources in the event of an outage have been created, allowing customers to be restored faster.

NIPSCO is also upgrading its distribution automation system to isolate and restore customers, which is intended to reduce outage severity and duration, improving the customer experience. In addition, NIPSCO investigates all outages affecting more than 1,000 customers and utilizes lessons learned to improve construction standards, material selection, system configuration, and operating procedures.

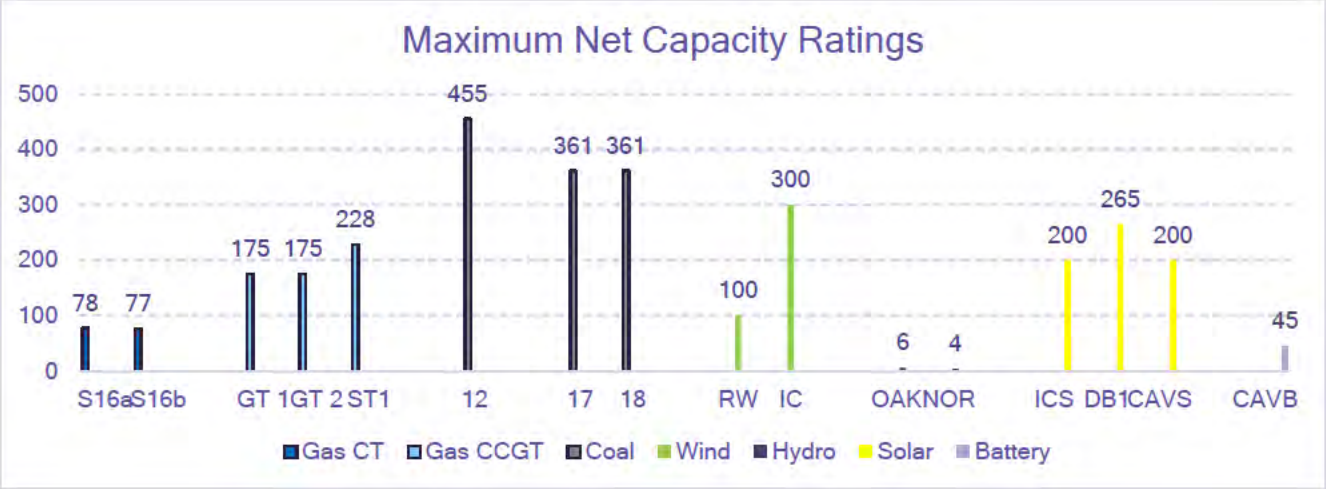
NIPSCO has a large amount of rural service territory, which affects deployment of service teams, and is located near Lake Michigan, which has effects on weather patterns, and such weather compounds the effects of the rural service territory. Also, NIPSCO is still in the process of fully deploying advanced metering infrastructure ("AMI"), whereas other utilities in Indiana have completed or are near completion.

Reliability indices are impacted due in part to the need in many cases for NIPSCO to tie circuits to adjacent substations or circuits during construction activities, which when an outage occurs on circuits that are tied, it results in an increased number of impacted customers. NIPSCO anticipates that improvements in its current TDSIC plan, which includes grid modernization investments and the full deployment of technologies like AMI, will improve NIPSCO's response and outage restoration times through faster outage reporting, allowing crews to be dispatched quicker. These technologies will also help NIPSCO locate damaged assets by reducing the patrol time that is currently required. This aligns with NIPSCO's focus to improve these metrics for the benefit of customers and to positively impact reliability.

Power Generation

NIPSCO's generating facilities have a total installed capacity of 3,030 net megawatts ("MW") and consist of ten separate generation sites, including Schahfer Generating Station (Units 16A, 16B, 17 and 18), Michigan City Generating Station (Unit 12), Sugar Creek Generating Station (SC1, SC2, and SS1), Rosewater Wind Farm , Indiana Crossroads I Wind Farm , Dunns Bridge Solar Farm, Indiana Crossroads Solar Farm, Cavalry Solar Field / Cavalry Battery Energy Storage System[3], and two (2) hydroelectric generating sites (Oakdale and Norway). The power generation metrics present NIPSCO's generation productivity by large generator type: coal, gas combustion turbine, combined cycle natural gas, hydroelectric, solar, wind, and battery storage.

Figure 8A. Installed Net Capacity of Generating Units (MW)



[3] Cavalry Solar (CAVS) and Cavalry Battery Energy Storage System (CAVB) interconnection output limited to 200 MW.

Figure 8A illustrates NIPSCO's current generation portfolio, in MW.

Effective with Planning Year 2023-2024, MISO began awarding thermal resource accreditation seasonally, based on each resource's availability during all hours, and hours with the tightest operating conditions, to reflect the actual availability of resources when they are most needed.

Figure 8B.[4]

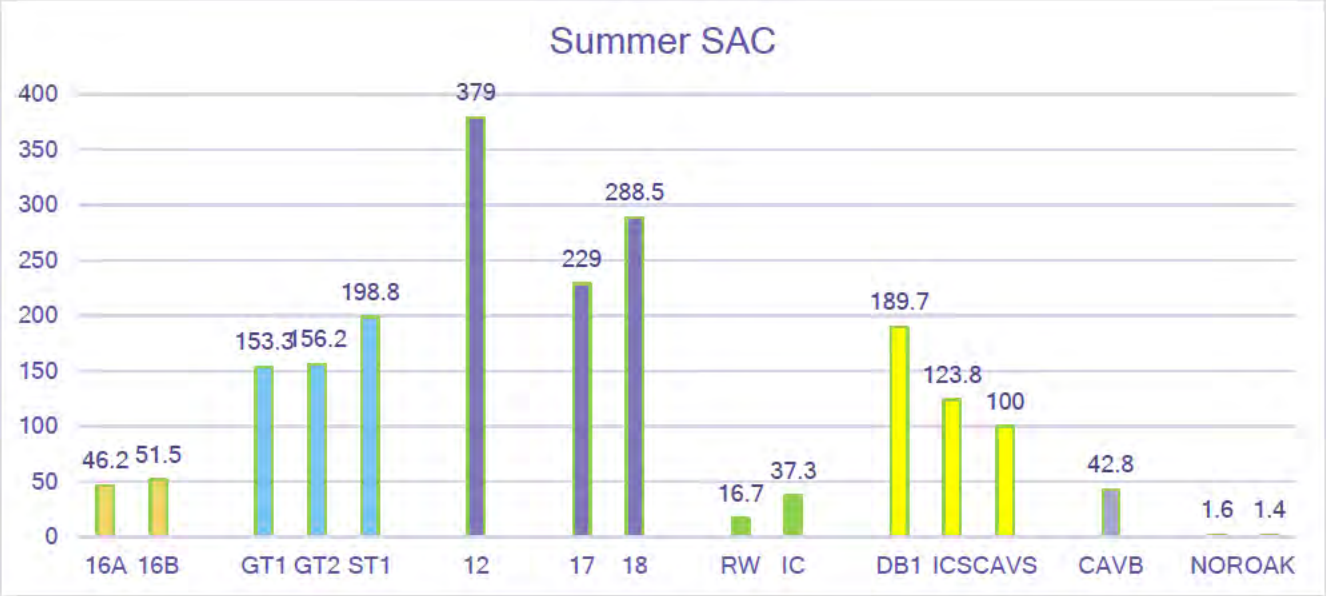


Figure 8B shows the summer Seasonal Accredited Capacity (SAC) for NIPSCO generating units.

Figure 8C illustrates the SAC for NIPSCO's generating units for the fall season.

[4] Dunns Bridge 1 Commercial Operation Date was later than the start of the summer season.

Figure 8C.

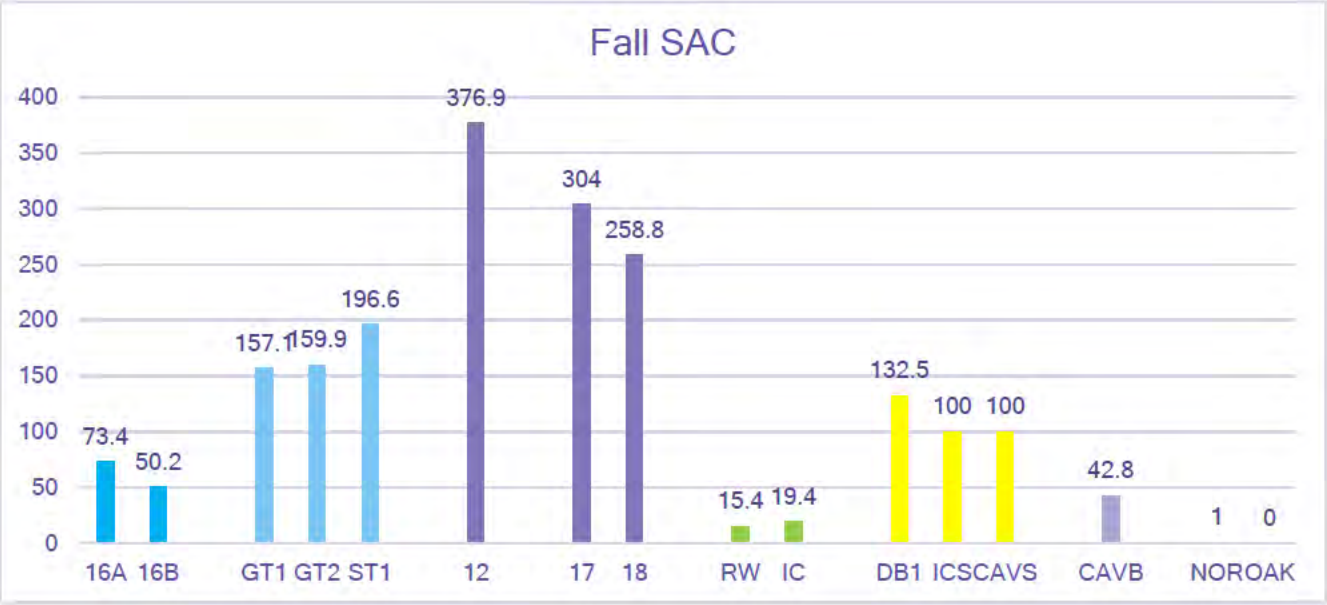


Figure 8D illustrates the SAC for NIPSCO's generating units for the winter season.

Figure 8D.

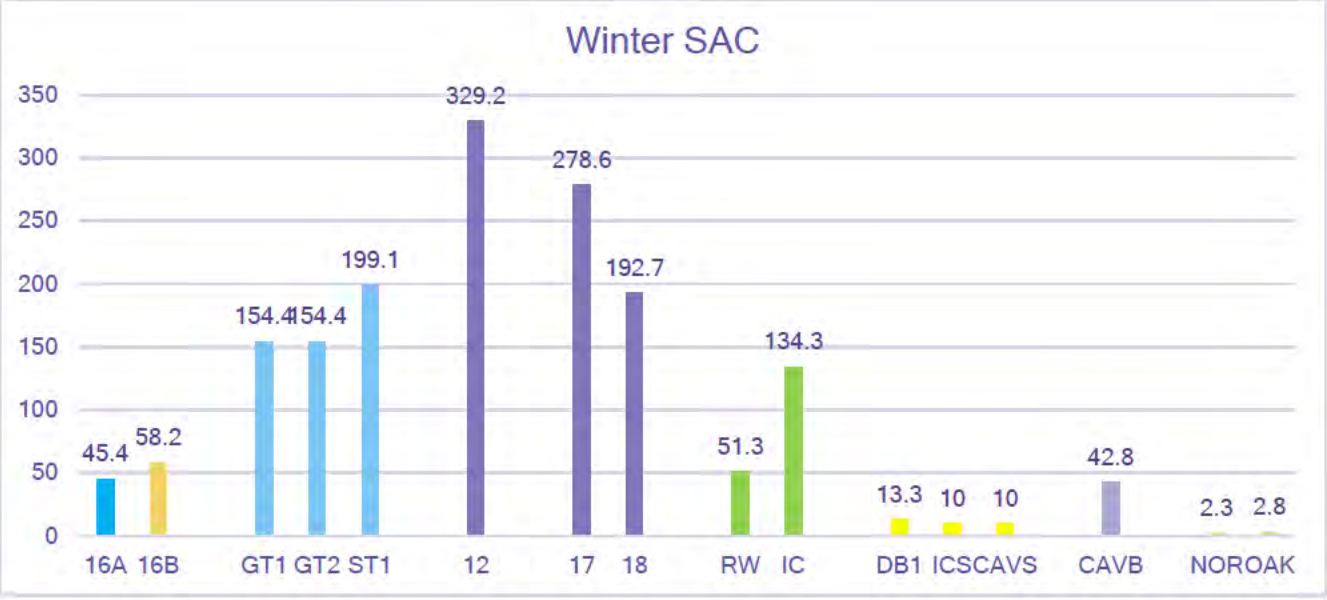


Figure 8E illustrates the SAC for NIPSCO's generating units for the spring season.

Figure 8E.

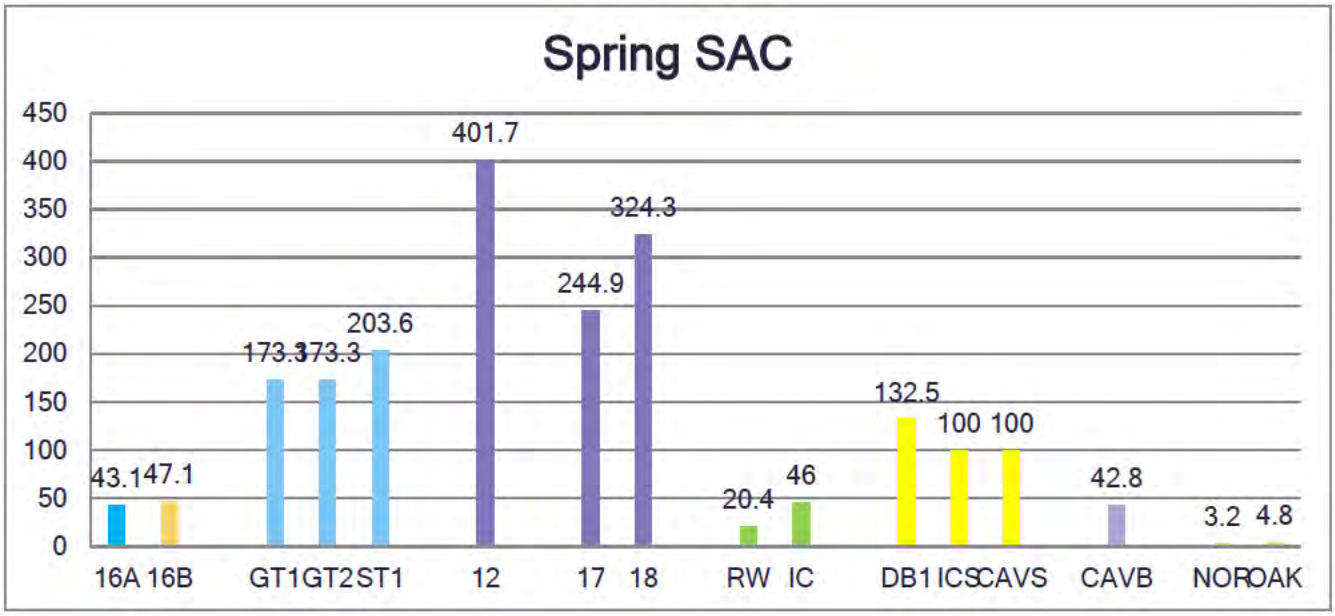
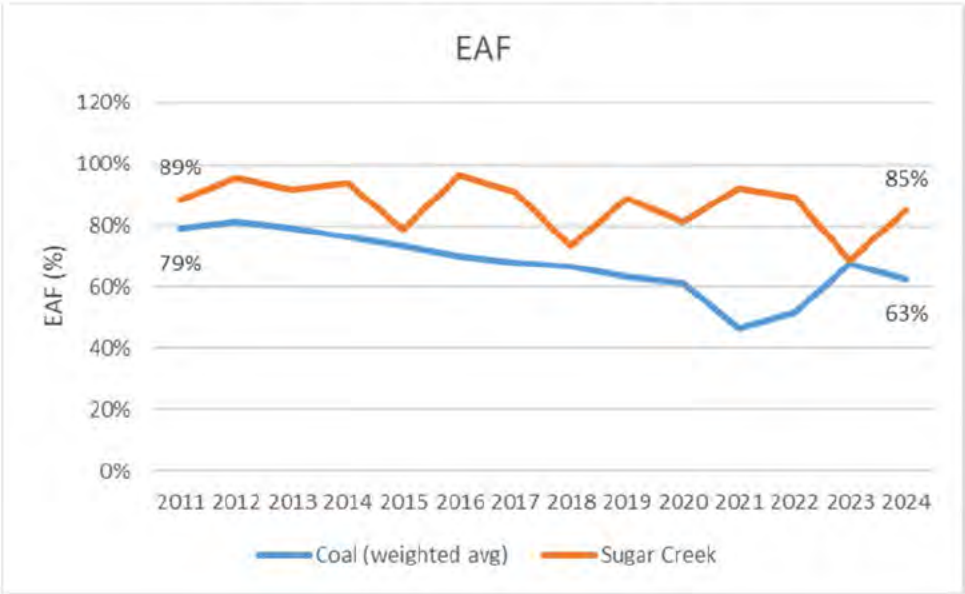


Figure 9 illustrates the equivalent availability factors ("EAF") of NIPSCO's coal and combined cycle units.[5] This metric represents the percentage of time a unit was available to generate power. The "equivalent" part of the definition accounts for times in which the unit was derated, meaning it could generate power but not up to 100% of its potential.

Figure 9. Equivalent Availability Factor



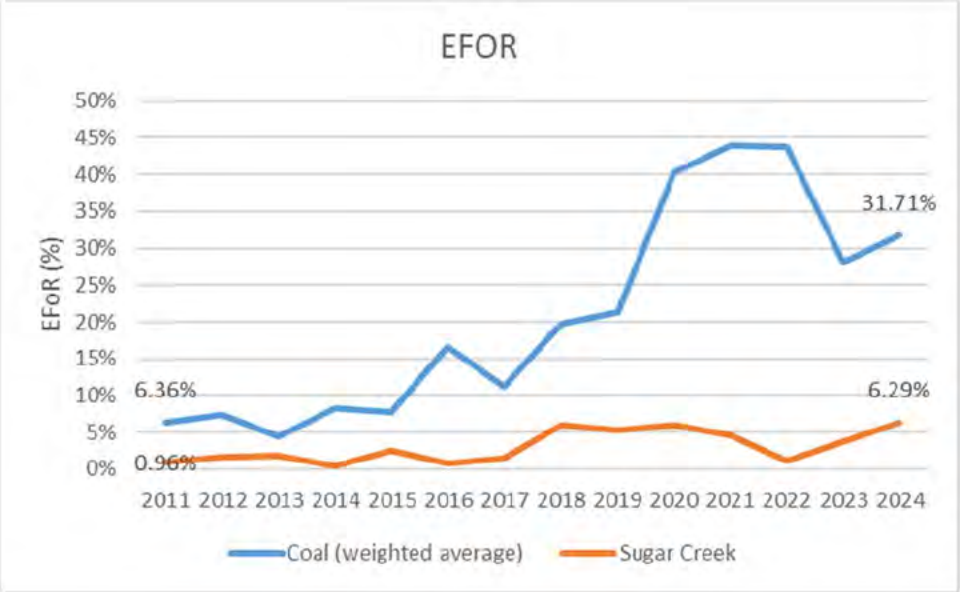
[5] EAF = [(Available Hours - Equiv. Planned Derate Hours - Equiv. Unplanned Derate Hours) / Period Hours] × 100%.

There has been an increase in forced and maintenance outages over the past 12 years, due to aging equipment and systems, which has reduced the EAF over this period. Maintenance outages are performed when energy demand is low and units may be removed from service without significantly impacting electric system capacity. Coal unit availability decreased slightly in 2024 due to more planned and maintenance outage hours spent preparing Schahfer units for their last year of operation. All other outage factors impacting availability were similar to those in 2023. Sugar Creek's availability increased in 2024, primarily due to a shorter planned outage period than the previous year. This allowed the units to be dispatched more in 2024.

Figure 10 illustrates NIPSCO's equivalent forced outage rate (EFOR), which represents the percentage of time (in hours) a unit was unable to generate power for reasons other than planned maintenance.

$$EFOR = \frac{FO + EFD}{FO + S + EFDRS} \times 100\%$$

Figure 10. EFOR[6]



A unit may be unable to generate power for reasons other than planned maintenance, when a forced outage (FO) occurs, or when a unit experiences an equivalent forced derate (EFD), in which a unit is unable to produce 100% of its typical capacity. The denominator in the

[6] Coal includes Michigan City Unit 12, and Schahfer Units 17 and 18.

equation is the sum of FO hours, service hours, and EFD hours, when the unit is in reserve shutdown.

NIPSCO's coal EFOR has been significantly affected by changing power markets, which has changed the economical dispatch for coal. Infrequent operation for years, which imposes high thermal stresses on a unit, leading to an increase in forced and maintenance outage hours, followed by an increase in the demand for operating hours later in the year, exacerbates the issues. The coal EFOR increased slightly in 2024. Although the forced outage hours decreased from 2023, fewer service hours caused the EFOR uptick, due to units not being dispatched as often and an increase in planned and maintenance outage hours in 2024.

Sugar Creek's EFOR increased from 3.72% in 2023 to 6.29% in 2024. The primary reason for the slight uptick in EFOR from 2023 was tube and steam leaks on the heat recovery steam generator. Sugar Creek had three such events in 2024. Additionally, CT 1A was out of service for the first 24 days in January due to rotor damage caused by a contractor that carried over from the Winter planned outage in 2023.

Figure 11. **Coal Generation**[7]

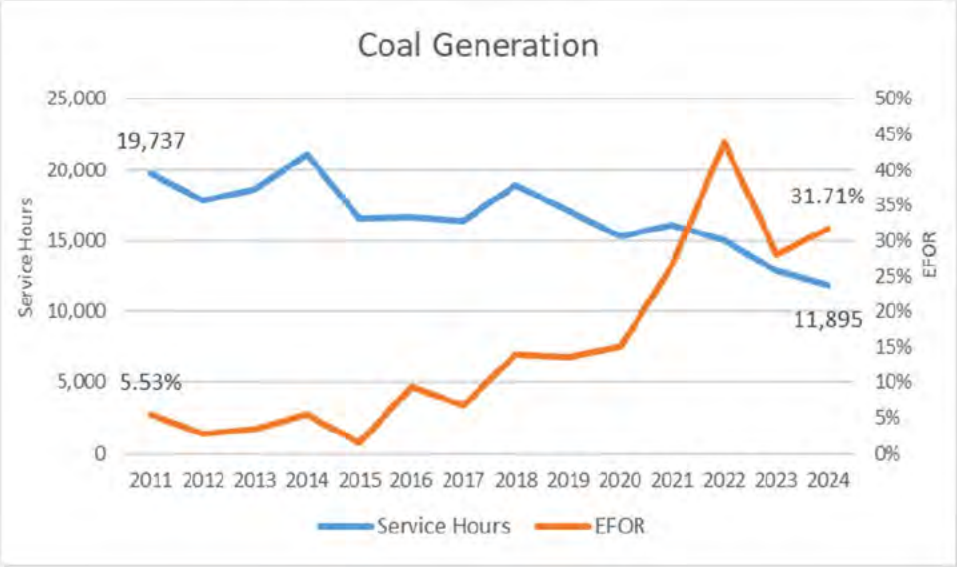


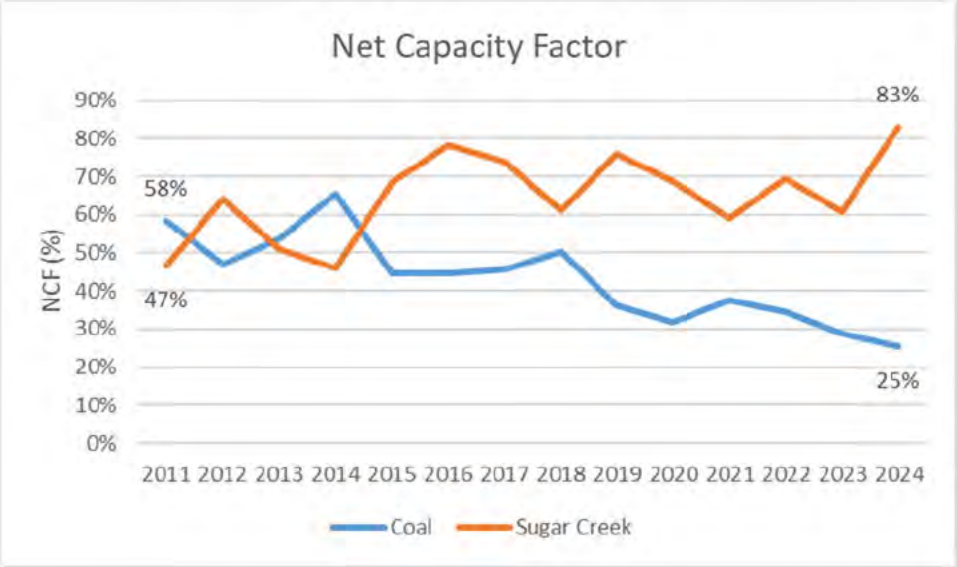
Figure 11 illustrates the relationship between the total service hours of NIPSCO's coal generation and the EFOR of those units. All things being equal, as service hours decrease over time, the EFOR increases. If a unit is available but not dispatched, the EFOR remains

[7] Service hours include only Michigan Unit 12 and Schahfer Units 17 and 18.

static. In 2024, the service hours remained low, primarily due to being dispatched less and more planned and maintenance outage hours in 2024.

Figure 12 illustrates the net capacity factor ("NCF") of NIPSCO's fossil fuel units. This metric represents the percentage of a unit's full capacity that it is allowed to produce, on average, during the period.

Figure 12. **Net Capacity Factor**[8]



NCF is a function of a unit's availability and its variable operating costs. A unit that has frequent forced or planned outages, or high operating costs compared to other generating units, will have a lower capacity factor. A unit's NCF is affected by the amount of time it is available to run, but has not been selected, due to economics. A unit that is always available to generate and has competitive operating costs will have a higher capacity factor. This largely explains why NIPSCO's gas-fired units at Sugar Creek have a much higher NCF than its coal-fired units. The coal capacity factor continues to decrease year-over-year, due to being dispatched less, as more renewable assets are commissioned.

[8] Generating units continue to consume a small amount of power even when they are not generating energy. This auxiliary power is subtracted from a unit's generation total and decreases the unit's NCF. Coal includes only Michigan City Unit 12 and Schahfer Units 17 and 18.

Renewable Generation

Figure 13 illustrates the NCF of NIPSCO's wind assets. Rosewater had a lower than forecasted NCF for 2024 due to lower than forecasted wind resources and turbine main bearing repairs. Indiana Crossroads Wind I had a lower than forecasted NCF as well due to lower than forecasted wind resources because of variability in the forecasted weather which resulted in lower wind than forecasted.

Figure 13. **Wind Net Capacity Factor (NCF)**

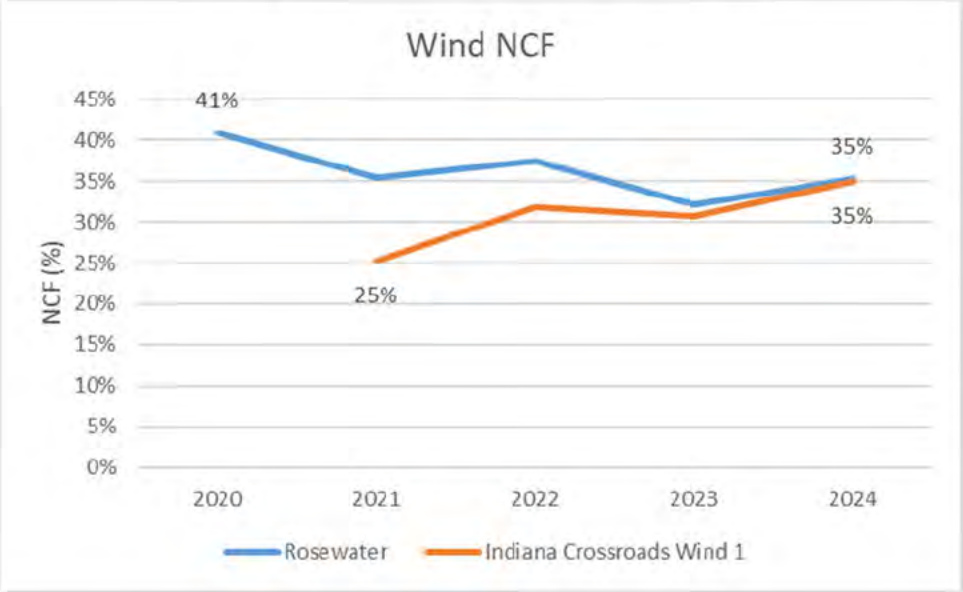


Figure 14 illustrates the NCF of NIPSCO's solar assets. Indiana Crossroads Solar and Dunns Bridge I had lower than forecasted NCF for 2024 due to inverter reliability issues. Cavalry Solar, which became operational in May 2024, had a lower than forecasted NCF due to PV panel replacements and post construction activities.

Figure 14. **Solar Net Capacity Factor (NCF)**

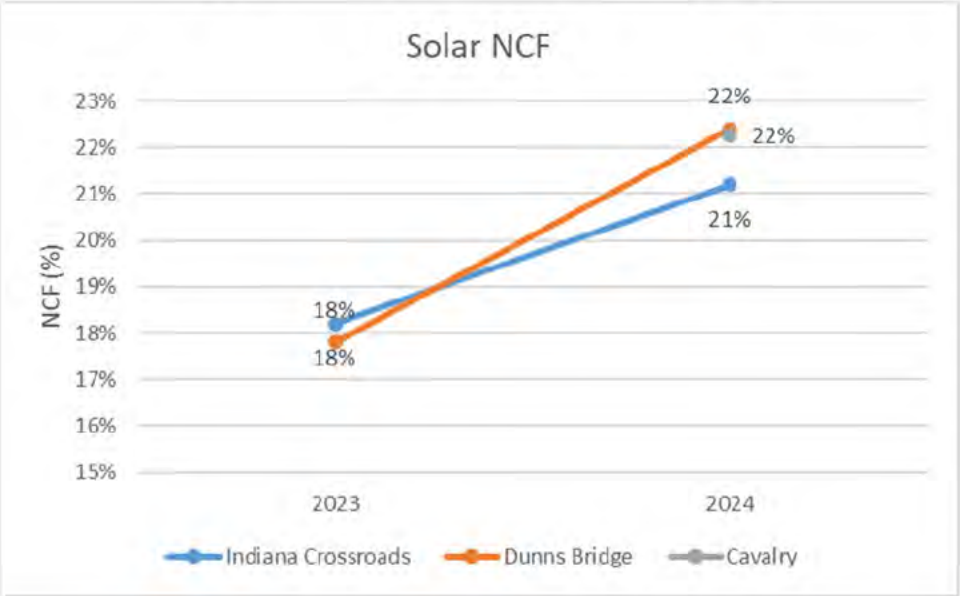


Figure 15 illustrates the Gross Energy Availability ("GEA") of NIPSCO's wind assets. This metric represents the facilities' potential to produce energy considering all downtime events. This metric is calculated as actual production divided by the sum of actual production and lost production due to downtime or curtailment restrictions. Both wind farms had a higher than forecasted GEA due to minimal gross losses with respect to forecast.

Figure 15. **Wind Gross Energy Availability**

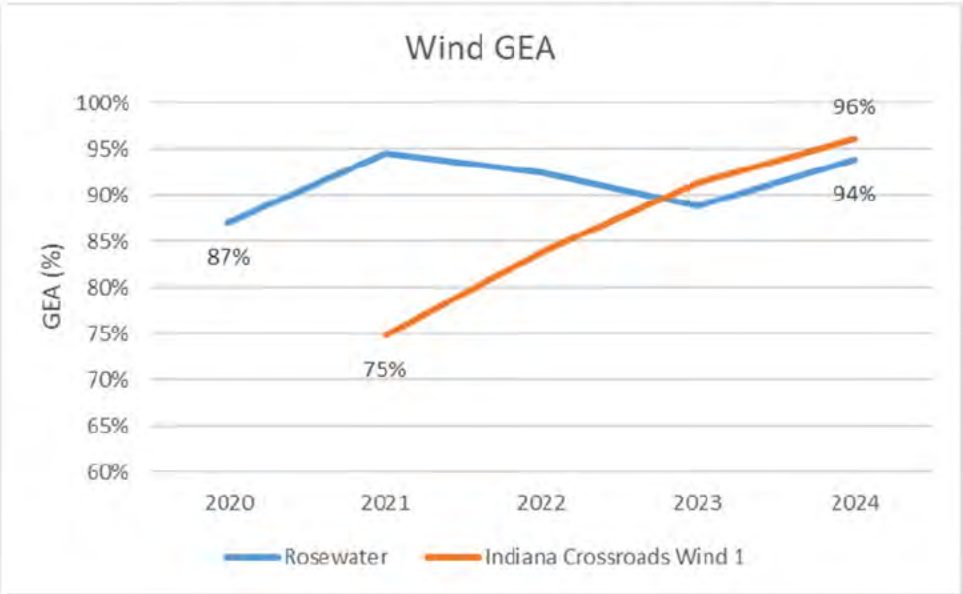


Figure 16 illustrates the Net Performance Ratio ("NPR") of NIPSCO's solar assets. This metric is the ratio of the actual generation compared to the theoretical maximum generation

based on the DC nameplate capacity. This metric is calculated as the actual production divided by the theoretical maximum generation due to irradiance and PV panel temperatures. Indiana Crossroads Solar and Dunns Bridge I had a lower than forecasted NPR in 2024 due to inverter reliability issues. Inverter retrofits have taken place at the majority of our facilities and will be fully complete by Q3 2025. These retrofits will increase the equipment-related reliability of our fleet and increase our NPR. These retrofits are covered under warranty by the Original Equipment Manufacturer. Cavalry had a lower than forecasted NPR in 2024 due to PV panel replacements and post construction activities.

Figure 16. **Solar Net Performance Ratio**

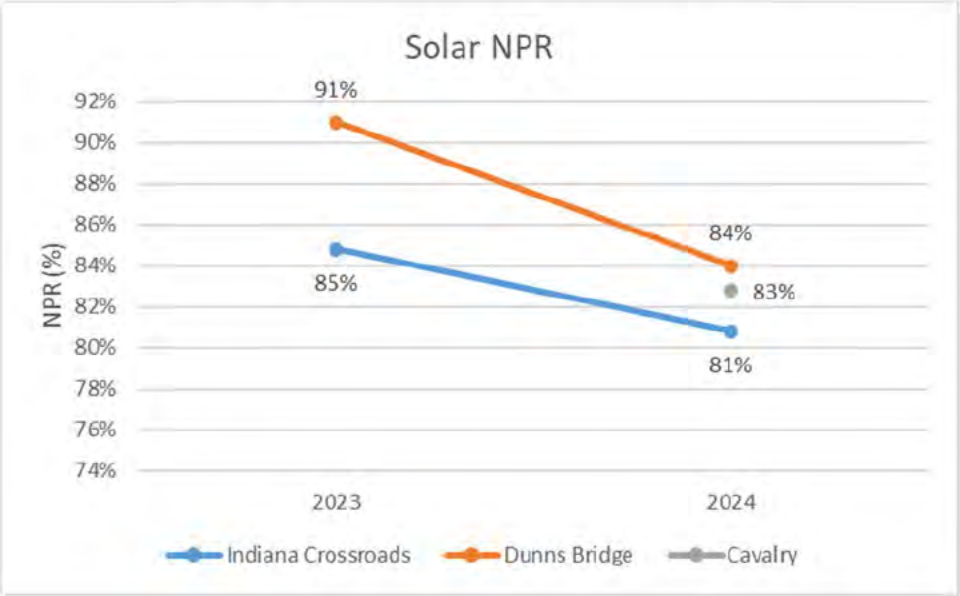


Figure 17 illustrates the Technical Energy Availability ("TEA") of NIPSCO's wind assets. This metric represents the facilities' potential to produce energy, considering downtime caused by turbine and balance of plant events, and excludes environmental, grid, and curtailment events. It is calculated as actual production divided by the sum of actual production and lost production due to technical downtime. Rosewater had a lower than forecasted TEA for 2024 due to main bearing repairs. Indiana Crossroads Wind I had a higher than forecasted TEA due to minimal technical losses.

Figure 17. **Wind Technical Energy Availability**

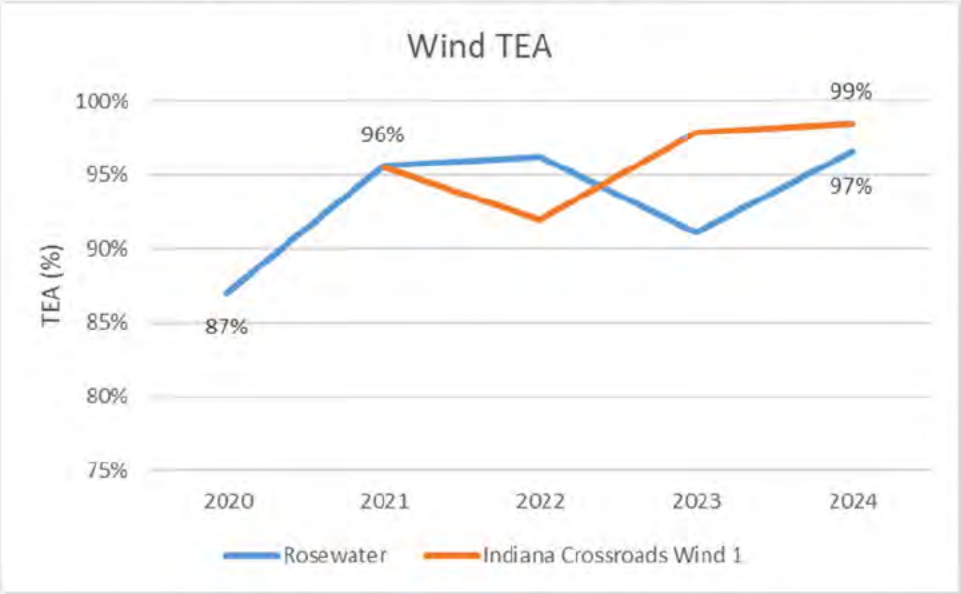
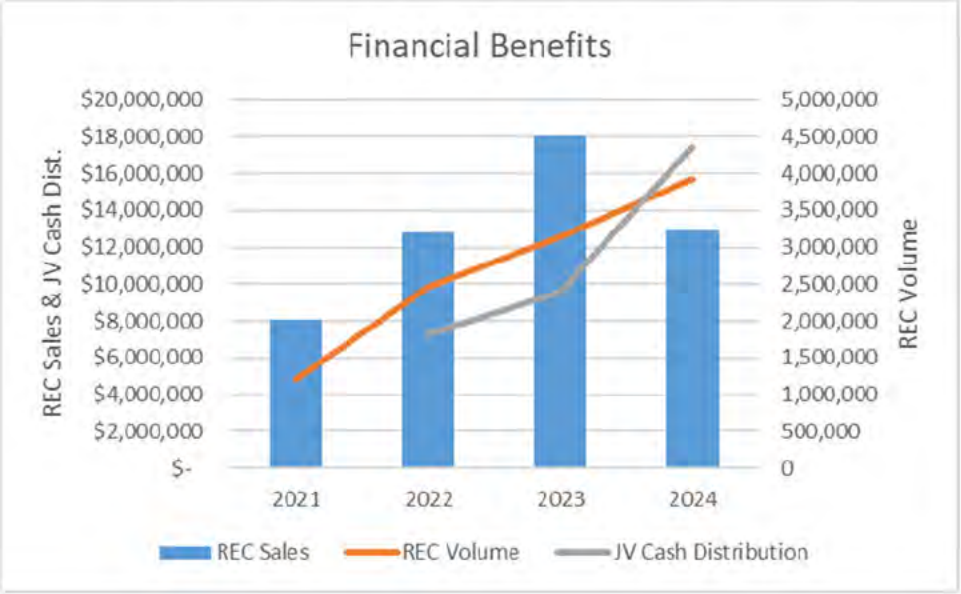


Figure 18 shows the financial benefits flowing back to customers associated with renewable projects that NIPSCO has brought online since 2020.

Figure 18. **Financial Benefits Flowing Back to Customers**



Renewable Energy Credit (REC) Sales - Each megawatt hour of power generated from a qualified resource can be awarded a REC. Many state jurisdictions require sellers of renewable power to have such RECs to certify that the source is in fact a qualified renewable resource. The amount of sales listed in Figure 18 includes all RECs sold by NIPSCO, including those coming from wholesale purchase power agreements, joint ventures with a tax

equity partner, and wholly owned solar facilities. The 2024 volume is higher than 2023, however, 2024 experienced a significant dip in pricing, lowering the overall amount for REC sales. Note: Rosewater Wind and Jordan Creek Wind were NIPSCO's first renewable energy projects, starting near the end of 2020. While these projects generated REC sales in 2020, they were not significant enough to include on this graph.

Joint Venture (JV) Cash Distribution – When the proceeds from a power purchase agreement between NIPSCO and the applicable JV exceed the JV's operating costs (and after a certain amount of contingency has accumulated), NIPSCO passes back the excess funds to its customers, serving as a direct reduction to FAC costs on a dollar-for-dollar basis.

DISTRIBUTED GENERATION

As part of NIPSCO's Cause No. 45772 settlement agreement, NIPSCO agreed to provide data related to distributed generation in its PMC Report. Specifically, NIPSCO agreed to provide monthly customer participation data for NIPSCO's Excess Distributed Generation (EDG) tariff and Small Power Production tariff, broken down by residential and non-residential customers, including data on both new and total (a) capacity (kW-ac) installed, (b) number of customers, and (c) size of battery storage system (both kW and kWh), if one is part of the customer's system.

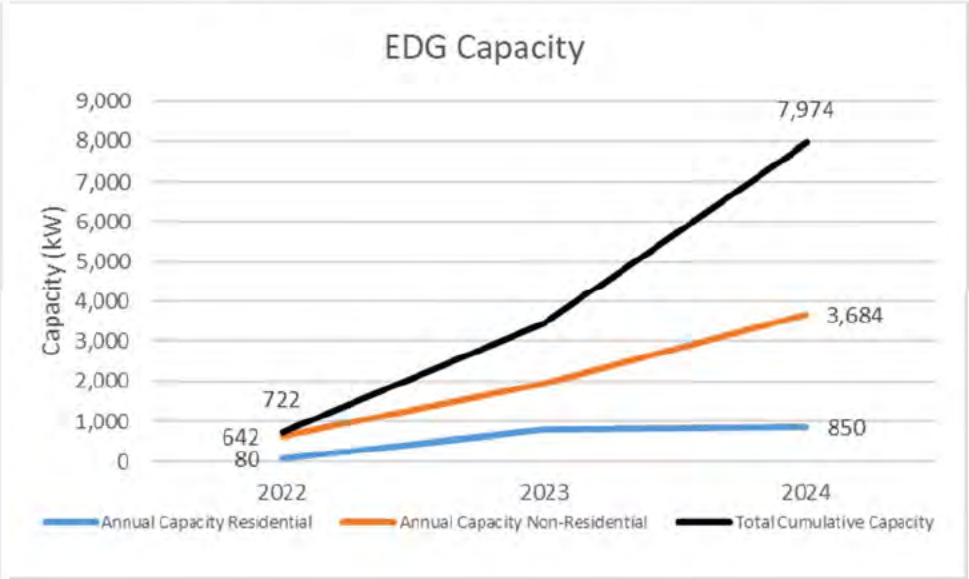
2024 monthly metrics are shown in Figure 19. NIPSCO showed increases in capacity installed, number of customers, and amount of battery storage in 2024, compared to 2023. NIPSCO has also included a cumulative row at the bottom of Figure 19, to show total EDG metrics as of 2024.

Figure 19. **Excess Distributed Generation - 2024 - Monthly Data**

2024 EDG								
	Non-Residential				Residential			
	Number of Customers	Total Capacity (kW)	Battery Storage		Number of Customers	Total Capacity (kW)	Battery Storage	
			kW	kWh			kW	kWh
Jan	11	91.9			3	264.6		
Feb	2	45.6			10	78.7	13.5	27
Mar	1	300			4	31.7		
Apr	1	125			6	36.5	3.8	10.5
May	3	100			8	55.9	8.7	17.6
Jun	5	520			7	45.9		
Jul	2	31.4	20	19.4	9	70	5	10
Aug	6	638.7			6	28.4	3.8	10.5
Sep	0	0			1	6.4		
Oct	5	101.5			6	91.8		
Nov	1	500			4	43.3	10	20
Dec	6	1229.6			12	96.6	38.5	61.3
2024	43	3683.7	20	19.4	76	849.8	83.3	156.9
Cumulative	66	6267.3	24.5	28.4	159	1706.6	183.1	357.7

Figure 19A illustrates the total capacity for residential and non-residential, as well as the cumulative capacity.

Figure 19A. Excess Distributed Generation



Small Power Production

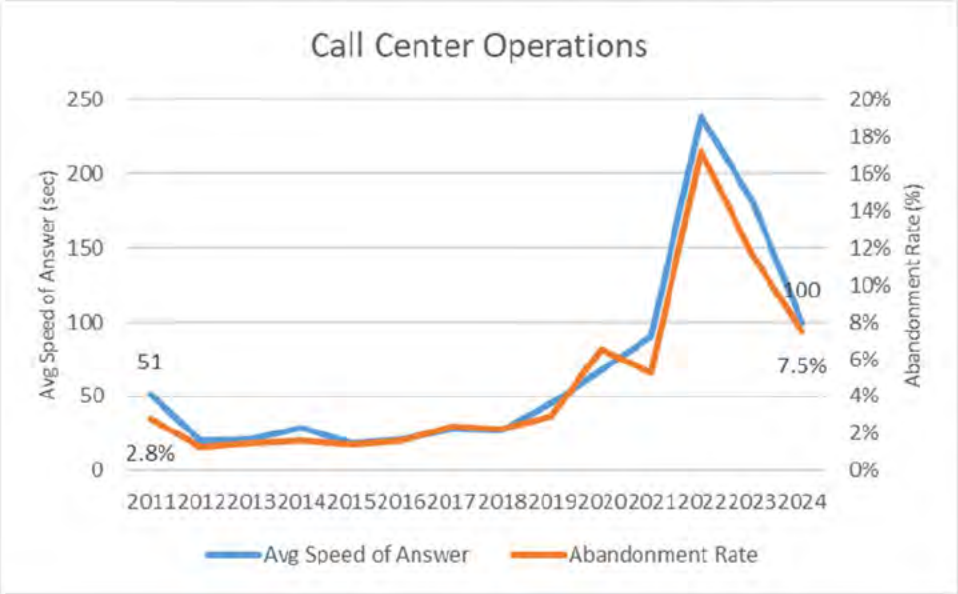
In 2024, NIPSCO had two customers added to Rider 578 – Purchases from Cogeneration Facilities and Small Power Production Facilities. Both customers are grocery stores and contracted for no capacity, with the intention to use the power generation onsite.

CUSTOMER SERVICE

NIPSCO's highest priority is the delivery of safe, reliable service to customers. NIPSCO strives to respond to the needs of its customers in the communities it serves across Northern Indiana. The Company regularly benchmarks and measures the success of its customer service efforts to continually improve on processes and scores.

Figure 20 shows NIPSCO's average speed of answer and abandonment rates.

Figure 20. Call Center Operations



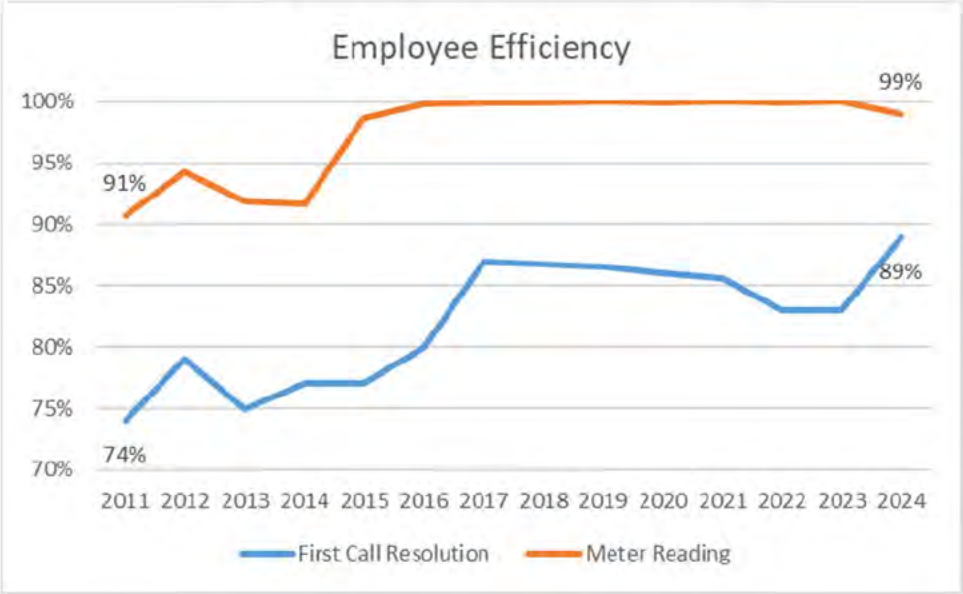
The average speed of answer ("ASA") metric represents the average number of seconds a caller waits before their call is answered by a Customer Service Representative ("CSR"), exclusive of the time a caller is navigating through the interactive voice response ("IVR") phone system. The decrease in ASA in 2023 was due to a reduction in calls routing to the CSR and improved attrition. NIPSCO saw a 12% reduction in call volume routing to a CSR due to customers becoming more accustomed to the IVR system, which was installed in 2022, therefore meeting their own self-service needs, an improvement in routing customers to make payments, and fuel costs stabilizing as 2023 progressed. This trend continued in 2024 with the ASA decreasing from 182 in 2023 to 100 in 2024.

The abandonment rate represents the percentage of telephone calls that are ended by customers before speaking with a CSR. The call center telephone system informs customers of their estimated wait time to speak to a CSR and gives them the option to receive a "virtual

callback", in which Virtual Hold technology autodials the customer in the order that the customer called, whenever a CSR is available for the next caller. The abandonment rate decreased by 5.5% in 2023, for the same reasons noted above for the ASA improvement and decreased again in 2024 by 4.1%.

Figure 21 shows NIPSCO's first call resolution and meter reading rates. The customer satisfaction metrics shown in Figure 22 are both indirectly related to the two metrics shown in Figure 21.

Figure 21. **Employee Efficiency**



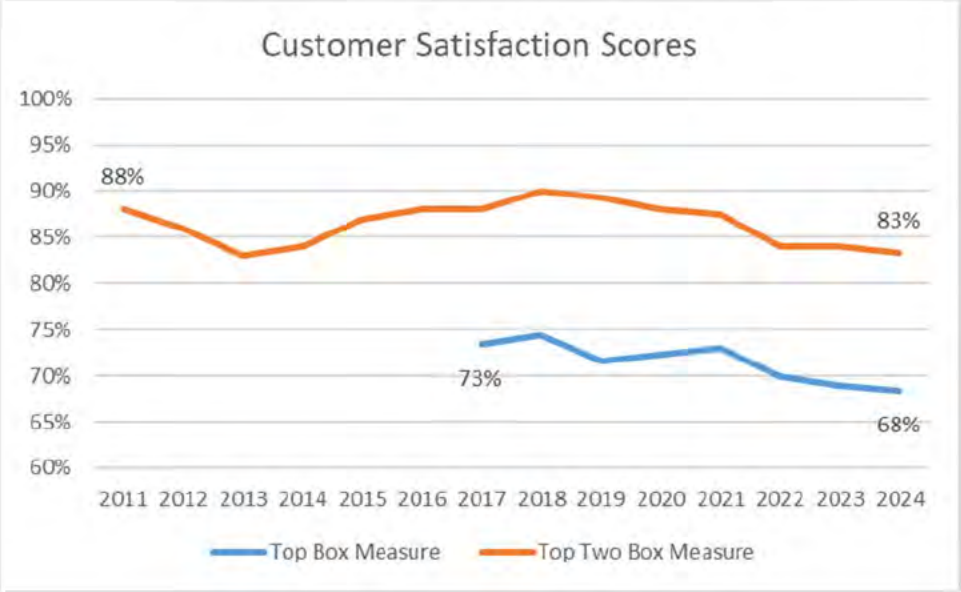
The first call resolution metric is measured by an outside vendor and represents how often NIPSCO is able to meet a customer's needs during the first telephone call. Customers highly value the ability of NIPSCO to resolve their issues quickly. NIPSCO continues to be above the 80% range for this metric, increasing from 83% in 2023 to 89% in 2024.

The meter reading metric represents the percentage of NIPSCO's residential and commercial electric meters that the Company accurately reads each month. The rollout of the Company's automated meter reader program in 2015 and 2016 accounts for the significant improvement in this area since 2014 and the transition to Electric Automated Metering Infrastructure (AMI) began in 2024.

Customer Satisfaction

Figure 22 shows NIPSCO's customer satisfaction scores. NIPSCO engages a third party to measure how well the Company interacts with its customers. The customer satisfaction (CSAT) score reflects the average customer experience when they interact with: (1) a CSR on the phone; (2) the IVR phone system; (3) an employee on the customer's property; or (4) NIPSCO's self-service website. NIPSCO's CSAT saw a decline in 2024, due to lower satisfaction with property restorations. The CSAT metric is inclusive of both gas and electric customer experience. NIPSCO incorporated the CSAT score into its corporate incentive plan calculation in 2017, as part of its commitment to customer service.

Figure 22. Customer Satisfaction Scores



In 2024, NIPSCO saw satisfaction increase over 2023 satisfaction, for the customer service representatives, the IVR (automated phone system), and the online self-service web experiences. However, NIPSCO saw a slight decline in satisfaction for field operations, specifically relating to property restorations. The decline in field operations satisfaction scores in 2024 was minor and was driven by limited communication and delays in property restoration after completed work. NIPSCO has engaged in a multi-year project, focused on improving the communication and property restoration process, which has included engaging with customers to better understand their expectations and receiving feedback for making improvements to the property restoration process.

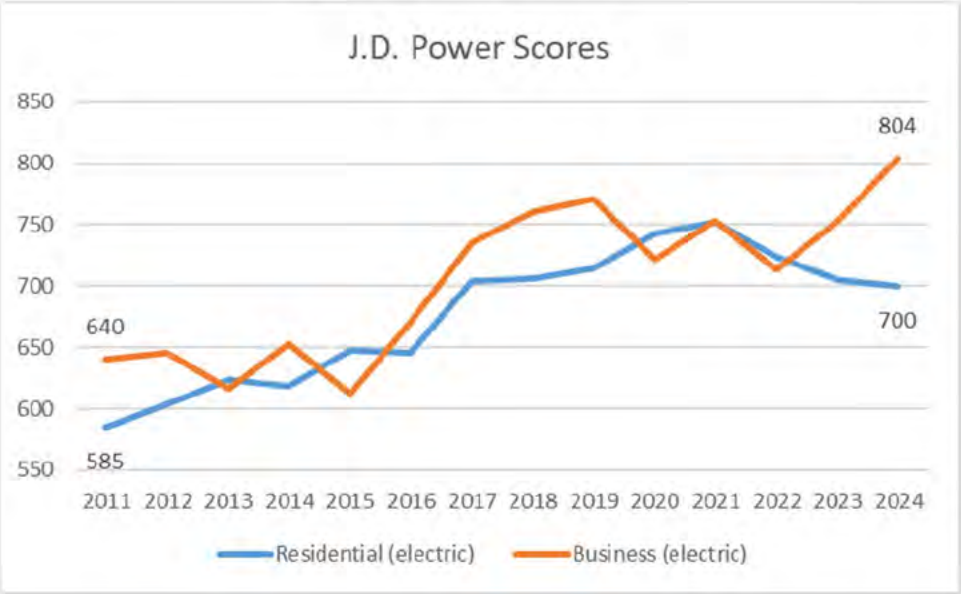
Prior to 2015, the CSAT score primarily reflected customers' interactions with NIPSCO's call center, and customers were only asked one question. The Company modified its satisfaction survey in 2015 to better measure its performance in discreet channels and weighted each channel's score according to the number of surveys completed for that channel. NIPSCO has found that measuring customer satisfaction in different channels better identifies successful practices and opportunities for improvement.

In 2017, NIPSCO retained a new vendor and made three significant changes to determining the CSAT score. First, customers were allowed to complete online surveys, whereas all surveys had previously been conducted over the telephone. Second, NIPSCO began weighting each communication channel equally in the CSAT score calculation. Third, the Company switched from quantitative responses (1-10) to qualitative responses (such as "I am somewhat satisfied").

In 2022, NIPSCO changed the standard of measurement for customer satisfaction to align with NIPSCO's goal of providing a top tier customer experience. Prior to 2022, customer satisfaction was measured and reported as a top-two box measure – very satisfied or somewhat satisfied. The reported score was the percentage of customers who responded within those two box measures. In 2022, the customer satisfaction metric was changed to a top-box metric – very satisfied. The reported score is now the percentage of customers who responded within the top box measure. So as not to skew the metric, Figure 22 illustrates the CSAT score for both calculations. NIPSCO does not have data available for the top-box measure prior to 2017.

Figure 23 illustrates the J.D. Power Electric Utility scores for residential and business customers. The J.D. Power Electric Utility Customer Satisfaction studies examine residential and business customer satisfaction across six factors – power quality and reliability, price, billing and payment, communications, corporate citizenship, and customer service. In 2024, NIPSCO saw an increase in overall satisfaction for business customers, while residential customer satisfaction decreased slightly from a peak high in 2021.

Figure 23. **J.D. Power Scores**



In demonstration of NIPSCO's improvement and overall focus on serving customers, the 2024 J.D. Power Residential Customer satisfaction survey for the Midwest region of midsize utilities scores NIPSCO at 700, which is above the group average of 692 and the highest of the three Indiana electric investor-owned utilities in the segment. In J.D. Power's Business Customer satisfaction survey, NIPSCO received a score of 804, which is above the group average of 779, and the highest out of Indiana's three electric investor-owned utilities in the segment.

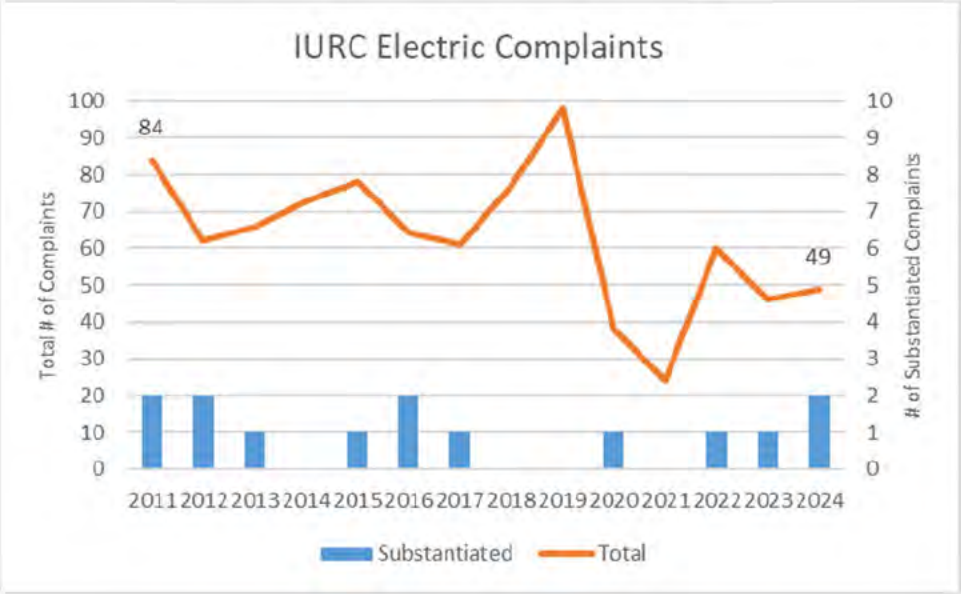
While NIPSCO subscribes to the J.D. Power Business satisfaction survey and that is the main reporting metric in this report, additional input and feedback is needed from customers to help the Company identify key opportunities for improved customer service. The J.D. Power Business satisfaction survey is (1) a perception-based survey with slightly more than 100 NIPSCO Business customer respondents each year, many of whom may not have had a recent interaction with the Company, and (2) focused on small- to medium-sized businesses and is not a representative tool to gauge the satisfaction or opportunities for improvement related to NIPSCO's large customers.

In 2021, as part of its efforts to continue to enhance its relationship and service to commercial/industrial customers, NIPSCO hired an independent market research group (MSR Group) to survey NIPSCO's large business accounts on an annual basis, to help the Company focus its efforts related to this group of customers. This metric is based on

customer satisfaction with NIPSCO account managers and improved from 81% in 2021 to 95% in 2023, remaining relatively flat for 2024 at 93.8%.

Figure 24 illustrates the number of electric complaints filed with the Commission against NIPSCO and the number of complaints that were substantiated. Utility customers in Indiana may file a complaint with the Commission if they feel aggrieved. The Commission's Consumer Affairs Division investigates each complaint and determines whether the complaint is substantiated. In 2024, NIPSCO received two substantiated complaints. The number of complaints came from a broad array of service category types.

Figure 24. **IURC Electric Complaints**



INVESTMENT AND SPENDING

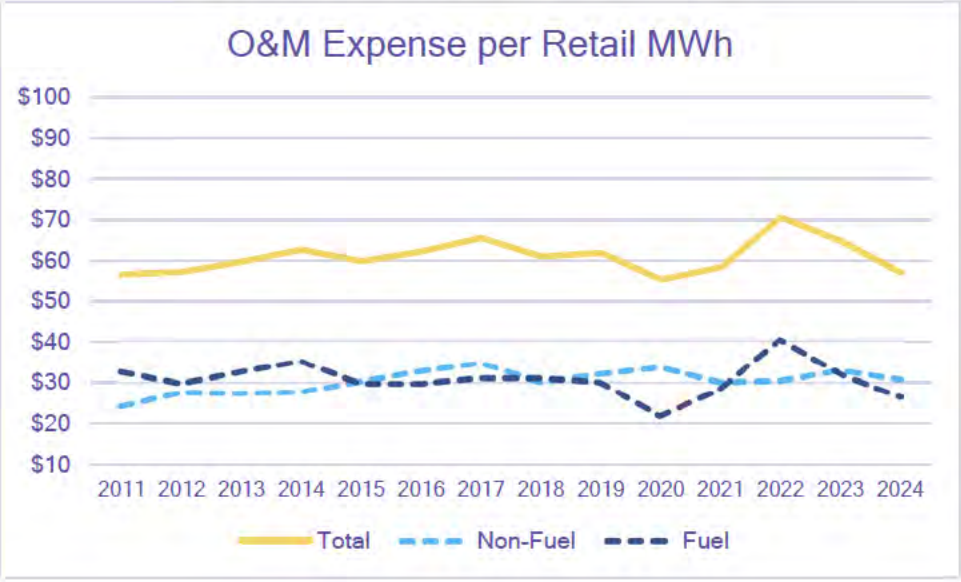
This section analyzes NIPSCO's operations and maintenance ("O&M") expense. The data is the same as the data included in NIPSCO's Federal Energy Regulatory Commission (FERC) Form 1.

The Electric O&M Expense section of NIPSCO's FERC Form 1 is divided into eight parts. Part 1 covers power production, which is divided into steam, nuclear, hydro, and other (gas). Parts 2-4 cover power delivery functions: transmission, regional market, and distribution. Parts 5-7 cover customer service and Part 8 covers corporate administration.

In this report, megawatt hours ("MWh") represent either retail sales (Figures 25, 26, 31, 32, 33, 34, and 35), or total sales including sales for resale (Figures 27, 28, 29, and 30), with the legends marked accordingly. Figure 27 also expresses non-fuel production O&M expense as a function of MWh generated by the utility. The "non-fuel" numerators exclude Accounts 501 (steam fuel), 547 (other generation fuel), and 555 (purchased power). Figure 28 also expresses transmission O&M expense as a function of line miles. These accounts can be found on pages 320 and 321 of NIPSCO's FERC Form 1.

Total O&M

Figure 25. **O&M Expense per Retail MWh**[9]



[9] FERC Form 1, Page 323, line 198 / Page 301, line 10 (d).

Figure 25 illustrates O&M expense per retail megawatt hour.

Figure 26. **O&M Expense per Retail Customer**[10]

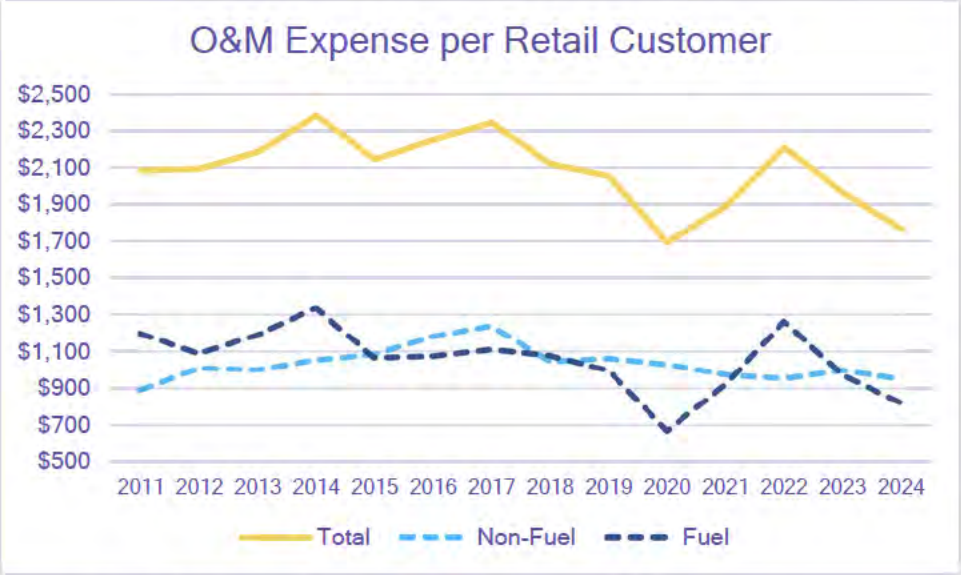


Figure 26 illustrates O&M expense per retail customer.

O&M Components

Figure 27. **Non-Fuel Production O&M Expense**[11]

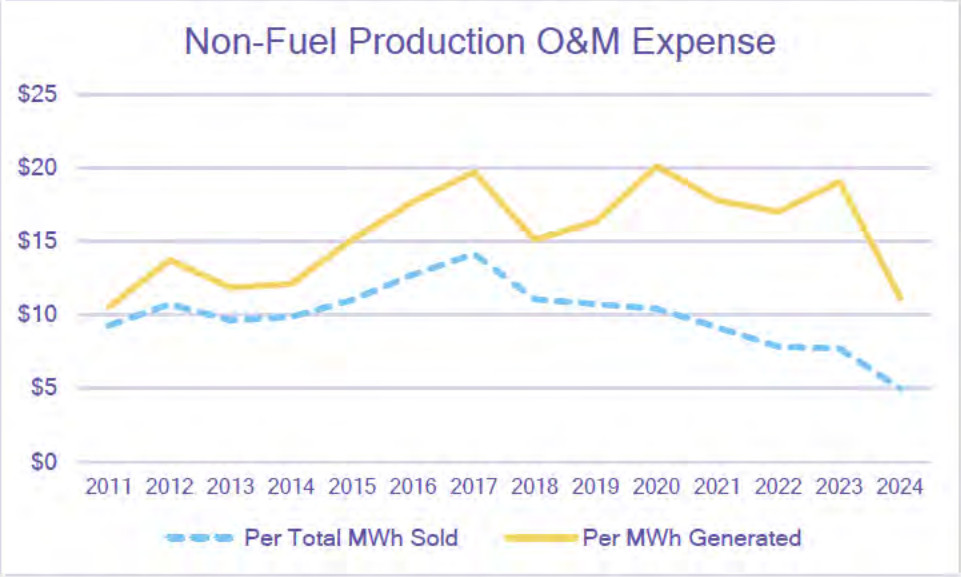


Figure 27 illustrates NIPSCO's non-fuel production O&M expense.

[10] FERC Form 1, Page 323, line 198 / Page 301, line 10(f).
[11] FERC Form 1, Page 321, line 80- lines 5, 25, 63, and 76 / Page 301, line 12(d); per MWh generated uses Page 401a. line 9.

Figure 28. **Transmission and Distribution O&M Expense[12]**

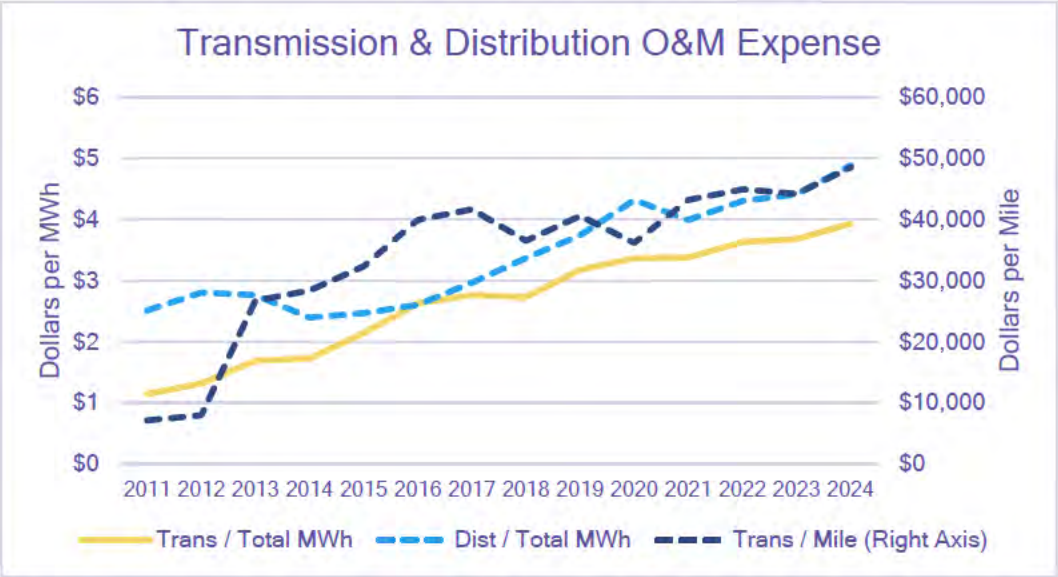


Figure 28 shows NIPSCO's transmission and distribution expenses as a function of total energy sales, and transmission expenses as a function of line miles. In 2013, NIPSCO reclassified its 69 kV circuit miles from transmission to distribution in accordance with FERC's seven-factor test.

The principal driver of transmission expense during this period has been Account 561.8, Reliability, Planning, and Standards Development Services. This account reflects the costs of three regional transmission expansion project (TEP) types that MISO has billed to NIPSCO through Schedule 26. The Commission authorized NIPSCO to begin recovering these costs through the utility's Regional Transmission Organization tracker (Rider 871) in 2012.

The largest component of distribution expense each year is Account 593, Maintenance of Overhead Lines, which has averaged greater than 50% of the total expenses in this category since 2013. The reliability section of this report discusses how NIPSCO's investment in vegetation management in recent years has positively affected its reliability indices.

[12] FERC Form 1, Transmission (Page 321 line 112); distribution (Page 322, line 156) / MWh (Page 301, line 12(d); per pole mile uses (Page 422, line 36).

Figure 29. **Customer O&M Expense per Total MWh[13]**

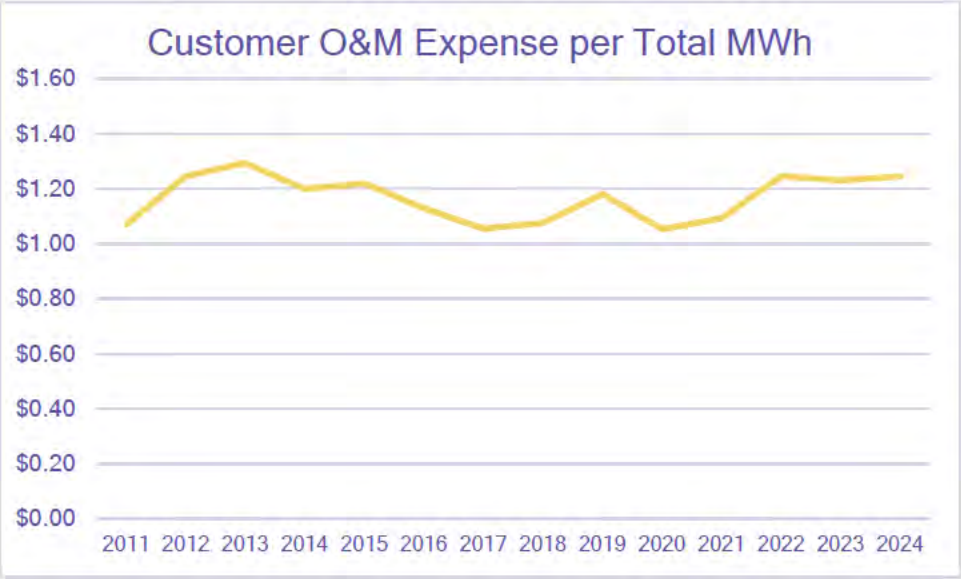


Figure 29 illustrates the customer O&M expense per total MWh. Customer expense accounts in FERC Form 1 are organized into three parts: customer accounts, customer service and information, and sales. Figure 29 illustrates the sum of these accounts divided by total sales. The decline in 2020 was mostly driven by changes in spending related to COVID-19 and by reduced load, and costs have since increased to levels slightly above those in 2019.

Administrative and General ("A&G") expenses are the final O&M component shown in FERC Form 1. This part includes accounts such as A&G salaries, office expenses, outside services employed, and employee pensions and benefits. These expenses are primarily fixed, meaning they do not rise and fall in the short run with changes in sales levels.

[13] FERC Form 1, Page 323, line 164 + line 171 + line 178 / Page 301, line 12(d).

Figure 30. **A&G O&M Expense per Total MWh[14]**

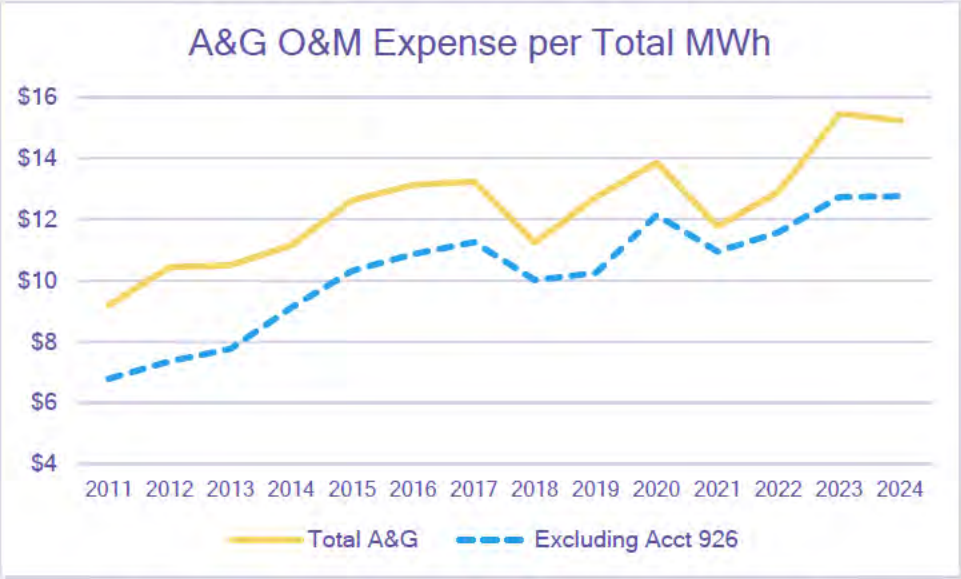
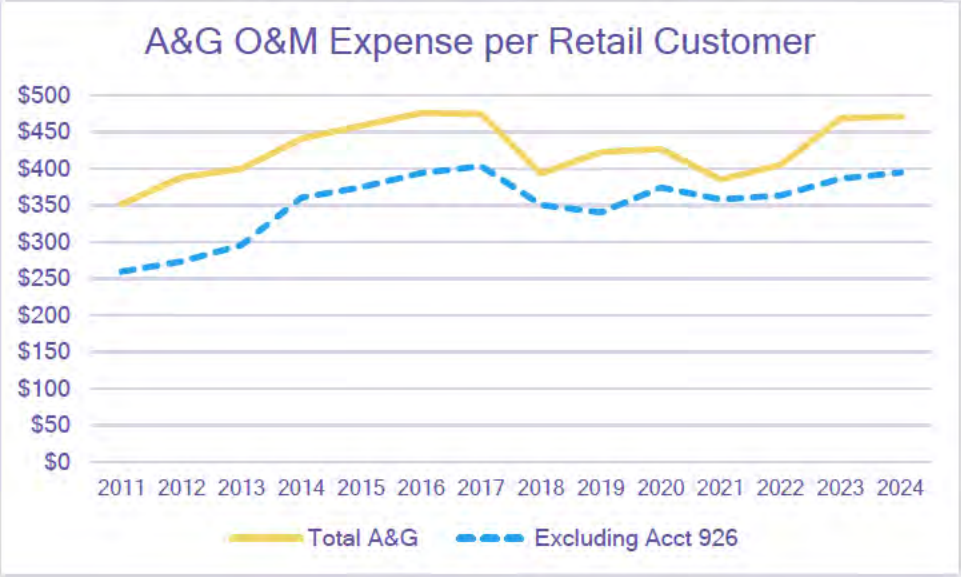


Figure 31. **A&G O&M Expense per Retail Customer[15]**



Figures 30 and 31 show A&G expenses as a function of total sales and retail customers. The figures also represent the metrics without Account 926, Employee Pensions and Benefits. This account is largely driven by interest rates and investment returns, two functions significantly outside of the utility's control.

[14] FERC Form 1, Page 323, line 197 / Page 301, line 12(d); Acct 926 is Employee Pensions and Benefits expense (Page 323, line 187).
[15] FERC Form 1, Page 323, line 197 / Page 301, line 12(f); Acct 926 is Employee Pensions and Benefits expense (Page 323, line 187).

Benchmarking Analysis

This section illustrates the respective metrics of NIPSCO and the median Indiana electric investor-owned utilities against nationally comparable data. The data of the 20% of U.S. utilities with the lowest (best) metrics (i.e., the first quintile) is represented within the light blue section at the bottom of each graph. Each colored area above the first quintile represents a successive quintile.[16]

Figure 32. **O&M Expense per Retail MWh**

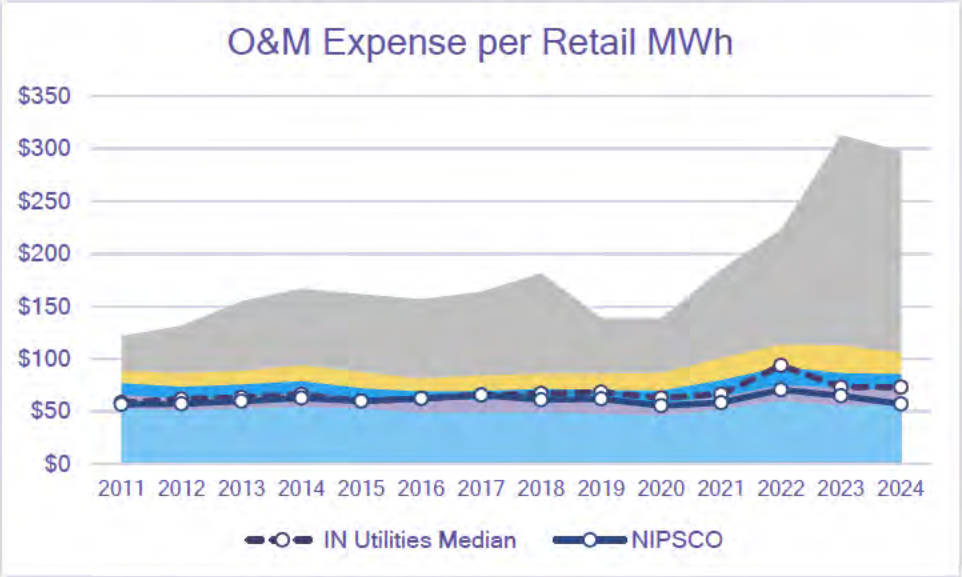
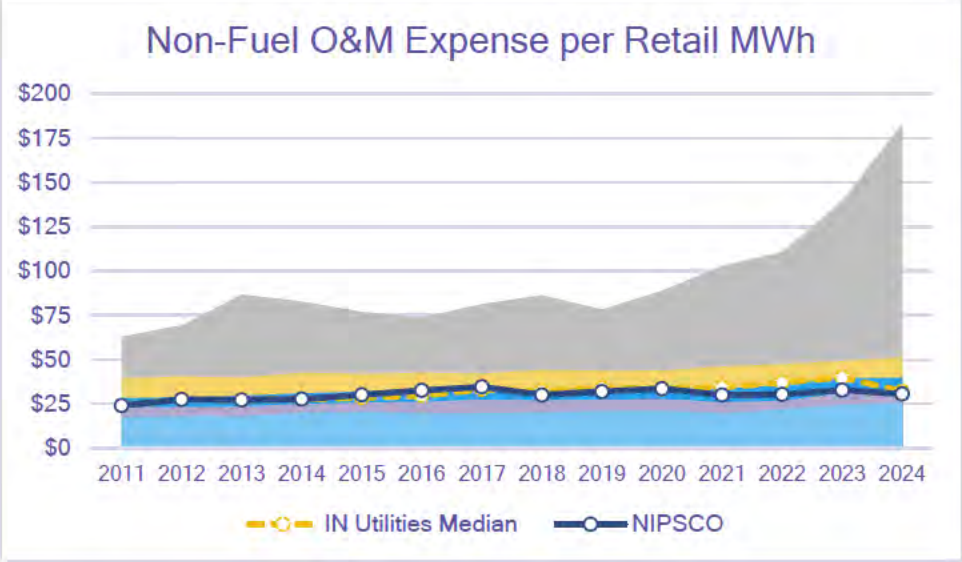


Figure 32 illustrates the O&M expense per retail megawatt hour.

Figure 33. **Non-Fuel O&M Expense per Retail MWh**



[16] The 5th quintile (i.e., grey shaded area) represents the 95th percentile of U.S. utilities. The top 5% of U.S. utilities with the highest (worst performing) metrics are treated as outliers and not presented in the graphic.

Figure 33 illustrates the non-fuel O&M expense per retail megawatt hour.

Figure 34. **Fuel O&M Expense per Retail MWh**

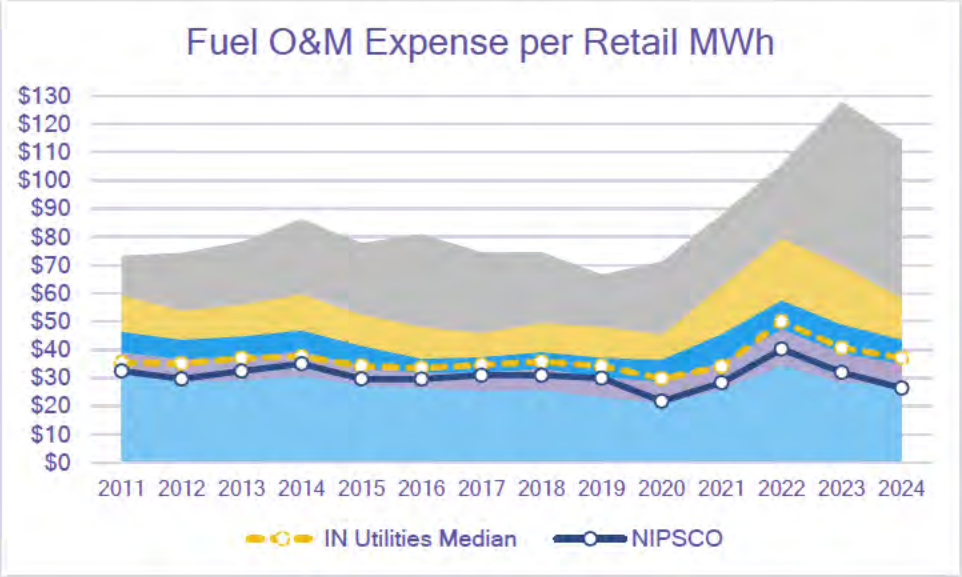


Figure 34 illustrates the fuel O&M expense per retail megawatt hour.

Figure 35. **A&G O&M Expense (net of Acct 926) per Retail MWh**

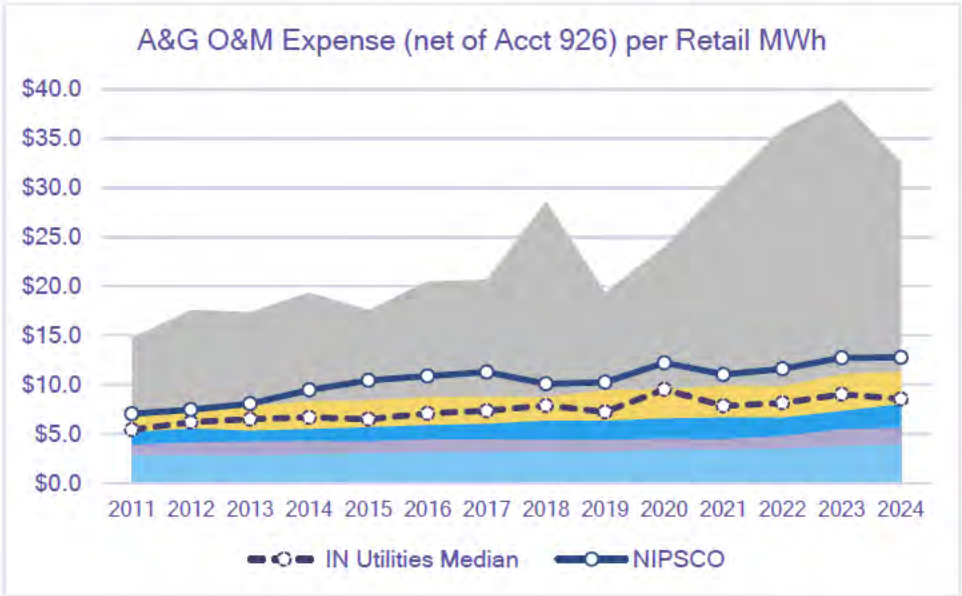


Figure 35 illustrates the A&G O&M expense (net of Acct. 926) per retail megawatt hour. The increase in 2020 was due to declining sales volumes related to COVID-19 and the implementation of Rate 831. A&G O&M expense (net of Acct. 926) per retail megawatt hour remained at the same level in 2024 compared to 2023.

AFFORDABILITY

Customer Bills

NIPSCO's most recent electric base rates went into effect on March 1, 2024.

Figure 36. **Residential Bills**[17]

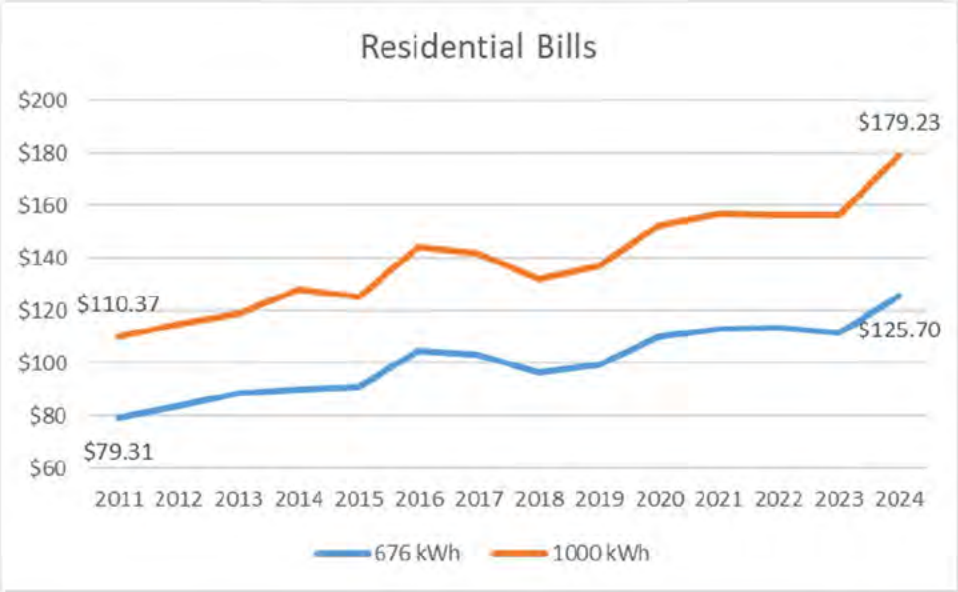


Figure 36 illustrates the average monthly bill for residential customers. NIPSCO's customers experienced a decrease in bills in 2018 primarily driven by the Tax Cuts and Jobs Act of 2017. The average monthly usage of NIPSCO's residential customers during the test year of the Company's most recent rate case, which established new rates, was 676 kWh. Residential bills experienced an increase due to a base rate case implemented March 1, 2024.

Figures 37 and 38 depict seven of the 15 demand and usage combinations that the Edison Electric Institute includes in its Typical Bills and Average Rates Report, which is published each winter.

[17] The IURC calculates each utility's electric bill on July 1 each year and reports this information at https://www.in.gov/iurc/2761.htm. For consistency, the 676 kWh number reflects July 1, 2024, data as well.

Figure 37. **Commercial Bills**

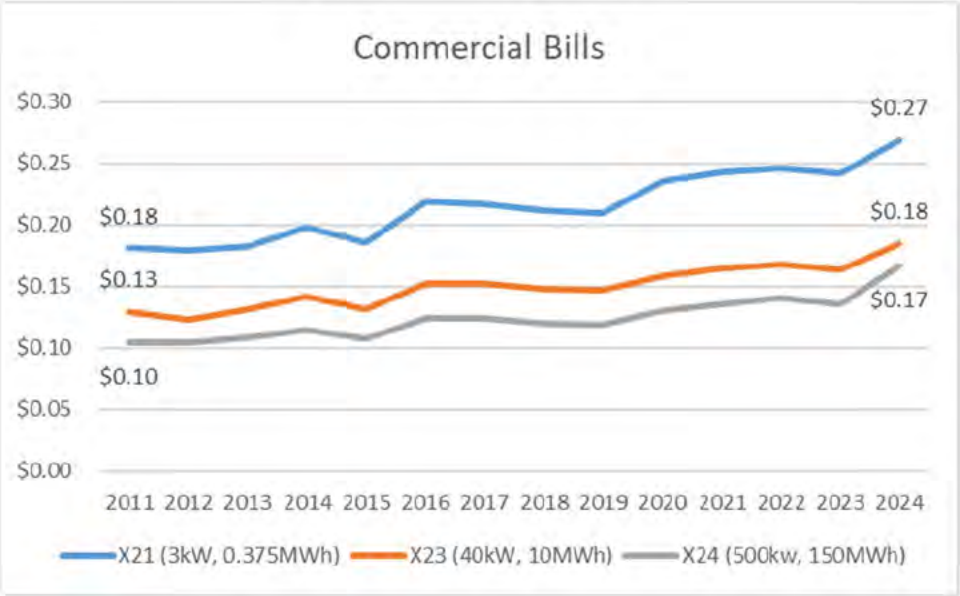


Figure 37 shows the average commercial bill per kilowatt hour. Rates increased due to a base rate case implemented March 1, 2024.

Figure 38. **Industrial Bills**[18]

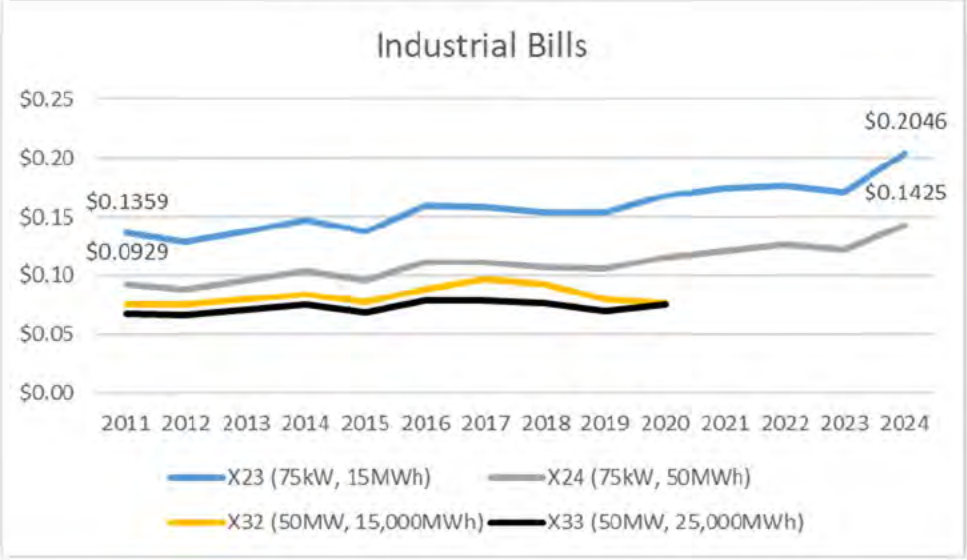


Figure 38 shows the average industrial bill per kilowatt hour. Rates increased due to a base rate case implemented March 1, 2024.

[18] Trendlines are not continued for Rate 832/833 data, due to changes to eligibility for these rates in 2020.

Figure 39. **Industrial Bills**[19]

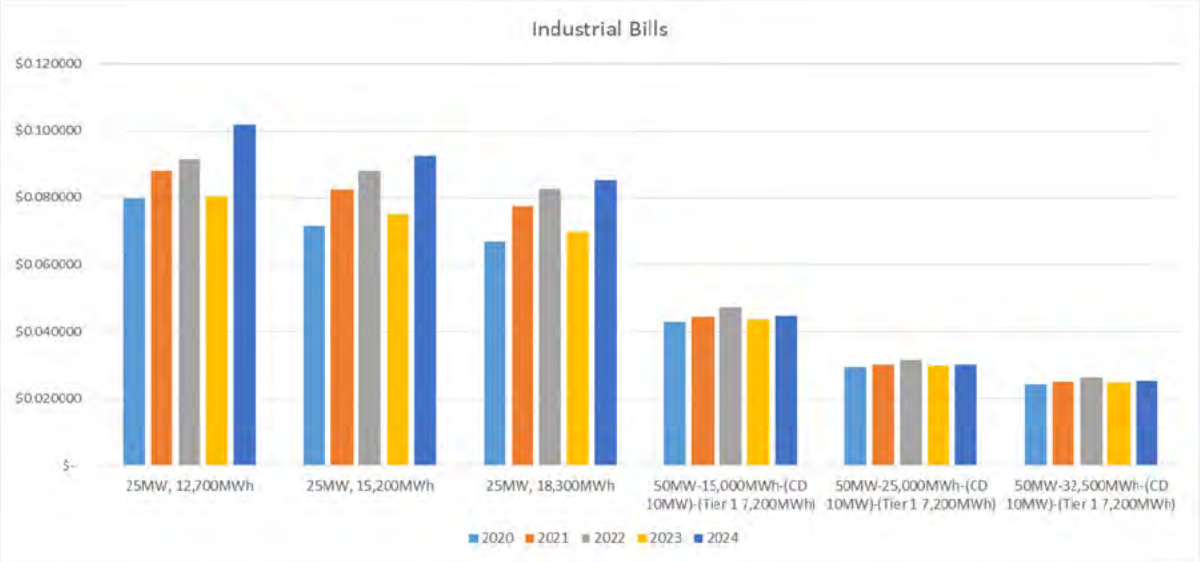


Figure 39 represents the average industrial bill for 500 Series Rates based upon the specific usage parameters. The chart is based upon the most appropriate 500 Series industrial rate for the specific usage parameters and the most appropriate rate may change over time based upon the rate design of Rates 531, 532, and 533. Rates increased due to a base rate case implemented March 1, 2024.

On January 1, 2020, NIPSCO implemented new base rates, including the introduction of a new industrial rate structure. NIPSCO's Electric Rate 531, Industrial Power Service - Large is available to Industrial Customers taking service at Transmission (> 69,000 volts) or Subtransmission voltage (34,500 volts). Customers contract for a definitive amount of electrical demand, which cannot be less than 10,000 kW. The rate also offers aggregation of premises held under common ownership and having the same qualifying service voltage.

Tier 1 is a traditional firm utility service. The default Tier 1 Contract Demand is 30,000 kW, with an option to elect above or below the default amount, down to 10,000 kW. Tier 1 includes a demand charge. Tier 1 firm energy is calculated on an hourly basis and is subject to Tier 1 energy charges, transmission charges, and applicable Riders.

[19] Rate 531 does not include Tier 2 and/or Tier 3 energy charges and costs to obtain Tier 2 and/or Tier 3 capacity.

The implementation of Rate 531 reduced NIPSCO's sales volumes, which impacts a variety of metrics. NIPSCO will continue to monitor the various metrics and is committed to working with stakeholders on the best way to illustrate Rate 531 and its influence on the various metrics.

NIPSCO regularly optimizes the customer's demand and energy based on the current rate structure. The optimal rate for 25MW demand and 12,700 MWh energy usage has historically been with the 532 rate class. However, in 2023, the optimal rate for 25MW demand and 12,700 MWh changed to rate 533. Therefore, NIPSCO has removed rate classes associated with each scenario in Figure 39 and is presenting the optimal rate based on historic actual rates with the defined scenarios.

Service Disconnections

Figure 40. **Residential Service Disconnections**

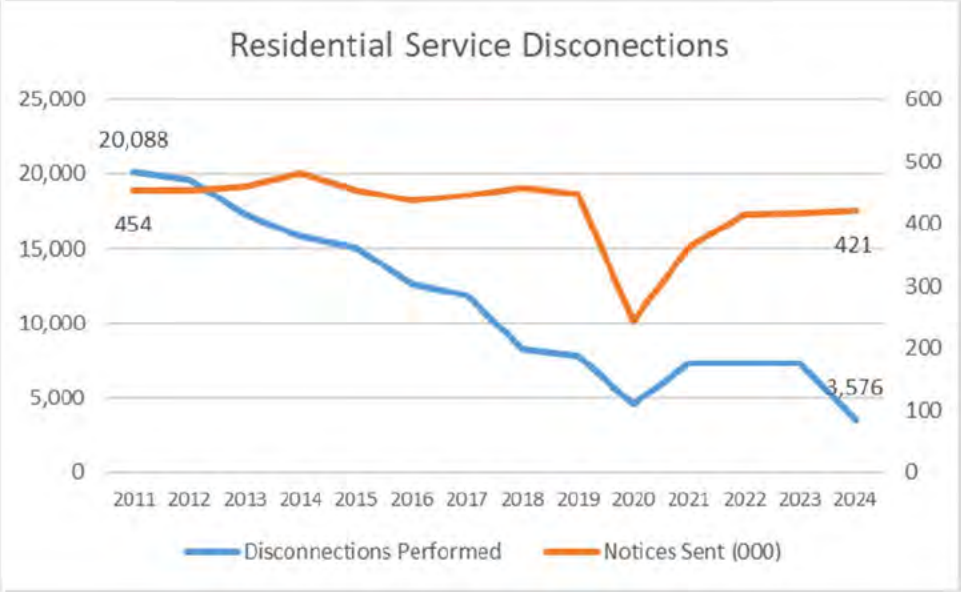


Figure 40 illustrates the number of notices sent to residential customers regarding disconnection for non-payment and the number of disconnections performed. NIPSCO sends a notice of disconnection to a customer 12 days after the customer's bill is due. NIPSCO continues to work with customers who have accounts that are in arrears, by initiating telephone calls to facilitate payment arrangements. As a result, fewer orders for disconnection are sent to the field. NIPSCO continues its program, launched in 2018, that

allows customers to make payments over the telephone, while the technician is on-site to complete the disconnection, thereby providing a final opportunity for a customer to avoid disconnection. These efforts have led to a decrease in disconnections for non-payment in recent years, compared to earlier years.

NIPSCO has continued to work with customers to make payments manageable. NIPSCO has various payment plans that range from three months up to 12 months to help customers who are struggling to stay current on their utility bills. NIPSCO has experienced an increase in customer participation in these payment plans. In 2022, NIPSCO enhanced its website functionality to allow customers to enroll in payment plans online. The Company encourages customers to sign up for budget billing, to keep payments consistent throughout the year, and promotes energy efficiency programs, to help customers reduce usage. Finally, in 2023, NIPSCO implemented a pro-active billing and payment communication program for residential customers, to assist in bill and arrears management. This proactive communication is provided via text, email, and phone calls.

Figure 41. **Average Residential Accounts in Arrears at Least 60 Days**

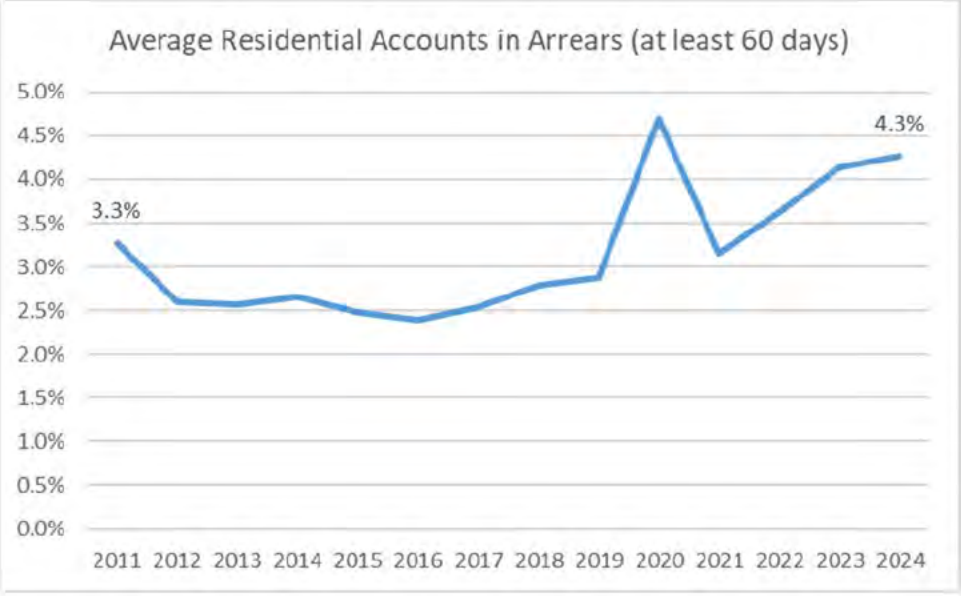


Figure 41 illustrates the average percentage of residential accounts in arrears at least 60 days. In 2024, residential accounts in arrears increased slightly compared to the previous year, due to various economic factors.

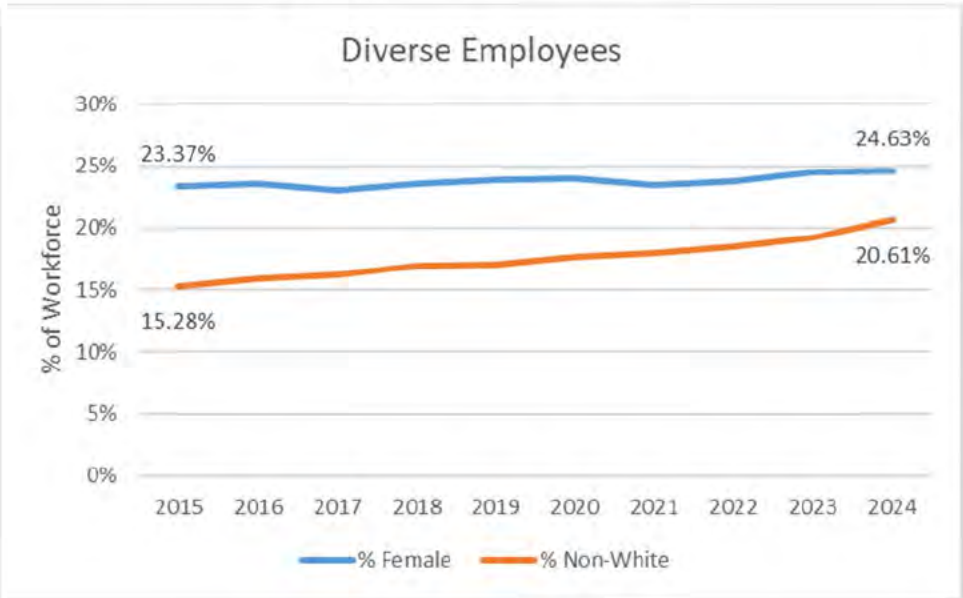
STAFFING

Figure 42. **Employee Turnover**



Figure 42 shows NIPSCO's employee turnover ratio, which is calculated using the average number of employees during the year. In 2021, NIPSCO saw a significant uptick in turnover due to voluntary departures, including retirements. The overall decrease in employee turnover at NIPSCO in 2022 and 2023 was due to a significant decline in retirements. There was a slight increase in employee turnover in 2024 due to retirements and discharges.

Figure 43. **Diverse Employees**



Since 2015, NIPSCO has been depicting data, as shown in Figure 43, concerning the diversity of its employees. In 2024, around 25% of NIPSCO's workforce comprised females, while 21% were non-white. NIPSCO maintains a dedication to fostering and preserving a diverse and capable workforce. Inclusivity and diversity extend beyond race or gender, encompassing a range of perspectives, life experiences, cultures, abilities, generations, sexual orientations, and other attributes. This commitment constitutes an ongoing, strategic endeavor integrated into the company's operational framework.

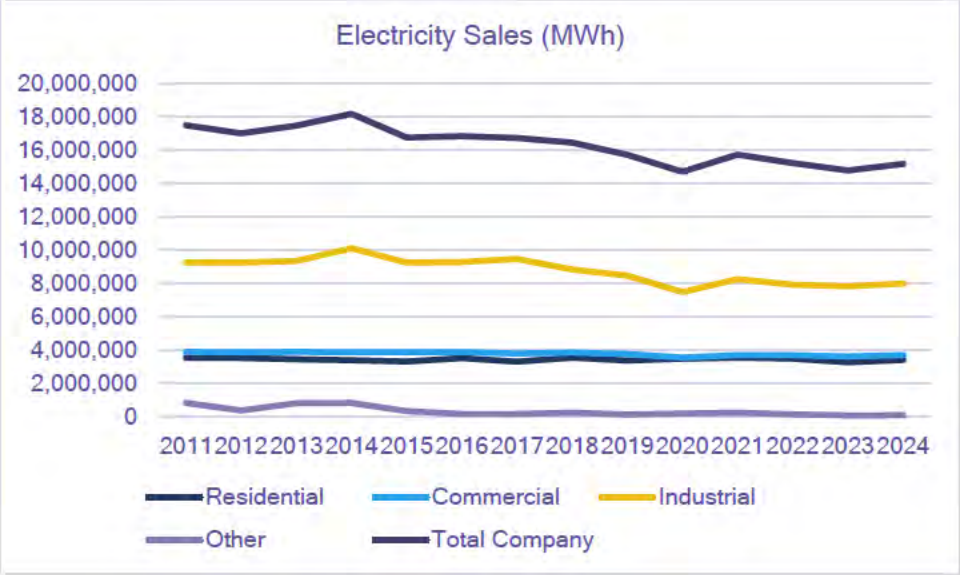
NIPSCO is committed to providing equal employment opportunities to all employees and applicants, regardless of race, color, religion, national origin or ancestry, veteran status, disability, gender, age, marital status, sexual orientation, gender identity, genetic information, or any legally protected group status. Each employee is expected to uphold this commitment and abide by these principles. Additionally, NIPSCO strives to ensure that its employees and leaders have a deep understanding of cultural issues while promoting the company’s inclusive brand within the communities it serves.

CONCLUSION

NIPSCO continues to focus on safety, reliability, customer service, investment and spending, and affordability. In 2024, NIPSCO saw improvements in several areas and laid plans for additional improvements. The common theme in all areas is NIPSCO's commitment to its customers. NIPSCO will strive to continue to improve its reliability metrics and maintain its focus on vegetation management. In addition, the Company recognizes the importance of providing excellent customer service and maintaining affordability, through rates, investments, and spending. One key to achieving all of these goals is continued employee engagement. NIPSCO appreciates the opportunity to review these metrics with its stakeholders, as it provides valuable input into the process of continued improvement.

APPENDIX

Usage Trend by Customer Class[20]



Usage by Customer Class (MWh)

Year	Residential	Commercial	Industrial	Public St & Hwy Other Auth, Rails	Interdept.	Sales for Resale	Total Company
2011	3,526,537	3,886,490	9,257,587	100,190	65,334	651,298	17,487,436
2012	3,524,316	3,863,067	9,250,975	99,172	19,924	250,843	17,008,298
2013	3,444,738	3,881,913	9,339,677	99,809	32,199	669,675	17,468,011
2014	3,384,222	3,864,241	10,114,222	103,424	44,695	675,484	18,186,288
2015	3,309,929	3,866,823	9,249,137	105,161	32,544	194,833	16,758,427
2016	3,514,821	3,878,747	9,281,765	103,797	33,066	18,998	16,831,194
2017	3,301,699	3,793,472	9,469,711	100,783	27,385	32,514	16,725,564
2018	3,535,168	3,844,574	8,829,535	96,557	27,837	114,268	16,447,940
2019	3,369,471	3,760,342	8,466,135	89,339	27,893	8,132	15,721,312
2020	3,483,963	3,550,025	7,480,320	82,070	23,928	83,548	14,703,854
2021	3,546,813	3,698,032	8,253,705	79,140	29,318	124,652	15,731,660
2022	3,482,939	3,682,376	7,915,344	69,919	19,564	49,973	15,220,115
2023	3,262,923	3,614,248	7,820,275	63,680	15,218	861	14,777,206
2024	3,404,882	3,697,947	7,984,845	70,487	14,698	-	15,172,860

[20] 'Other' category includes Interdepartment, Public Street & Highway, Other Authority, Rails, and Sales for Resale

2024 Appendix Data

	Fig.	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Safety															
Preventable vehicle crash rate	1	5.10	3.26	2.28	2.14	2.43	1.76	1.84	1.97	2.85	1.91	2.47	2.10	1.51	1.72
OSHA recordable incident rate	2	2.61	2.70	1.57	1.41	2.20	2.23	1.29	2.23	2.70	2.61	1.79	1.38	1.29	1.38
DART		1.01	1.60	1.08	0.97	1.18	1.37	0.61	1.61	1.95	1.59	1.69	0.85	0.77	0.89
OSHA rate NIPSCO w/BSA	3	2.61	1.83	1.5	1.26	1.23	1.2	0.75	1.14	1.33	1.24	1.20	0.82	0.70	0.85
DART - NIPSCO with BSA		1.1	1.04	0.93	0.84	0.65	0.61	0.33	0.68	0.88	0.75	1.04	0.54	0.44	0.58
Underground damages	4	3.48	4.50	3.73	3.11	3.00	2.56	0.258	0.209	0.22	0.121	0.182	0.082	0.099	0.043
Reliability															
Major event days	5A	7	5	6	7	3	4	2	5	8	5	10	9	6	5
Assoc. restor. days		15	12	8	11	5	6	2	7	14	8	11	15	14	6
Tree-related Outages (MED)	5B			5073	5605	4664	4275	4027	4403	4526	4488	5210	4679	3546	3853
Tree-related Outages (non-MED)				3261	3455	3925	3705	3610	3595	2933	2875	3233	2815	2624	2936
TMED (minutes)		11.8	11.5	9.4	8.2	9.5	8.7	8.2	7.9	7.8	8.5	8.6	9.3	9.3	9.3
SAIDI (MED)	6/7	371	428	524	603	248	231	153	244	359	473	529	370	320	534
(non-MED)		156	137	116	109	128	141	131	151	155	138	175	143	149	169
SAIFI (MED)	6/7	1.38	1.44	1.46	1.53	1.16	1.26	1.11	1.33	1.58	1.26	1.55	1.44	1.14	1.34
(non-MED)		1.03	0.95	0.84	0.89	0.93	1.01	1.01	1.09	1.07	0.901	1.058	0.95	0.87	0.96
CAIDI (MED)	6/7	269	297	359	395	214	184	138	184	227	374	341	257	281	399
(non-MED)		151	145	138	122	137	139	130	139	145	153	165	150	171	175
Power Generation															
Generating unit capacity	8A	**Make updates on Figure 8A tab.**													
EAF	9														
		89.88%	81.20%	64.72%	86.10%	55.36%	53.63%	45.38%	63.45%	49.30%	62.17	57.42%	48.97%	70.70%	58.37%
		70.81%	82.09%	92.36%	78.74%	70.13%	75.29%	63.93%	42.23%	Retired	Retired	Retired	Retired		
		74.38%	75.95%	84.12%	69.15%	67.23%	57.44%	66.03%	0.00%						
		69.14%	76.55%	74.21%	77.99%	69.18%	74.89%	87.62%	61.41%	51.44%	45.21	0.00%	Retired		
		75.66%	81.72%	73.63%	66.22%	87.36%	80.75%	55.15%	80.28%	62.94%	48.79	44.58%	Retired		
		91.84%	74.69%	86.52%	81.48%	74.99%	89.12%	67.84%	87.24%	79.62%	82.13	68.29%	47.26%	58.44%	71.38%
		75.99%	96.97%	94.11%	75.52%	87.18%	60.40%	92.60%	67.51%	79.45%	73.57	57.80%	59.21%	72.84%	59.15%
		79.01%	*81.22%*	*79.25%*	*76.40%*	*73.15%*	*69.91%*	*67.74%*	*66.64%*	*63.24%*	*61.06%*	*46.44%*	*51.58%*	*67.60%*	*62.60%*
		88.56%	95.27%	91.81%	93.71%	78.90%	96.28%	91.00%	73.29%	88.90%	81.38%	91.95%	89.18%	68.69%	84.83%
EFOR	10/11														
		5.14%	1.17%	6.59%	1.09%	0.47%	16.25%	6.68%	24.36%	15.05%	22.88%	16.86%	41.85%	19.27%	36.68%
		7.47%	1.88%	3.95%	3.45%	20.69%	8.32%	15.77%	56.01%	Retired	Retired	Retired	Retired		
		7.48%	7.81%	4.92%	8.78%	13.20%	22.01%	17.00%	100.00%						
		3.20%	19.26%	10.52%	19.02%	32.89%	51.25%	17.94%	20.80%	39.83%	88.14%	100.00%	Retired		
		9.61%	13.12%	1.76%	11.03%	5.62%	15.46%	17.29%	19.08%	23.28%	59.74%	40.89%	Retired		
		7.50%	7.01%	5.20%	10.29%	0.66%	6.16%	12.75%	6.15%	10.90%	8.49%	18.23%	52.53%	34.76%	24.15%
		4.11%	1.55%	0.19%	4.89%	2.69%	6.57%	2.60%	11.19%	15.21%	13.95%	39.33%	36.27%	32.33%	33.38%
		6.36%	*7.43%*	*4.46%*	*8.28%*	*7.78%*	*16.54%*	*11.14%*	*19.66%*	*21.24%*	*40.27%*	*44.02%*	*43.68%*	*28.13%*	*31.71%*
		0.96%	1.66%	1.89%	0.41%	2.43%	0.82%	1.54%	5.93%	5.33%	6.00%	4.57%	1.05%	3.72%	6.29%
Net capacity factor	12														
		72.10%	56.82%	49.25%	66.67%	40.17%	41.30%	31.41%	51.19%	26.12%	37.85%	37.17%	35.52%	35.80%	23.13%
		56.95%	44.48%	52.61%	53.50%	48.89%	53.58%	47.61%	36.58%	Retired	Retired	Retired	Retired		
		60.38%	41.73%	54.68%	50.35%	26.98%	36.44%	31.33%	0.00%						
		52.58%	27.12%	40.83%	40.20%	13.21%	12.21%	17.00%	38.98%	32.20%	4.65%	-0.039%	Retired		
		59.41%	55.92%	54.02%	47.28%	45.04%	24.13%	20.25%	51.59%	37.62%	18.16%	34.67%	Retired		
		47.18%	30.42%	41.62%	65.64%	38.81%	49.30%	39.76%	55.00%	39.79%	29.61%	38.88%	32.65%	26.52%	28.05%
		52.06%	51.13%	71.35%	63.88%	56.69%	44.11%	70.27%	44.64%	46.06%	26.07%	36.12%	34.88%	22.43%	25.49%
		57.80%	*44.54%*	*51.63%*	*55.30%*	*37.64%*	*35.02%*	*34.62%*	*45.05%*	*35.76%*	*23.03%*	*29.36%*	*34.45%*	*28.85%*	*25.36%*
		46.64%	64.18%	50.98%	45.81%	68.41%	78.33%	73.79%	61.15%	75.91%	68.75%	59.14%	69.41%	60.62%	83.00%
	13										40.95%	35.50%	37.52%	32.20%	35.20%
												25.25%	31.82%	30.80%	34.90%
	14													17.80%	22.40%
														18.20%	21.20%
															22.27%
Gross Energy Availablity (GEA)															
	15										87.00%	94.59%	92.47%	88.80%	93.80%
												74.80%	83.78%	91.30%	96.10%
														86.70%	N/A
														85.20%	N/A
Solar Net Performance Ratio (NPR)	16														
														91.00%	84.00%
														84.80%	80.80%
															82.79%
Technical Energy Availability (TEA)															
	17										87.00%	95.64%	96.21%	91.10%	96.60%
												95.50%	92.01%	97.90%	98.50%
														89.10%	N/A
														87.50%	N/A
Distributed Generation															
Customer Satisfaction															
Avg speed of answer (sec)	20	51	20	21	29	18	21	28	27	45	68	90	239	182	100
Abandonment rate		2.8%	1.3%	1.5%	1.6%	1.4%	1.6%	2.3%	2.2%	2.9%	6.5%	5.3%	17.2%	11.6%	7.5%
First call resolution	21	74%	79%	75%	77%	77%	80%	87%	87%	87%	86%	86%	83%	83%	89%
Meter reading		91%	94%	92%	92%	99%	100%	100%	100%	100%	100%	100%	100%	100%	99%
Customer survey	22	88%	86%	83%	84%	87%	88%	88%	90%	89%	88%	88%	84%	84%	83%
J.D. Power scores	23														
		585	604	624	618	648	645	704	706	714	743	752	724	705	700
		640	645	616	653	612	671	735	760	771	722	753	713	753	804
Complaints to regulator	24														
		2	2	1	0	1	2	1	0	0	1	0	1	1	2
		84	62	66	73	78	64	61	77	98	38	24	60	46	49
		82	60	65	73	77	62	60	77	98	37	24	59	45	47

	Fig.	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
O&M Expenses															
O&M per MWh (total)		$56.57	$57.19	$59.70	$62.67	$59.79	$62.21	$65.59	$61.00	$61.89	$55.35	$58.31	$70.63	$64.79	$57.06
(non-fuel)		$24.09	$27.52	$27.26	$27.63	$30.14	$32.59	$34.59	$30.04	$31.93	$33.56	$29.97	$30.35	$32.81	$30.64
O&M per customer (total)		$2,084	$2,095	$2,186	$2,386	$2,146	$2,254	$2,346	$2,120	$2,055	$1,695	$1,891	$2,211	$1,966	$1,764.55
(non-fuel)		$888	$1,008	$998	$1,052	$1,082	$1,181	$1,237	$1,044	$1,060	$1,028	$972	$950	$995	$947.47
Non-fuel production O&M															
		$9.27	$10.73	$9.63	$9.85	$11.02	$12.74	$14.17	$11.06	$10.73	$10.42	$9.14	$7.82	$7.71	$4.97
		$10.53	$13.74	$11.86	$12.11	$15.13	$17.71	$19.72	$15.11	$16.35	$20.14	$17.78	$17.02	$19.06	$11.16
Transmission per MWh		$1.15	$1.31	$1.69	$1.73	$2.14	$2.63	$2.76	$2.73	$3.17	$3.36	$3.38	$3.63	$3.68	$3.93
Transmission per pole mile		$7,161	$7,985	$26,699	$28,367	$32,333	$39,913	$41,638	$36,477	$40,575	$36,159	$43,193	$44,913	$44,170	$48,510.57
Distribution expense per MWh		$2.51	$2.80	$2.76	$2.40	$2.47	$2.60	$2.97	$3.37	$3.74	$4.32	$3.99	$4.30	$4.41	$4.88
Customer operations per MWh		$1.07	$1.25	$1.29	$1.20	$1.22	$1.13	$1.05	$1.08	$1.18	$1.05	$1.09	$1.25	$1.23	$1.25
A&G per MWh		$9.20	$10.44	$10.50	$11.15	$12.63	$13.13	$13.24	$11.24	$12.72	$13.86	$11.78	$12.90	$15.45	$15.23
		$6.79	$7.36	$7.76	$9.12	$10.32	$10.86	$11.26	$10.01	$10.24	$12.15	$10.95	$11.57	$12.73	$12.76
A&G per customer		$352	$388	$400	$441	$459	$476	$474	$393	$423	$427	$385	$405	$469	$471.07
		$260	$274	$296	$361	$375	$394	$403	$351	$340	$374	$358	$364	$386	$394.66
Benchmarking															
O&M expense per retail MWh															
		$53	$51	$52	$54	$52	$48	$49	$49	$48	$46	$52	$60	$55	$ 55.98
		$65	$62	$64	$67	$62	$61	$61	$63	$62	$58	$63	$75	$72	$ 69.78
		$77	$73	$75	$79	$72	$69	$69	$71	$70	$70	$80	$92	$86	$ 85.50
		$88	$86	$88	$94	$87	$81	$84	$86	$86	$86	$100	$113	$111	$ 105.50
		$58	$62	$63	$66	$60	$62	$66	$67	$68	$63	$66	$94	$73	$ 73.00
		$57	$57	$60	$63	$60	$62	$66	$61	$62	$55	$58	$71	$65	$ 57.06
O&M (non fuel) per retail MWh															
		$17	$18	$18	$20	$20	$20	$20	$20	$21	$21	$19	$22	$24	$ 25.45
		$23	$23	$24	$25	$26	$26	$27	$27	$27	$28	$26	$27	$31	$ 32.14
		$28	$29	$30	$31	$32	$32	$33	$32	$34	$34	$34	$35	$39	$ 39.70
		$39	$40	$40	$43	$42	$43	$42	$44	$44	$44	$46	$47	$49	$ 51.40
		$24	$28	$27	$28	$28	$30	$33	$32	$34	$34	$34	$37	$40	$ 32.07
		$24	$28	$27	$28	$30	$33	$35	$30	$32	$34	$30	$30	$33	$ 30.64
A&G (less Acct 926) per MWh															
		$2.81	$2.86	$2.77	$2.94	$3.04	$3.16	$3.16	$3.21	$3.15	$3.43	$3.38	$3.48	$3.77	$3.92
		$3.89	$4.14	$4.22	$4.27	$4.22	$4.47	$4.43	$4.39	$4.39	$4.50	$4.46	$4.79	$5.48	$5.63
		$5.20	$5.53	$5.32	$5.48	$5.69	$5.88	$6.03	$6.34	$6.33	$6.57	$6.67	$6.65	$7.32	$8.03
		$7.34	$7.50	$7.83	$8.31	$8.39	$8.74	$8.78	$8.74	$9.44	$9.53	$9.92	$9.84	$11.05	$11.33
		$5.42	$6.20	$6.50	$6.68	$6.50	$7.09	$7.34	$7.88	$7.23	$9.51	$7.84	$8.15	$9.03	$8.55
		$7.05	$7.47	$8.07	$9.47	$10.44	$10.88	$11.28	$10.08	$10.25	$12.22	$11.04	$11.61	$12.73	$12.76

	Fig.	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Affordability															
Residential rates (as of July 1)	36														
Bill (698kWh)		$79	$84	$89	$90	$91	$105	$103	$97	$99	$110	$113	$113	$112	$126
Bill (1000kWh)		$110	$115	$119	$128	$125	$144	$142	$132	$137	$152	$157	$157	$156	$179
Components ($/kWh, May 1 of *following* year, as of July 1 for 2021)															
base fuel								$0.0325	$0.0325	$0.0325	$0.0267	$0.0267	$0.0267	$0.0267	N/A
O&M expense								$0.0294	$0.0294	$0.0294	$0.0406	$0.0406	$0.0406	$0.0406	N/A
D&A expense								$0.0133	$0.0133	$0.0133	$0.0259	$0.0259	$0.0259	$0.0259	N/A
taxes								$0.0100	$0.0073	$0.0073	$0.0072	$0.0072	$0.0072	$0.0072	N/A
NOI and settlement adjust't								$0.0130	$0.0130	$0.0130	$0.0220	$0.0220	$0.0220	$0.0220	N/A
capital trackers								$0.0016	$0.0038	$0.0039	$0.0028	$0.0013	$0.0032	$0.0014	N/A
expense trackers								$0.0138	$0.0126	$0.0077	$0.0121	$0.0184	$0.0170	-$0.0001	N/A
total								$0.1136	$0.1119	$0.1071	$0.1373	$0.1421	$0.1426	$0.1236	N/A
Variable charges (cents) (as of July 1 for 2023)															
811 energy							11.0433	11.0433	10.6764	10.6764	0.1241	0.124141	0.124141	0.122108	N/A
870 FAC							0.2625	0.0836	-0.3279	-0.1999	-0.0011	0.0031	0.0098	0.0045	N/A
871 RTO							0.1664	0.1220	0.2138	0.1015	0.0026	0.003767	0.002835	0.002357	N/A
872 ECR							0.9330	0.4221	0.2963	0.2745	0	0	0	0	N/A
874 RA							0.3030	0.4388	0.4160	0.3651	0.0041	-0.00031	0.000136	0.000644	N/A
883 DSM							0.3157	0.3770	0.2272	0.5053	0.0056	0.006331	0.0052951	0.003612	N/A
887 FMC							-0.0011	-0.0019	0.0249	0.1325	0.0003	0.0000	0.0000	0.0000	N/A
888 TDSIC							0.0000	0.3204	0.3159	0.3813	0.0011	0.003722	0.002997	0.007746	N/A
Total variable charge							13.0228	12.8053	11.8426	12.2367	0.1368	0.1368	0.1368	0.1409	N/A
Customer charge ($)						$11.00	$14.00	$14.00	$14.00	$14.00	$13.50	$13.50	$13.50	$13.50	N/A
Commercial rates															
Rate 721 3 kW .375 MWh 17%		$0.181	$0.180	$0.183	$0.198	$0.186	$0.218	$0.217	$0.212	$0.210	$0.236	$0.242	$0.245	$0.242	$0.269
Rate 721 12 kW 1.5 MWh 17%		$0.141	$0.140	$0.143	$0.158	$0.146	$0.170	$0.169	$0.164	$0.162	$0.175	$0.182	$0.185	$0.181	$0.203
Rate 723 40 kW 10 MWh 34%		$0.130	$0.123	$0.131	$0.142	$0.132	$0.153	$0.152	$0.148	$0.147	$0.158	$0.164	$0.167	$0.164	$0.184
Rate 723 40 kW 14 MWh 48%		$0.115	$0.108	$0.116	$0.127	$0.117	$0.137	$0.136	$0.131	$0.131	$0.144	$0.151	$0.153	$0.148	$0.173
Rate 723 500 kW 150 MWh 41%		$0.104	$0.104	$0.108	$0.115	$0.107	$0.124	$0.124	$0.120	$0.119	$0.130	$0.135	$0.141	$0.136	$0.167
Rate 724 500 kW 180 MWh 49%		$0.097	$0.097	$0.101	$0.108	$0.100	$0.117	$0.116	$0.113	$0.111	$0.122	$0.127	$0.133	$0.128	$0.156
Industrial rates															
Rate 723 75 kW 15 MWh 27%	38	$0.136	$0.129	$0.137	$0.147	$0.137	$0.159	$0.159	$0.154	$0.154	$0.168	$0.175	$0.177	$0.172	$0.205
Rate 723 75 kW 30 MWh 55%		$0.107	$0.100	$0.108	$0.118	$0.108	$0.128	$0.127	$0.123	$0.122	$0.135	$0.141	$0.144	$0.139	$0.160
Rate 724 75 kW 50 MWh 91%	38	$0.093	$0.088	$0.096	$0.104	$0.096	$0.111	$0.111	$0.107	$0.106	$0.116	$0.122	$0.127	$0.123	$0.143
Rate 724 1,000 kW 200 MWh 27%		$0.120	$0.120	$0.125	$0.132	$0.124	$0.142	$0.142	$0.138	$0.137	$0.149	$0.154	$0.159	$0.155	$0.193
Rate 724 1,000 kW 400 MWh 55%		$0.091	$0.091	$0.095	$0.102	$0.094	$0.111	$0.110	$0.107	$0.105	$0.116	$0.121	$0.126	$0.122	$0.148
Rate 724 1,000 kW 650 MWh 89%		$0.080	$0.080	$0.084	$0.091	$0.083	$0.099	$0.098	$0.095	$0.093	$0.103	$0.108	$0.114	$0.110	$0.130
Rate 732 50,000 kW 15,000 MWh 69%	38	$0.075	$0.076	$0.080	$0.084	$0.078	$0.088	$0.097	$0.093	$0.079	$0.076	$0.088	$0.091	$0.091	$0.126
Rate 73350,000 kW 25,000 MWh 83%	38	$0.068	$0.067	$0.071	$0.075	$0.069	$0.079	$0.079	$0.076	$0.070	$0.075	$0.082	$0.088	$0.075	$0.092
Rate 733 50,000 kW 32,500 MWh 100%		$0.057	$0.065	$0.066	$0.071	$0.065	$0.072	$0.071	$0.068	$0.066	$0.067	$0.077	$0.083	$0.070	$0.085
Residential disconnections															
Non-Payment	40	20,088	19,585	17,271	15,824	15,011	12,689	11,900	8,232	7,854	4,537	7,361	7,314	7,319	3,576
Notices Sent (000)	40	454	454	460	480	455	438	446	458	448	244	363	415	416	421
Disconnections by Month															
Jan		1,408	1,875	1,466	354	863	835	1,304	22	483	837	454	273	575	142
Feb		866	1,560	1,284	219	323	912	1,456	415	881	600	293	282	700	196
Mar		2,018	1,806	1,418	1,084	1,411	1,068	1,132	928	776	468	664	713	829	365
Apr		1,751	1,655	1,892	1,653	1,635	953	817	861	786	0	780	731	705	592
May		1,748	1,571	1,580	1,665	1,318	740	1,150	1,253	628	0	645	862	783	543
Jun		1,711	1,339	1,145	1,635	1,393	872	962	997	726	1	642	746	720	308
Jul		1,482	1,029	1,323	1,353	907	885	854	801	628	0	537	748	423	123
Aug		1,914	1,644	1,196	1,437	1,262	1,185	1,323	808	684	12	629	586	574	164
Sep		1,607	1,471	1,061	1,425	908	951	745	406	691	879	839	676	521	299
Oct		1,436	1,553	1,365	1,341	1,158	939	1,026	619	677	668	620	650	523	331
Nov		1,211	1,107	796	452	999	930	804	533	456	611	585	575	477	347
Dec		925	963	732	1,192	819	403	327	589	438	461	673	472	489	166
Accounts in Arrears															
Jan		4.0%	3.0%	2.7%	2.8%	2.8%	2.9%	2.6%	3.5%	2.8%	2.5%	4.8%	3.8%	3.9%	4.4%
Feb		4.2%	2.8%		2.8%	2.9%	2.4%	2.4%	3.5%	2.8%	2.6%	4.5%	4.1%	3.8%	4.0%
Mar		4.1%	2.6%	2.4%	2.5%	2.5%	2.0%	2.2%	3.2%	2.5%	2.7%	3.8%	3.5%	3.6%	4.0%
Apr		3.6%	2.5%	2.1%	2.5%	2.3%	2.3%	2.5%	2.7%	2.6%	4.1%	3.0%	3.8%	4.3%	4.1%
May		3.7%	2.7%	2.2%	2.7%	2.6%	2.3%	2.4%	2.3%	2.7%	5.7%	2.9%	3.9%	4.4%	3.8%
Jun		3.0%	2.8%	2.7%	2.8%	2.4%	2.2%	2.4%	2.5%	3.1%	6.0%	2.8%	3.5%	4.3%	4.2%
Jul		3.1%	2.3%	2.4%	2.6%	2.4%	2.4%	2.6%	2.4%	3.0%	6.5%	2.6%	3.6%	4.4%	4.1%
Aug		2.7%	2.1%	2.3%	2.4%	2.1%	2.0%	2.0%	2.3%	2.3%	5.8%	2.5%	3.3%	4.0%	4.0%
Sep		2.0%	2.2%	2.3%	2.2%	2.1%	1.9%	2.5%	2.5%	2.5%	5.6%	2.4%	3.2%	3.9%	4.1%
Oct		2.5%	2.6%	2.5%	2.3%	2.3%	2.4%	2.6%	2.6%	3.0%	5.4%	2.6%	3.4%	4.0%	4.4%
Nov		3.0%	2.7%	3.0%	3.1%	2.5%	2.7%	2.8%	2.8%	3.5%	4.9%	2.8%	3.3%	4.3%	4.9%
Dec		3.3%	3.1%	3.6%	3.3%	2.9%	3.2%	3.6%	3.2%	3.6%	5.1%	3.1%	4.0%	4.8%	5.4%
Average	41	3.3%	2.6%	2.6%	2.7%	2.5%	2.4%	2.5%	2.8%	2.9%	4.7%	3.2%	3.6%	4.1%	4.3%
Staffing															
Employee turnover	42	6.7%	5.1%	6.8%	5.6%	6.2%	5.9%	6.3%	7.3%	6.7%	5.8%	8.2%	6.3%	5.8%	6.1%
% Female	43					23.37%	23.59%	23.08%	23.55%	23.88%	24.01%	23.50%	23.78%	24.52%	24.63%
% Non-White	43					15.28%	15.86%	16.21%	16.90%	17.06%	17.63%	18.01%	18.52%	19.21%	20.61%
Ratio data															
Energy (MWh, millions)															
		15.39	13.28	14.18	14.79	12.20	12.11	12.02	12.04	10.32	7.61	8.10	6.99	5.98	$7
		16.84	16.76	16.80	17.51	16.56	16.81	16.69	16.33	15.71	14.62	15.61	15.17	14.78	$15
		0.65	0.25	0.67	0.68	0.19	0.02	0.03	0.11	0.010	0.08	0.12	0.05	0	$0
O&M ($, millions)															
		$952	$958	$1,003	$1,097	$990	$1,046	$1,095	$996	$972	$809	$910	$1,072	$957	$866
		$162	$182	$168	$179	$185	$214	$237	$182	$169	$153	$144	$119	$114	$75
		$547	$497	$545	$614	$491	$498	$517	$506	$471	$319	$442	$611	$473	$401
		$0	$10	$6	$5	$5	$5	$6	$6	$6	$5	$6	$5	$5	$6
		$20	$22	$29	$31	$36	$44	$46	$45	$50	$49	$53	$55	$54	$60
		$44	$48	$48	$44	$41	$44	$50	$55	$58	$63	$63	$65	$65	$74
		$19	$21	$23	$22	$20	$19	$18	$18	$19	$16	$17	$19	$18	$19
		$161	$178	$183	$203	$212	$221	$221	$185	$200	$204	$185	$196	$228	$231

MED - See MED Appendix Data
EDG - See EDG Table

MED Appendix Data

Date	SAIDI	SAIFI	Date	SAIDI	SAIFI	Date	SAIDI	SAIFI	Date	SAIDI	SAIFI	Date	SAIDI	SAIFI	Date	SAIDI	SAIFI	Date	SAIDI	SAIFI	Date	SAIDI	SAIFI
5/29/2011	17.72	0.0434	6/29/20112	53.75	0.078	3/12/2014	30.9	0.1174	2/19/2016	9.83	0.0499	2/12/2019	17.59	0.0553	6/9/2020	12.371	0.0428	4/14/2022	11.022	0.0459	2/22/2023	24.354	0.0269
5/30/2011	2.83	0.0115	6/30/2012	7.13	0.0191	3/13/2014	0.09	0.0007	2/20/2016	0.28	0.0017	2/13/2019	0.18	0.0014	6/10/2020	31.083	0.0483	4/15/2022	1.594	0.0115	2/23/2023	1.822	0.0040
5/31/2011	0.27	0.035	7/1/2012	7.34	0.0279	5/11/2014	31.01	0.0628	2/21/2016	0.02	0.0002	5/23/2019	41.01	0.0891	6/11/2020	0.947	0.0022	6/13/2022	54.342	0.0648	2/24/2023	0.089	0.0003
6/4/2011	98.8	0.0976	7/2/2012	0.3	0.0034	5/12/2014	6.78	0.0114	2/24/2016	56.4	0.105	5/24/2019	0.78	0.0048	6/12/2020	0.365	0.0029	6/14/2022	12.326	0.0212	3/3/2023	13.850	0.0402
6/5/2011	19.47	0.0137	7/5/2012	22.23	0.0548	5/13/2014	0.73	0.0039	2/25/2016	3.65	0.0104	5/25/2019	0.1	0.0005	6/26/2020	17.243	0.0418	6/15/2022	0.862	0.0035	3/4/2023	1.071	0.0024
6/6/2011	4.46	0.0097	7/6/2012	1.9	0.0057	5/14/2014	0.1	0.001	2/26/2016	0.15	0.0011	6/26/2019	7.88	0.0297	6/27/2020	1.442	0.0049	6/16/2022	0.928	0.0078	3/5/2023	0.055	0.0008
6/7/2011	1.15	0.005	7/7/2012	0.29	0.0048	6/30/2014	202.78	0.2132	7/21/2016	9.25	0.0448	6/27/2019	3.42	0.0167	6/28/2020	0.311	0.0017	7/5/2022	10.28	0.047	3/31/2023	37.406	0.0500
6/8/2011	0.62	0.0052	7/18/2012	20.08	0.0535	7/1/2014	168.11	0.1271	7/22/2016	0.68	0.0031	6/28/2019	0.29	0.0027	8/10/2020	242.893	0.2105	7/6/2022	1.66	0.0068	4/1/2023	3.805	0.0081
6/9/2011	2.4	0.0167	7/19/2012	6.39	0.0281	7/2/2014	9.63	0.0098	12/4/2016	15.37	0.0479	8/18/2019	25.03	0.0594	8/11/2020	31.157	0.0194	7/23/2022	45.264	0.097	4/2/2023	1.820	0.0081
7/1/2011	13.55	0.0446	7/20/2012	0.1	0.0007	7/3/2014	3.69	0.0121	12/5/2016	1.11	0.0093	8/19/2019	0.5	0.0026	8/12/2020	5.813	0.0045	7/24/2022	1.592	0.0067	4/3/2023	0.130	0.0008
7/2/2011	2.83	0.0134	7/24/2012	100.66	0.167	7/4/2014	0.87	0.005	1/10/2017	13.44	0.0584	8/20/2019	0.22	0.0013	8/13/2020	1.175	0.0013	7/25/2022	0.415	0.003	4/4/2023	2.488	0.0191
7/3/2011	0.16	0.0011	7/25/2012	3.13	0.0074	7/5/2014	0.15	0.0006	1/11/2017	0.81	0.0042	9/3/2019	9.07	0.036	8/14/2020	1.343	0.006	8/3/2022	26.364	0.0565	4/5/2023	1.789	0.0130
7/11/2011	17.71	0.0537	7/26/2012	1.49	0.0064	9/20/2014	11.17	0.0318	3/8/2017	8.78	0.0452	9/4/2019	0.06	0.0005	8/15/2020	0.611	0.0028	8/4/2022	1.766	0.0088	7/5/2023	10.597	0.0291
7/12/2011	0.42	0.0034	8/4/2012	93.59	0.14	9/21/2014	1.84	0.0089	3/9/2017	0.05	0.0003	9/27/2019	25.46	0.0676	1/1/2021	130.273	0.1198	8/5/2022	0.204	0.0012	7/6/2023	1.049	0.0056
7/13/2011	0.42	0.007	8/5/2012	6.67	0.0135	9/22/2014	0.21	0.001	7/4/2018	16.1	0.042	9/28/2019	1.3	0.0037	1/2/2021	20.26	0.0156	8/29/2022	32.676	0.0758	7/7/2023	0.107	0.0007
7/22/2011	24.27	0.0545	8/6/2012	0.25	0.0018	10/31/2014	40.66	0.0742	7/5/2018	8.37	0.0278	9/29/2019	0.74	0.004	1/3/2021	11.454	0.0193	8/30/2022	2.223	0.0075	7/28/2023	59.445	0.0825
7/23/2011	4.56	0.0129	8/7/2012	0.13	0.0007	11/1/2014	0.72	0.0017	7/6/2018	0.39	0.0019	10/21/2019	66.08	0.1229	1/4/2021	0.503	0.0025	8/31/2022	0.227	0.0017	7/29/2023	26.657	0.0403
7/24/2011	1.78	0.0091	6/12/2013	40.36	0.0965	11/2/2014	0.14	0.0009	7/7/2018	0.08	0.0007	10/22/2019	3.18	0.0063	1/5/2021	0.074	0.0005	10/17/2022	17.164	0.0279	7/30/2023	0.868	0.0026
7/25/2011	0.27	0.0033	6/13/2013	5.55	0.0126	2/1/2015	15.65	0.0543	7/8/2018	0.45	0.0024	10/23/2019	0.38	0.0036	6/20/2021	24.499	0.0369	10/18/2022	1.168	0.0049	7/31/2023	0.161	0.0007
#########	24.1	0.0438	6/14/2013	0.18	0.0011	2/2/2015	0.24	0.0012	9/25/2018	14.2	0.0447	10/24/2019	0.19	0.0012	6/21/2021	58.089	0.104	10/19/2022	0.976	0.005	7/15/2024	293.924	0.2447
#########	7.41	0.0104	6/24/2013	176.66	0.216	7/18/2015	18.4	0.0046	9/26/2018	1.19	0.0065	11/27/2019	12.52	0.053	6/22/2021	0.486	0.004	11/5/2022	17.284	0.05	7/16/2024	34.406	0.0381
12/1/2011	0.12	0.0006	6/25/2013	38.61	0.0457	7/19/2015	0.74	0.0027	10/20/2018	12.76	0.0377	11/28/2019	0.21	0.0021	6/23/2021	0.188	0.0012	11/6/2022	0.57	0.0027	7/17/2024	10.232	0.0105
			6/26/2013	12.42	0.0119	12/28/2015	85.89	0.1257	10/21/2018	0.13	0.0009				6/26/2021	11.217	0.0255	11/7/2022	0.239	0.0021	7/18/2024	0.562	0.0014
			6/27/2013	51.3	0.0736	12/29/2015	3.88	0.0061	11/26/2018	41.65	0.0892				6/27/2021	0.811	0.0027	11/8/2022	0.107	0.0012	7/19/2024	0.272	0.0010
			6/28/2013	7.75	0.0257	12/30/2015	0.97	0.0049	11/27/2018	0.13	0.0004				6/28/2021	2.462	0.0141				7/20/2024	0.085	0.0006
			6/29/2013	0.99	0.0061	12/31/2015	0.05	0.0002	11/28/2018	0.06	0.0006				8/11/2021	48.251	0.0601				8/27/2024	13.262	0.0246
			11/17/2013	88.4	0.1684										8/12/2021	26.482	0.041				8/28/2024	2.093	0.0098
			11/18/2013	5.06	0.0086										8/13/2021	0.608	0.002				8/29/2024	0.048	0.0004
			11/19/2013	0.87	0.0054										8/14/2021	0.282	0.0022				12/4/2024	13.831	0.0545
			11/20/2013	0.16	0.0012										8/25/2021	9.542	0.0269				12/5/2024	0.543	0.0073
			11/21/2013	0.29	0.0024										8/26/2021	1.13	0.0055						
															12/11/2021	14.742	0.0447						
															12/12/2021	0.101	0.0008						
															12/13/2021	0.084	0.0006						

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. 202-26-46
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	)))))	Order No. 202-26-47

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

Exhibit 14
Saffran Q1 2025 Outage Testimony

FILED
May 23, 2025
INDIANA UTILITY
REGULATORY COMMISSION

VERIFIED DIRECT TESTIMONY OF DAVID SAFFRAN

Q1. Please state your name, title, and business address.

A1. My name is David Saffran. My title is Generation Business Systems Administrator in the Operations Management Reporting division of Northern Indiana Public Service Company LLC ("NIPSCO" or the "Company"). My business address is 2755 Raystone Drive, Valparaiso, Indiana 46383.

Q2. Please describe your educational and employment background.

A2. I hold an Associate degree in Electronic Systems Technology from the Community College of the Air Force, an Associate degree in Aerospace Ground Equipment Technology from the Community College of the Air Force and have attended classes for three years working towards a Bachelor of Science degree in Computer Networking Information Technology at Purdue Northwest. I have been employed by NiSource Inc. or NIPSCO since May of 2004 in a variety of technical, supervisory, and administrative positions.

Q3. What are your responsibilities as Generation Business Systems

Administrator in the Operations Management Reporting division of NIPSCO?

A3. My current responsibilities include managing NIPSCO's various business systems and programs, recording data concerning Generation's operational and maintenance performance, and analyzing the results to identify adverse trends and recommend corrective actions to improve performance. In addition, I am responsible for submitting various NIPSCO Generation reports and filings to local, state, and federal agencies such as the Indiana Utility Regulatory Commission ("Commission"), Midcontinent Independent System Operator, Inc., North American Electric Reliability Council, Federal Energy Regulatory Commission ("FERC") and Indiana Department of Natural Resources ("DNR").

Q4. Are you familiar with the Company's Verified Petition, including the exhibits attached thereto, initiating this proceeding, a copy of which has been marked <u>Attachment 1-A</u>?

A4. Yes.

Q5. What is the purpose of your direct testimony in this proceeding?

A5. The purpose of my testimony is to provide information relevant to Paragraph 6 of Exhibit A - Settlement Terms, attached to the Stipulation and Agreement filed October 16, 2007 in Cause No. 38706-FAC71-S1 approved by the Commission on January 30, 2008 ("FAC71-S1 Agreement") and Paragraph 6(f.) of the Stipulation and Agreement filed September 23, 2009 in Cause No. 38706-FAC80-S1 approved by the Commission on November 4, 2009 ("FAC80-S1 Agreement") (collectively, the "Reporting Agreements"). Paragraph 6 of the FAC71-S1 Agreement calls for NIPSCO to submit testimony in its quarterly FAC proceedings regarding major forced outages that occur within the pertinent FAC timeframe. Under this provision, NIPSCO must describe the length and cause of each major forced outage, generating unit involved, and proposed solutions to prevent such outages from occurring in the future. In addition to the above provision regarding the details of each major forced outage, Paragraph 6(f.) of the FAC80-S1 Agreement calls for NIPSCO to file testimony describing the details of and the steps taken to minimize such major forced outages in the future. Paragraph 6(f.) of the FAC80-S1 Agreement defines a "major forced outage" as a unit forced outage lasting longer than three (3) consecutive days.

Q6. Are you sponsoring any attachments to your testimony?

A6. Yes. I am sponsoring Attachment 4-A and Confidential Attachment 4-B, both of which were prepared by me or under my direction and supervision. Attachment 4-A describes each major forced outage NIPSCO's generating units experienced during the first quarter of 2025, which is the reconciliation period in this FAC proceeding. Confidential Attachment 4-B contains root-cause analysis reports regarding the outages listed in Attachment 4-A that were complete at the time of this filing.

Q7. Does Attachment 4-A comply with the Reporting Agreements?

A7. Yes. In the Attachment, I explain each major forced outage and state the actions NIPSCO has already taken or is able to take to prevent each outage from occurring again.

Q8. Does Confidential Attachment 4-B comply with the Commission's October 29, 2019 Order in Cause No. 38706-FAC-124 ("FAC-124 Order")?

A8. Yes. In its FAC-124 Order, the Commission directed NIPSCO to provide in its future quarterly FAC filings, a root cause analysis for forced outages when such an analysis has been completed at the time of the FAC filing. That information is provided in Confidential Attachment 4-B.

Q9. Does this conclude your prepared direct testimony?

A9. Yes.

VERIFICATION

I, David Saffran, Generation Business Systems Administrator in the Operations Management Reporting division of Northern Indiana Public Service Company LLC, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.



David Saffran

Dated: May 23, 2025

Major Forced Outage Report (Q1, 2025)

Michigan City 12	The unit was taken out of service due to a condenser tube leak.
January 22	Maintenance found the ventilator valve was bleeding through and steam cut the tubes.
112 hours	The cut tubes were plugged, and the valve repaired.
R. M. Schahfer 16A	The unit was taken out of service due to high blade path temperature spread during startup.
January 17	The fuel nozzles were found to be cracked and needed to be replaced.
704 hours	New fuel nozzles were procured and replaced.
R. M. Schahfer 17	Boiler tube leak in superheat platen.
January 15 *272 hours*	The initial cause was an improperly bent tube that created a restriction and caused overheating. This resulted in a chain reaction that damaged the surrounding tubes. The sections of failed and damaged tubes were replaced.
R. M. Schahfer 18	Boiler tube leak on the southwest water wall.
January 29	The leak appears to be due to falling slag.
150 hours	Replaced tubes and pad welded where needed.
R. M. Schahfer 18 February 16 *1,052 hours*	**Boiler tube leak on southwest wall** The unit tripped due to high vibration bearing vibration indications on all rotor bearings. The contractor found L-1 turbine blade had liberated from its root and fell into the condenser. The rotor was removed and sent out for repair.

Confidential Attachment 4-B (Redacted)
Cause No. 38706-FAC-147

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. 202-26-46
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	)))))	Order No. 202-26-47

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

Exhibit 15
Saffran Q2 2025 Outage Testimony

OFFICIAL
EXHIBITS

IURC
PETITIONER'S
EXHIBIT NO. 4
10-14-25 AT
DATE REPORTER

VERIFIED DIRECT TESTIMONY OF DAVID SAFFRAN

Q1. Please state your name, title, and business address.

A1. My name is David Saffran. My title is Generation Business Systems Administrator in the Operations Management Reporting division of Northern Indiana Public Service Company LLC ("NIPSCO" or the "Company"). My business address is 2755 Raystone Drive, Valparaiso, Indiana 46383.

Q2. Please describe your educational and employment background.

A2. I hold an Associate degree in Electronic Systems Technology from the Community College of the Air Force, an Associate degree in Aerospace Ground Equipment Technology from the Community College of the Air Force and have attended classes for three years working towards a Bachelor of Science degree in Computer Networking Information Technology at Purdue Northwest. I have been employed by NiSource Inc. or NIPSCO since May of 2004 in a variety of technical, supervisory, and administrative positions.

Q3. What are your responsibilities as Generation Business Systems

Administrator in the Operations Management Reporting division of NIPSCO?

A3. My current responsibilities include managing NIPSCO's various business systems and programs, recording data concerning Generation's operational and maintenance performance, and analyzing the results to identify adverse trends and recommend corrective actions to improve performance. In addition, I am responsible for submitting various NIPSCO Generation reports and filings to local, state, and federal agencies such as the Indiana Utility Regulatory Commission ("Commission"), Midcontinent Independent System Operator, Inc., North American Electric Reliability Council, Federal Energy Regulatory Commission ("FERC") and Indiana Department of Natural Resources ("DNR").

Q4. Are you familiar with the Company's Verified Petition, including the exhibits attached thereto, initiating this proceeding, a copy of which has been marked Attachment 1-A?

A4. Yes.

Q5. What is the purpose of your direct testimony in this proceeding?

A5. The purpose of my testimony is to provide information relevant to Paragraph 6 of Exhibit A - Settlement Terms, attached to the Stipulation and Agreement filed October 16, 2007 in Cause No. 38706-FAC71-S1 approved by the Commission on January 30, 2008 ("FAC71-S1 Agreement") and Paragraph 6(f.) of the Stipulation and Agreement filed September 23, 2009 in Cause No. 38706-FAC80-S1 approved by the Commission on November 4, 2009 ("FAC80-S1 Agreement") (collectively, the "Reporting Agreements"). Paragraph 6 of the FAC71-S1 Agreement calls for NIPSCO to submit testimony in its quarterly FAC proceedings regarding major forced outages that occur within the pertinent FAC timeframe. Under this provision, NIPSCO must describe the length and cause of each major forced outage, generating unit involved, and proposed solutions to prevent such outages from occurring in the future. In addition to the above provision regarding the details of each major forced outage, Paragraph 6(f.) of the FAC80-S1 Agreement calls for NIPSCO to file testimony describing the details of and the steps taken to minimize such major forced outages in the future. Paragraph 6(f.) of the FAC80-S1 Agreement defines a "major forced outage" as a unit forced outage lasting longer than three (3) consecutive days.

Q6. Are you sponsoring any attachments to your testimony?

A6. Yes. I am sponsoring Attachment 4-A and Confidential Attachment 4-B, both of which were prepared by me or under my direction and supervision. Attachment 4-A describes each major forced outage NIPSCO's generating units experienced during the second quarter of 2025, which is the reconciliation period in this FAC proceeding. Confidential Attachment 4-B contains root-cause analysis reports regarding the outages listed in Attachment 4-A that were complete at the time of this filing.

Q7. Does Attachment 4-A comply with the Reporting Agreements?

A7. Yes. In the Attachment, I explain each major forced outage and state the actions NIPSCO has already taken or is able to take to prevent each outage from occurring again.

Q8. Does Confidential Attachment 4-B comply with the Commission's October 29, 2019 Order in Cause No. 38706-FAC-124 ("FAC-124 Order")?

A8. Yes. In its FAC-124 Order, the Commission directed NIPSCO to provide in its future quarterly FAC filings, a root cause analysis for forced outages when such an analysis has been completed at the time of the FAC filing. That information is provided in Confidential Attachment 4-B.

Q9. Does this conclude your prepared direct testimony?

A9. Yes.

VERIFICATION

I, David Saffran, Generation Business Systems Administrator in the Operations Management Reporting division of Northern Indiana Public Service Company LLC, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.

David Saffran

Dated: August 18, 2025

Major Forced Outage Report (Q2, 2025)

R. M. Schahfer 16A June 11 *153 hours*	Main lube oil pump motor failed. Electric maintenance found the motor windings were grounded. A new motor was purchased to replace the failed motor. The unit was returned to service June 17.
R. M. Schahfer 16B June 16 *75 hours*	Turbine lube oil leak around #5 exhaust bearing. The investigation found the leak originated from a seal-tight connection for a temperature probe. The oil ran from the probe down the wire harness before dripping onto the ground, making its origin difficult to identify. The connection was tightened and epoxy applied around the connector to prevent future leaks.
R. M. Schahfer 18 February 16 *2,980 hours*	**Boiler tube leak on southwest wall.** The unit tripped due to high vibration. Bearing vibration indications on all rotor bearings. This event was reported in FAC 147. The contractor found L-1 turbine blade had liberated from its root and fell into the condenser. The rotor was removed and sent out for repair. Unit placed in reserve status on 6/20 and placed online on 6/23.
Norway Hydro June 6 *93 hours*	Unit 4 governor failed—no other units available. The proportional valve failed, and no other units were available; Unit 3 was waiting for brake ring repairs, Unit 2 was off for an oil leak, and Unit 1 was off for bound wicket gates. The valve was replaced and the unit placed back in service at minimum load.

Confidential Attachment 4-B (Redacted)

Confidential - Excluded from public access per Court Records Rule 5

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. 202-26-46
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	)))))	Order No. 202-26-47

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

Exhibit 16
Saffran Q3 2025 Outage Testimony

VERIFIED DIRECT TESTIMONY OF DAVID SAFFRAN

Q1. Please state your name, title, and business address.

A1. My name is David Saffran. My title is Generation Business Systems Administrator in the Operations Management Reporting division of Northern Indiana Public Service Company LLC ("NIPSCO" or the "Company"). My business address is 2755 Raystone Drive, Valparaiso, Indiana 46383.

Q2. Please describe your educational and employment background.

A2. I hold an Associate degree in Electronic Systems Technology from the Community College of the Air Force, an Associate degree in Aerospace Ground Equipment Technology from the Community College of the Air Force and have attended classes for three years working towards a Bachelor of Science degree in Computer Networking Information Technology at Purdue Northwest. I have been employed by NiSource Inc. or NIPSCO since May of 2004 in a variety of technical, supervisory, and administrative positions.

Q3. What are your responsibilities as Generation Business Systems

Administrator in the Operations Management Reporting division of NIPSCO?

A3. My current responsibilities include managing NIPSCO's various business systems and programs, recording data concerning Generation's operational and maintenance performance, and analyzing the results to identify adverse trends and recommend corrective actions to improve performance. In addition, I am responsible for submitting various NIPSCO Generation reports and filings to local, state, and federal agencies such as the Indiana Utility Regulatory Commission ("Commission"), Midcontinent Independent System Operator, Inc., North American Electric Reliability Council, Federal Energy Regulatory Commission ("FERC") and Indiana Department of Natural Resources ("DNR").

Q4. Are you familiar with the Company's Verified Petition, including the exhibits attached thereto, initiating this proceeding, a copy of which has been marked <u>Attachment 1-A</u>?

A4. Yes.

Q5. What is the purpose of your direct testimony in this proceeding?

A5. The purpose of my testimony is to provide information relevant to Paragraph 6 of Exhibit A - Settlement Terms, attached to the Stipulation and Agreement filed October 16, 2007 in Cause No. 38706-FAC71-S1 approved by the Commission on January 30, 2008 ("FAC71-S1 Agreement") and Paragraph 6(f.) of the Stipulation and Agreement filed September 23, 2009 in Cause No. 38706-FAC80-S1 approved by the Commission on November 4, 2009 ("FAC80-S1 Agreement") (collectively, the "Reporting Agreements"). Paragraph 6 of the FAC71-S1 Agreement calls for NIPSCO to submit testimony in its quarterly FAC proceedings regarding major forced outages that occur within the pertinent FAC timeframe. Under this provision, NIPSCO must describe the length and cause of each major forced outage, generating unit involved, and proposed solutions to prevent such outages from occurring in the future. In addition to the above provision regarding the details of each major forced outage, Paragraph 6(f.) of the FAC80-S1 Agreement calls for NIPSCO to file testimony describing the details of and the steps taken to minimize such major forced outages in the future. Paragraph 6(f.) of the FAC80-S1 Agreement defines a "major forced outage" as a unit forced outage lasting longer than three (3) consecutive days.

Q6. Are you sponsoring any attachments to your testimony?

A6. Yes. I am sponsoring Attachment 4-A and Confidential Attachment 4-B, both of which were prepared by me or under my direction and supervision. Attachment 4-A describes each major forced outage NIPSCO's generating units experienced during the third quarter of 2025, which is the reconciliation period in this FAC proceeding. Confidential Attachment 4-B contains root-cause analysis reports regarding the outages listed in Attachment 4-A that were complete at the time of this filing.

Q7. Does Attachment 4-A comply with the Reporting Agreements?

A7. Yes. In the Attachment, I explain each major forced outage and state the actions NIPSCO has already taken or is able to take to prevent each outage from occurring again.

Q8. Does Confidential Attachment 4-B comply with the Commission's October 29, 2019 Order in Cause No. 38706-FAC-124 ("FAC-124 Order")?

A8. Yes. In its FAC-124 Order, the Commission directed NIPSCO to provide in its future quarterly FAC filings, a root cause analysis for forced outages when such an analysis has been completed at the time of the FAC filing. That information is provided in Confidential Attachment 4-B.

Q9. Does this conclude your prepared direct testimony?

A9. Yes.

VERIFICATION

I, David Saffran, Generation Business Systems Administrator in the Operations Management Reporting division of Northern Indiana Public Service Company LLC, affirm under penalties of perjury that the foregoing representations are true and correct to the best of my knowledge, information and belief.



David Saffran

Dated: November 19, 2025

Major Forced Outage Report (Q3, 2025)

Michigan City 12 August 15 *84 hours*	1B aeration blower motor failed and tripped the 480-volt breaker. The 1B blower motor shorted to ground, and blower 3B was not developing adequate pressure. A minimum of two blowers is required for proper operation. The 1B blower motor and 3B blower were replaced.
R. M. Schahfer 16A July 18 *240 hours*	Turbine flame scanner #14 out of service and spark rods not igniting. A secondary problem concerning damaged fuel nozzles and combustion can baskets was discovered during startup and forced the unit offline. The fuel nozzles and baskets were replaced and the unit placed in service.
R. M. Schahfer 16A August 21 *976 hours*	Unit 16A transitioned to a forced outage after high vibration was experienced during operation. A borescope inspection showed significant blade damage to the forward compressor. Repairs are currently ongoing and expect to be completed at the end of April 2026.
R. M. Schahfer 16B August 6 *1,331 hours*	The unit stalled twice at 2,375 rpm while in startup. This prompted a borescope inspection. The inspection revealed damage to the compressor section of the turbine beginning in Row 9, with heavy damage throughout the mid and aft compressor sections. The turbine assembly was removed and sent out for inspection and repair. The unit is expected to be available mid-February 2026.
R. M. Schahfer 17 July 1 *182 hours*	The unit was taken offline due to a boiler wall tube leak on the southwest corner. The root cause was wall thinning, likely due to falling slag. Three dutchmen were used to replace the failed tubes.
R. M. Schahfer 17 August 7 *264 hours*	The unit was removed from service for an unsafe boiler flue gas leak. The root cause was due to normal wear in a harsh flue gas environment.

	Contractors completed all required ductwork repairs and the unit placed in service.
R. M. Schahfer 17 August 18 *125 hours*	Boiler wall tube leaks. The root cause was washout likely due to boiler cleaning or a malfunctioning soot blower. Three dutchmen were used to replace the bad tubes.
R. M. Schahfer 17 September 6 *201 hours*	Boiler wall tube leaks on the lower slope. The likely cause was due to wall thinning caused by falling slag. A dutchmen and two pad welds were required to replace bad tubes and repair previously installed dutchmen.
R. M. Schahfer 18 July 9 *1,996 hours*	The unit tripped due to high turbine bearing vibration indications on all rotor bearings. Initial inspections inside the upper condenser hot well revealed significant damage to the upper portion of the condenser tubes on the governor end. One of the L-0 blades on the governor end liberated approximately 1/3 of the way down from the tip. Management is weighing options. The unit is currently scheduled to retire December 31, 2025
Norway Hydro June 6 *559 hours*	All turbine units were shut down three times due to low river water and low dissolved oxygen readings. This is an Out of Management Control event. No additional action is needed.

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. 202-26-46
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	)))))	Order No. 202-26-47

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

Exhibit 17
DOE Order No. 202-20-2

Department of Energy
Washington, DC 20585

Order No. 202-20-2

Pursuant to the authority vested in the Secretary of Energy by section 202(c) of the Federal Power Act (FPA), 16 U.S.C. § 824a(c), and section 301(b) of the Department of Energy Organization Act, 42 U.S.C. § 7151(b), and delegated to the Deputy Secretary of Energy by paragraph 1.11(A) of Delegation Order No. 00-001.00G (Apr. 10, 2018), and re-delegated to the Assistant Secretary for Electricity on September 6, 2020, and for the reasons set forth below, I hereby determine that an emergency exists in California due to a shortage of electric energy, a shortage of facilities for the generation of electric energy, and other causes, and that issuance of this Order will meet the emergency and serve the public interest.

On September 6, 2020, the California Independent System Operator (CAISO), the Regional Transmission Organization whose service territory includes California and a portion of Nevada, filed a *Request for Emergency Order Pursuant to Section 202(c) of the Federal Power Act* (Application) with the United States Department of Energy (Department) "to preserve the reliability of bulk electric power system."

Since August, California has experienced several periods of extreme heat, some of which have resulted in rolling blackouts. On September 2, 2020, California Governor Gavin Newsom issued an emergency proclamation to help alleviate the stress on the state's power grid due to an "Extreme Heat Event." In declaring a statutory emergency, the proclamation cited a number of factors and observations, including the following:

- "[B]eginning on September 2, 2020, a significant heat wave struck California, bringing widespread temperatures well in excess of 100 degrees throughout the State;"
- "[T]he National Weather Service [has] issued multiple Excessive Heat Warnings within [California];"
- "[T]he Extreme Heat Event has and will continue to put significant demand and strain on California's energy grid; and"
- "[T]he Extreme Heat Event is expected to last through at least September 7, 2020."

The proclamation authorizes emergency use of stationary generators, portable generators, and "auxiliary engines by ocean-going vessels berthed in California ports," and directs the state's Air Resources Board to "exercise maximum discretion to permit the use of stationary and portable generators or auxiliary ship engines to reduce the strain on the energy infrastructure and increase energy capacity." The proclamation also

suspends "[a]ny permit, regulation or law prohibiting, restricting or penalizing the use of stationary or portable generators or auxiliary ship engines" as allowed by the proclamation order.

On September 3, the CAISO issued a statewide flex alert for September 5-7, encouraging voluntary load reduction between 3:00 p.m. and 9:00 p.m. local time each day. The alert warns that consumers should "be prepared for potential power outages, both planned and unplanned during heat waves, especially in extremely high temperatures that last multiple days," noting that "[h]ot weather can also impact generation and transmission equipment, as it runs harder and longer with less time to cool, which can cause machinery failure." The alert explains that there is little energy available to import due to high heat predicted throughout the West, and that the wildfires in the state may take out transmission lines or cause lines to be shut down for the safety of firefighters in the area.

The CAISO notes that "[e]lectric demand forecasts have continued to increase since the issuance of the California Governor's emergency proclamation and the CAISO balancing authority area has lost additional generation supply because of wildfires." Application at 3. To address the situation, the "CAISO has started to direct all generators in its balancing authority area to produce to their maximum capability during certain times of the day," and has gone so far as to allow, when reliable and safe based on currently operating conditions, "certain generators to generate more than their interconnection capacity to provide additional power to the grid." *Id.* at 3. The impetus for the Application, however, arose on September 5, 2020, when the operator of the natural gas-fired resources identified in Exhibit A of the Application informed the CAISO that it could not produce to its maximum generation capability without exceeding its federal air quality or other permit limitations. *Id.* "The CAISO is informed and believes these limitations involve both permit limitations under federal law for nitrogen oxide emissions and ammonia releases as well as a limitations regarding fuel and ammonia throughput." *Id*.

The CAISO requests "that the Secretary issue an order immediately, effective September 6, 2020, authorizing specific electric generating units located within the CAISO balancing authority area to operate at their maximum generation output levels when directed to do so by the CAISO, notwithstanding air quality or other permit limitations." *Id.* at 1. The generating units specified are units 1 - 5 at the Walnut Creek Energy Park in the City of Industry, California; units 5/6 and 7/8 at the El Segundo Energy Center in El Segundo, California; and units 1 - 4 at the Long Beach Generating Station located in Long Beach, California. *Id.* For purposes of this Order, these units are referred to as the "Specified Resources." Collectively, they represent up to as much as 100 MW. The CAISO requests "such order be entered today, September 6, 2020, and remain effective for a period of seven (7) days, without prejudice to the possible issuance of further orders as necessary to address the emergency…[to] ensure additional supply is

available during a period in which California may continue to experience extreme weather and wildfires that have forced generation out of service." *Id*. at 2.

Given the emergency nature of the expected load stress, the responsibility of the CAISO to ensure maximum reliability on its system, and the ability of the CAISO to identify and dispatch generation necessary to meet the additional load, I have determined that additional dispatch of the Specified Resources is necessary to best meet the emergency and serve the public interest for purposes of FPA section 202(c). Because the additional generation may result in a conflict with environmental standards and requirements, I am authorizing only the necessary additional generation, with reporting requirements as described below.

FPA section 202(c)(2) requires the Secretary of Energy to ensure that any 202(c) order that may result in a conflict with a requirement of any environmental law be limited to the "hours necessary to meet the emergency and serve the public interest, and, to the maximum extent practicable," be consistent with any applicable environmental law and minimize any adverse environmental impacts. The CAISO anticipates that this Order may result in exceedance of National Ambient Air Quality Standards under the Clean Air Act and notes that the Specified Resources are located in different communities within California and should not result in any disproportionate impact on a single community. *Id.* at 4. To minimize adverse environmental impacts, this Order limits operation of dispatched units to the times and within the parameters determined by the CAISO for reliability purposes.

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

A. From September 6, 2020, to September 13, 2020, in the event that the CAISO determines that generation from the Specified Resources is necessary to meet the exceptional levels of electricity demand that the CAISO anticipates in California, I direct the CAISO to dispatch such unit or units and to order their operation only as needed to maintain the reliability of the power grid in California between the hours of 14:00 Pacific Daylight Time and 22:00 Pacific Daylight Time on days when the demand on the CAISO system exceeds expected energy and reserve requirements.

B. The CAISO shall select the combination of units that meets the reliability emergency and minimizes environmental impact. Consistent with good utility practice, the CAISO shall exhaust all reasonably and practically available resources, including demand response and identified behind-the-meter generation resources to the extent that such resources provide support to maintain grid reliability, prior to dispatching the Specified Resources.

C. By September 21, 2020, the CAISO shall report all dates between September 6, 2020, and September 13, 2020, on which the Specified Resources were

operated, the hours of operation, and the estimated air emissions (including nitrogen oxides and ammonia releases) and fuel and ammonia throughput associated with operating each unit. The CAISO shall submit a final report by October 13, 2020, with any revisions to the information reported on September 21.

D. This Order shall be effective upon its issuance, and shall expire at 23:59 Pacific Daylight Time on September 13, 2020, with the exception of the reporting requirements in paragraph C. Renewal of this Order, should it be needed, must be requested before this Order expires.

Issued in Washington, D.C. this 6th day of September, 2020.

Bruce J. Walker

Digitally signed by Bruce J. Walker
Date: 2020.09.06 17:19:49 -04'00'

Bruce Walker
Assistant Secretary for Electricity

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. 202-26-46
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	)))))	Order No. 202-26-47

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

Exhibit 19
NIPSCO CPCN Discovery Responses

OFFICIAL
EXHIBITS

IURC
JOINT - NIPSCO / CAC
EXHIBIT No. 6
7-11-24 AR
DATE REPORTER

Joint NIPSCO-CAC Exhibit 6

Witness Augustine

NIPSCO's Public Responses to CAC Data Requests 1-11, 1-12, 1-13, 1-14, 3-14, 3-15, 3-19, 5-2, 5-4, 6-5, 7-1, 10-1, 10-2, 10-3, 17-1, 23-1, 24-1, 25-2, 28-1, and 32-1

Cause No. 45947
Northern Indiana Public Service Company LLC's
Supplemental Responses to
Citizens Action Coalition of Indiana, Inc.'s First Set of Data Requests

CAC Request 1-011:
Re: NIPSCO Exhibit 7 (Direct Testimony of Augustine), page 28. With regards to the "latest information associated with MISO's seasonal resource adequacy construct": (a) Please identify the referenced "time of the analysis" (b) Please identify the seasonal capacity accreditation for intermittent resources used in the 2023 Portfolio Analysis. (c) Please identify the seasonal planning reserve margin targets used in the 2023 Portfolio Analysis. (d) Please state whether capacity accreditation under MISO's seasonal resource adequacy construct has changed since the values used in the 2023 Portfolio Analysis. If so, please identify how the values have changed. (e) Please state whether seasonal planning reserve margin targets have changed since the targets used in the 2023 Portfolio Analysis. If so, please identify how the targets have changed.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request seeks information that is confidential, proprietary, and/or trade secret.
Response:
Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response: (a) The assumptions for the 2023 portfolio analysis were developed at the end of 2022 and finalized in January 2023. (b) As in the 2021 IRP, NIPSCO's 2023 portfolio analysis evaluated seasonal capacity accreditation and seasonal reserve margin targets for MISO's summer and winter seasons. The summer and winter seasonal capacity accreditation assumptions used in the 2023 portfolio analysis for wind and solar resources are documented in the "Generic Capacity Credit" tab in Confidential Attachment 7-C to Mr. Augustine's direct testimony and are summarized as follows: NIPSCO assumed that wind resources would receive a winter capacity accreditation of 25% throughout the study period and a summer capacity accreditation of 16.3% throughout the study period. NIPSCO assumed that solar resources would

receive a winter capacity accreditation of 6.6% throughout the study period, with solar capacity accreditation changing over time in accordance with the table below:

Solar Capacity Credit Assumptions

2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
50.0%	47.9%	45.8%	43.8%	41.7%	39.6%	37.5%	35.4%	33.3%	31.3%

2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
29.2%	27.1%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%	25.0%

(c) As in the 2021 IRP, NIPSCO's 2023 portfolio analysis evaluated seasonal capacity accreditation and seasonal reserve margin targets for MISO's summer and winter seasons. The assumed summer planning reserve margin target used in the 2023 portfolio analysis was 7.4%, and the assumed winter planning reserve margin target used in the 2023 portfolio analysis was 25.5%.

(d) Estimates of seasonal capacity accreditation remain dynamic at MISO, particularly regarding forward-looking views of the effective load carrying capability ("ELCC") for intermittent resources. MISO produced a Wind and Solar Capacity Report for Planning Year 2023-2024 in March 2023 (https://cdn.misoenergy.org/2023%20Wind%20and%20Solar%20Capacity%20Credit%20Report628118.pdf) and identified the following seasonal capacity accreditations for 2023-24:

	Summer	Winter
Solar	50%	5%
MISO-Wide Wind	18.1%	40.3%
Zone 6 Wind	13.8%	29.6%

In April 2023, MISO published assumptions documentation for its long-range transmission planning ("LRTP") analysis that included summer accreditation expectations for solar and wind over time. In this documentation, solar ELCC was projected to start at 50% in 2023, falling to 20% by 2037, while wind ELCC was projected to be constant at 16.6% over the whole study period. These assumptions are documented on page 4 in the following report:

https://cdn.misoenergy.org/20230308%20PAC%20Item%2008a%20Futures%20Refresh%20Assumptions%20Book628109.pdf.

While these two reports published at nearly the same time illustrate the dynamic nature of capacity accreditation assumptions at MISO right now, they also demonstrate that no significant accreditation changes have been made since NIPSCO developed the values used in the 2023 portfolio analysis.

(e) The latest summer and winter seasonal planning reserve margin targets remain at 7.4% and 25.5%, respectively, consistent with the assumptions used in the 2023 portfolio analysis. These targets were set in MISO's Loss of Load Expectation ("LOLE") Study Report for Planning Year 2023-2024, which can be found at the following location: https://cdn.misoenergy.org/PY%202023-2024%20LOLE%20Study%20Report626798.pdf. As part of this study, MISO performed some "outyear" analysis that provided perspectives on the potential change in seasonal reserve margins over time (See Section 10, Appendix E of the LOLE report referenced above). In these outyear projections, MISO suggested the potential for summer reserve margins to increase slightly, while winter reserve margins were projected to remain around 25%. NIPSCO will continue to track MISO analysis on this topic, including the next LOLE report, which will set the targets for next year's Planning Resource Auction.

Supplemental Response:

(e) See the supplemental direct testimony of Pat Augustine at Question / Answer 10.

Cause No. 45947
Northern Indiana Public Service Company LLC's
Objections and Responses to
Citizens Action Coalition of Indiana, Inc.'s First Set of Data Requests

CAC Request 1-012:
Please identify and produce for each of the following the most recent forecasts obtained, created, or reviewed by NIPSCO: (a) Natural gas prices (b) Coal prices (c) MISO energy prices (d) MISO capacity prices (e) NOx emission allowance prices
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request seeks information that is confidential, proprietary, and/or trade secret.
Response:
Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response: CRA's Fall 2023 commodity price update is provided as CAC Request Confidential 1-012 Attachment A. This includes the most recent market forecasts obtained and reviewed by NIPSCO for the requested fuel, MISO market, and emission allowance prices.

CAC Request 1-013:

Re: NIPSCO Exhibit 7 (Direct Testimony of Augustine) at page 32 line 11 to page 33 line 5. With regards to the evaluation of the potential conversion of one or two units at the Schahfer plant:

(a) Please identify and produce all NIPSCO analyses of the potential conversion, including all workpapers, modeling input and output files, and other supporting documents.

(b) Please state whether NIPSCO has analyzed the net present value revenue requirement ("NPVRR") of converting the Schahfer coal units to gas compared to the NPVRR of the Schahfer gas peaker plant proposed in this proceeding. If so, please produce such analysis and any supporting workpapers, modeling input and output files, or other documents. If not, please explain why not.

(c) Please identify how the fast-start, quick-ramping, and reliability characteristics of converted Schahfer coal units to gas would compare to those same characteristics for the proposed Schahfer gas peaker.

Objections:

NIPSCO objects to this Request on the grounds and to the extent that this Request seeks information that is confidential, proprietary and/or trade secret.

Response:

Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response:

(a) NIPSCO's analysis of the potential conversion of one or two units at the Schahfer plant was conducted as part of its 2018 IRP, and all workpapers and summaries of modeling inputs and outputs can be found in CAC Request 1-013 Confidential Attachment A, which is Confidential Appendix D to the 2018 IRP. The following information was provided in the appendices:

- Coal-to-gas conversion portfolio details in the "Portfolio Legend" tab;
- Operational parameter assumptions for the Schahfer Unit conversion candidates on the "Existing Fleet Parameters" tab;

- Expectations for ongoing fixed operations and maintenance ("FOM") costs, coal-to-gas conversion capital costs, and ongoing capital expenditures for the conversion candidates on the "Unit FOM Capital – Retirements" tab within Portfolios 6b and 6c;
- Detailed annual revenue requirement projections and a summary of the projected net present value of revenue requirements ("NPVRR") for the two coal-to-gas conversion portfolios (Portfolios 6b and 6c) across all four IRP scenarios in the "Rev Req Components – Retirements" tab;
- Additional portfolio cost and financial output reports in the "Ret6b Summary," "Ret6c Summary," "Ret6b Contracts," "Ret6c Contracts," "Ret6b Resources," "Ret6c Resources," "DetailedFinOutputRetirements 6b," and "DetailedFinOutputRetirements 6c" tabs.

(b) NIPSCO has not additionally analyzed the net present value of revenue requirements ("NPVRR") of converting the Schahfer coal units to gas compared to the CT Project proposed in this proceeding because the gas peaker provides the load following generation and supporting reliability attributes needed and identified in the 2021 IRP and in NIPSCO's subsequent diligence associated with this application, including the Flexible Resource Analysis. The 2021 IRP analyzed a set of replacement portfolios across dispatchability and emissions criteria. Based on that analysis, the portfolio with a new gas peaker scored the highest and provides required flexibility to the NIPSCO fleet.

(c) The proposed CT Project is anticipated to have a start time as low as 11 minutes and a ramp rate of approximately 140 MWs per minute. Final performance data is dependent on the results of the competitive RFP for the CT equipment. Converting the existing units to natural gas would have start and ramp times similar to their current status as coal-fired generation with ramp rates of 3 MWs per minute, and a start up target of 22 hours after a 1 hour notice. The attributes associated with either the coal-fired or natural gas-fired thermal steam units are attuned to base load units operating over long periods of time with little variability in the energy produced. The attributes of the combustion turbines, specifically the very fast start up times and very quick ramp rates, are supportive of energy sources working in conjunction with renewable energy sources to "fill in the gap" related to the intermediate nature of renewable energy resources. As such, converting the existing Schahfer units to natural gas will not follow the load and provide the flexibility attributes that NIPSCO requires.

Cause No. 45947
Northern Indiana Public Service Company LLC's
Objections and Responses to
Citizens Action Coalition of Indiana, Inc.'s First Set of Data Requests

CAC Request 1-014:

Re: NIPSCO Exhibit 7 (Direct Testimony of Augustine) at page 35. With regards to the effective load carrying capability ("ELCC") discussed therein:

(a) Please identify for each of the years 2023 through 2052 the ELCC for four-hour duration storage resources assumed in the 2023 Portfolio Analysis.

(b) Please identify and produce any analysis, study, or other document supporting the assumption that the ELCC for four-hour duration storage resources would decline to 70% by 2040.

(c) Please explain the basis for the contention that a gas peaker "is likely to have a stable ELCC around 95%," and identify and produce any analysis, study, or other document supporting that contention.

(d) Please state whether the ELCC values for four-hour duration storage and a new gas peaker plant assumed in the 2023 Portfolio Analysis are consistent with MISO's most recent Seasonal Accredited Capacity values for those resources. If not, please explain how use of MISO's most recent values would impact the results of the 2023 Portfolio Analysis.

Objections:

NIPSCO objects to this Request on the grounds and to the extent that this Request seeks information that is confidential, proprietary, and/or trade secret.

Response:

Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response:

(a) NIPSCO's 2023 portfolio analysis included a fundamental dispatch analysis that was conducted for the years 2023-2042, followed by an additional ten years of extrapolation and revenue requirement calculations. The ELCC assumption for four-hour duration storage resources for the 2023-2042 time period is provided below and also summarized in the "Generic Capacity Credit" tab of Confidential Attachment 7-C to Mr. Augustine's direct testimony. Given the extrapolation methodology used beyond 2042, the analysis implicitly assumes the ELCC values remain constant beyond 2042.

2023	88%
2024	87%
2025	86%
2026	85%
2027	84%
2028	83%
2029	82%
2030	81%
2031	79%
2032	78%
2033	77%
2034	76%
2035	75%
2036	74%
2037	73%
2038	72%
2039	71%
2040	70%
2041	70%
2042	70%

(b) MISO has produced recent analysis supportive of the assumption that the ELCC for four-hour duration storage could decline to 70% by 2040. For example, MISO's April 2023 assumptions documentation for its long-range transmission planning ("LRTP") analysis includes an expectation for storage ELCC to decline to 75% by 2037, quite close to the assumption of 73% by 2037 in NIPSCO's 2023 portfolio analysis. This is documented on page 4 of the assumptions found here: https://cdn.misoenergy.org/20230308%20PAC%20Item%2008a%20Futures%20Refresh%20Assumptions%20Book628109.pdf. In addition, MISO's Renewable Integration Impact Assessment report projected a decline in storage ELCC to 64% with 30 GW (ICAP) of storage capacity in the system, declining to as low as 19% with 100 GW (ICAP) of storage capacity. This is documented in Figure RA-32 here: https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf. In addition, research across the industry and in other ISOs suggests that the capacity credit for storage would be expected to drop over time as a result of increasing renewable and storage penetration and when the width of the peak

net load period exceeds the hours of storage duration. See, for example, an NREL study on dynamic storage capacity valuation here: https://www.nrel.gov/docs/fy18osti/71462.pdf.

(c) As a dispatchable thermal resource without duration limitations, a gas peaker unit's ELCC is likely to be influenced most directly by its forced outage rate and not the changing net load profiles in the MISO market over time. In MISO's 2023-2024 Loss of Load Expectation ("LOLE") Study, used to set planning reserve margin targets, forced outage rates and planned maintenance factors were calculated over a five-year (2017-2021) period for thermal units. For combustion turbines greater than 50 MW, the unit type representing the new gas peaker NIPSCO requests approval for in this Cause, MISO identified a 4.07% forced outage rate, which would imply an approximate 96% ELCC. Over the last six MISO LOLE studies, the forced outage rate for this unit type averaged 4.87%, implying an ELCC value just above 95%. See Section 3.2.1 in the 2023-2024 LOLE study here: https://cdn.misoenergy.org/PY%202023-2024%20LOLE%20Study%20Report626798.pdf.

(d) Estimates for seasonal capacity accreditation remain dynamic at MISO, particularly regarding forward-looking views of the effective load carrying capability ("ELCC") for resources like storage. Last year, in June, 2022, The "Managing Reliability Risk in the MISO Footprint" report (https://cdn.misoenergy.org/20220616%20Board%20of%20Directors%20Item%2008a%20Reliability%20Imperative625168.pdf) produced an estimate of an 87.5% capacity credit for battery storage, consistent with the starting point assumed in NIPSCO's 2023 portfolio analysis. And as noted in subpart (b) to this request, MISO's assumptions document for the LRTP analysis documented one potential outlook for storage ELCC, although a lack of operating resources in the market has limited MISO's ability to publish any more recent class-average data. Thus, NIPSCO believes that the ELCC values assumed in the 2023 portfolio analysis remain consistent with the most recent information published by MISO.

CAC Request 3-014:

Please refer to Mr. Augustine's testimony at page 29, lines 5-9.

a. Please explain how the energy communities bonus adder was incorporated for renewable and battery storage projects.
b. Please explain if there was an assumed number of MWs eligible for the energy communities bonus adder or if the bonus adder was evaluated on a project by project basis.
c. If any projects modeled within Aurora qualify for the energy communities bonus adder, please provide the names of those projects as they were modeled in Aurora.

Objections:

Response:

(a) As part of the assumptions development process for the 2023 portfolio analysis, CRA reviewed bids from the 2022 RFP to identify the potential for energy community bonus qualification for new renewable and battery storage projects in the near-term. The near-term tax credit-eligible additions in the portfolios that NIPSCO evaluated included solar and wind PPAs (where the developer is assumed to incorporate any federal tax credit benefits within the PPA price) and new owned battery storage. No battery storage bids in the 2022 RFP were located in energy communities, although NIPSCO has identified the potential for utilizing remaining interconnection rights from Schahfer units 17 and 18 as potential sites for storage that would qualify for the bonus energy communities credit. (See NIPSCO's response to CAC Request 1-005.) Thus NIPSCO focused its modeling of bonus credits on the opportunity for a subset of near-term storage projects to be eligible for the 10% ITC adders.

(b) Although no bidders to NIPSCO's 2022 RFP offered storage projects located within energy communities, NIPSCO and CRA made the assumption that up to 150 MW of new battery storage could be located in an energy community, such as at the Schahfer site, and receive the 10% ITC bonus and a 40% ITC for the total project cost. All near-term solar and wind additions in the portfolios that were evaluated (up to 200 MW of new solar and up to 400 MW

of new wind) were modeled as PPAs with no separate analysis of tax credit eligibility. All long-term generic solar additions were common across the three portfolios NIPSCO evaluated in the 2023 portfolio analysis, with tax credit eligibility assuming prevailing wage and apprenticeship requirements are met and no bonus credit.

(c) The 150 MW of four-hour battery storage in 2026 incorporated in Portfolios 1 and 2 were assumed to qualify for the energy communities 10% ITC bonus adder. In addition, the 125 MW of 4-hour battery storage in 2028 incorporated in Portfolio 3 was assumed to qualify for the same bonus credit. These projects are named "Storage A1_2026" and "Generic 4-Hour Storage_Ref_2028" in the Aurora input database workpapers provided in NIPSCO's supplemental response to CAC Request 1-010.

Cause No. 45947
Northern Indiana Public Service Company LLC's
Supplemental Response to
Citizens Action Coalition of Indiana, Inc.'s Third Set of Data Requests

CAC Request 3-015:
Please refer to the workbook "Gas Peaker_NIPSCO_Confidential Attachment 7-C_09122023", worksheets "Rev Req Components", "Portfolio 1", "Portfolio 2", and "Portfolio 3". Please provide versions of these worksheets that are not hardcoded values and show the supporting calculations, with all formulas and links intact.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request seeks information that is confidential, proprietary, and/or trade secret. The requested worksheets are proprietary information to Charles River Associates and are unavailable
Response:
Please see objections.
Supplemental Response:
CAC Request 3-015 Confidential Attachment A, which contains the requested workbooks with all formulas and links intact, has been provided to the CAC pursuant to terms of a nondisclosure agreement CAC executed with Charles River Associates. CAC Request 3-015 Confidential Attachment A can be provided to any party to this proceeding that executes a separate nondisclosure agreement with Charles River Associates.

Cause No. 45947
Northern Indiana Public Service Company LLC's
Objections and Responses to
Citizens Action Coalition of Indiana, Inc.'s Third Set of Data Requests

CAC Request 3-019:

Please refer to the Flexible Resource Analysis presented in "Gas Peaker_NIPSCO Confidential Attachment 7-D_09122023".

a. Please explain how the charge and discharge of battery storage resources was modeled in the flexible resource analysis.
b. Please explain if battery resources were assumed to only be charged from NIPSCO resources.
c. Please explain if the discharge of battery storage resources was assumed to be a four hour consecutive period limited.
d. Please explain how any cycle limitations were implemented for battery storage resources.

Objections:

Response:

(a) The Flexible Resource Analysis was designed to evaluate and quantify the frequency and duration of NIPSCO's potential future net load exposure based on uncertainty in sub-hourly load, wind output, and solar output. The Flexible Resource Analysis was not designed to evaluate dispatch of individual units. As such, the key outputs were summaries of net load and net load ramps, including evaluations of the frequency and duration of net load exposure events. Thus, the methodology used in the Flexible Resource Analysis did not require NIPSCO to model the charge and discharge of battery resources.

(b) See part (a).

(c) See part (a).

(d) See part (a).

Cause No. 45947
Northern Indiana Public Service Company LLC's
Objections and Responses to
Citizens Action Coalition of Indiana, Inc.'s Fifth Set of Data Requests
[Denotes Confidential Information]

CAC Request 5-002:

Re: NIPSCO response to data request CAC 3-001(a) ("The Flexible Resource Analysis (Confidential Attachment 7-D to Mr. Augustine's direct testimony) specifically pointed to the need for a gas-peaking asset in conjunction with the diverse portfolio of assets NIPSCO is constructing to include existing natural gas, wind, solar, battery storage, and flexible natural gas resources"): Please give a pinpoint citation to the part of NIPSCO's Conf. Attachment 7-D that establishes the need for a gas-peaking asset.

Objections:

NIPSCO objects to this Request on the grounds and to the extent that this Request seeks information that is confidential, proprietary, and/or trade secret.

Response:

Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response:

The Flexible Resource Analysis was not intended to identify a single resource or set of resources, but rather assess how much flexible capacity NIPSCO would require to maintain reliability and mitigate against market risk as dispatchable generation retires and is replaced largely by non-dispatchable generation.

As stated on page 19 of Mr. Augustine's direct testimony, the Flexible Resource Analysis was intended to: "more fully assess the energy adequacy and flexibility characteristics of the IRP's preferred portfolio and to analyze the potential market exposure that could result from increasing reliance on renewable generation. The flexibility study was designed to (i) assess the portfolio's flexibility needs on an inter-hour and intra-hour basis, given the variability and intermittency of renewable resources; and (ii) perform sub-hourly analysis to provide insights into the type of market exposure NIPSCO could face as its portfolio evolves. The flexibility study was conducted to evaluate the risks associated with times of resource unavailability and market purchase exposure."

NIPSCO's Preferred Portfolio F from the 2021 IRP included a new natural gas peaking plant based on NIPSCO's integrated scorecard summary of a range of key planning objectives, as documented in Section 9.3 of the IRP. In that section of the 2021 IRP on p. 257, NIPSCO also noted that "the quantities and characteristics of storage and gas peaking resource additions require further study to confirm reliability can be

maintained and to understand the value of each resource type given ongoing and potential market and policy changes." The Flexible Resource Analysis was one means of performing further study of each resource type, with one major conclusion affirming that long-duration dispatchable resources provide value that shorter-duration resources cannot. Please see slide 8 of Confidential Attachment 7-D, with further detail provided on slide 12.

CAC Request 5-004:

Re: NIPSCO response to data request CAC 1.011(b).

(a) Please explain NIPSCO's or Mr. Augustine's basis for assuming wind will have a 25% winter capacity accreditation throughout the study period.

(b) Please explain NIPSCO's or Mr. Augustine's basis for assuming wind will have a 16.3% summer capacity accreditation throughout the study period

(c) Please explain NIPSCO's or Mr. Augustine's basis for assuming solar will have a winter capacity accreditation of 6.6% throughout the study period.

(d) Regarding the chart at the end of your response to CAC 1.011(b):

(i) Please confirm if the phrase "solar capacity accreditation changing over time" was intended to say "**summer** capacity accreditation changing over time."

(ii) Please explain NIPSCO's or Mr. Augustine's basis for assuming the year-by-year summer capacity accreditations for solar shown in the chart.

Objections:

Response:

(a) NIPSCO initially developed the wind winter capacity accreditation assumption of 25% during the 2021 IRP process, as documented in the "Generic Capacity Credit" tab of Appendix D to NIPSCO's 2021 IRP. As of the time of the 2021 IRP analysis, MISO had been indicating that winter capacity accreditation for wind would likely be higher than prevailing summer accreditation, and NIPSCO relied on multiple MISO data sources for guidance. For example, the MISO Resource Adequacy Subcommittee meeting in February, 2021 indicated a 20% winter capacity accreditation (see slide 22 here: https://cdn.misoenergy.org/20210203%20RASC%20Item%2004a%20Subannual%20Construct%20Presentation%20(RASC010,%20011,%20012)517859.pdf), while MISO reviews of intermediate seasonal accredited capacity based on historical wind resource performance for planning years 2019-20 and 2020-21, (as well as 2021-22 and 2022-23) generally averaged around 25% (see slide 41 here: https://cdn.misoenergy.org/20220824%20RASC%20Item%2007c%20Non-

Thermal%20Accreditation%20Presentation%20(RASC-2019-2%202020-4)626036.pdf). Although MISO's Renewable Integration Impact Assessment report contemplates modestly declining capacity accreditation for wind over time, the 25% assumption was used as representative of the likely long-term expectation for wind resources.

(b) NIPSCO initially developed the wind summer capacity accreditation assumption of 16.3% during the 2021 IRP process, as documented in the "Generic Capacity Credit" tab of Appendix D to NIPSCO's 2021 IRP. The assumption was developed based on MISO's most recent Wind and Solar Capacity Credit report as of the time of the analysis. That report included a MISO-wide assumption of 16.3% for wind resources, as documented here: https://cdn.misoenergy.org/DRAFT%202021%20Wind%20&%20Solar%20Capacity%20Credit%20Report503411.pdf. Although MISO's Renewable Integration Impact Assessment report contemplates modestly declining capacity accreditation for wind over time (see for example, Figure RA-20 here: https://cdn.misoenergy.org/RIIA%20Summary%20Report520051.pdf) and although Zone 6 has historically had lower capacity accreditation than MISO as a whole, the 16.3% assumption was used as representative of the likely long-term expectation for wind resources in NIPSCO's portfolio. This remains broadly consistent with MISO expectations. For example, the latest long-range transmission planning ("LRTP") assumptions include an assumed flat 16.6% wind accreditation over the forecast horizon. See page 4 here: https://cdn.misoenergy.org/20230308%20PAC%20Item%2008a%20Futures%20Refresh%20Assumptions%20Book628109.pdf

(c) NIPSCO initially developed the solar winter capacity accreditation assumption of 6.6% during the 2021 IRP process. This was discussed in detail with stakeholders during the May 20, 2021 public advisory meeting and documented in the meeting minutes in Appendix A to NIPSCO's 2021 IRP. See p. 260 of Appendix A, which includes the following comments from the public advisory meeting: *"Based on NIPSCO's preliminary analysis of the coincidence of solar output with its coincident winter peak loads, the IRP analysis is planning to use 6.6% for the winter solar capacity credit. This number will be further reviewed based on hourly solar shapes that NIPSCO has from its planned solar projects and any future data received in the 2021 RFP. To arrive at the preliminary 6.6% number, CRA looked at the top 10-20 winter peak hours and noted that those tend to occur during the early morning and evening hours. On average, the solar*

output during those hours was approximately 6.6% of nameplate capacity. While geographic diversity could help improve that number in aggregate, and while different projects are likely to have different ratings, this is the general range for what will be used for the winter credit in this IRP." The 6.6% assumption was also consistent with MISO's assumptions for solar accreditation at the time of the analysis of approximately 5% during the winter months (See for example, slide 22 from the MISO Resource Adequacy Subcommittee meeting in February, 2021: https://cdn.misoenergy.org/20210203%20RASC%20Item%2004a%20Subannual%20Construct%20Presentation%20(RASC010,%20011,%20012)517859.pdf)

(d)

(i) Confirmed. The table of numbers at the end of the response to CAC 1-011(b) shows the assumed solar capacity accreditation for the summer season, and the phrase was intended to say "**summer** capacity accreditation changing over time in accordance with the table below."

(ii) NIPSCO initially developed the solar summer capacity accreditation assumptions during the 2021 IRP process, relying largely on information produced by MISO in its Renewable Integration Impact Assessment. The assumptions and associated rationale were documented with stakeholders during NIPSCO's May 20, 2021 public advisory meeting. See in particular slide 21 from the May meeting, which can also be found on page 140 of Appendix A to NIPSCO's 2021 IRP. Recent MISO documentation has remained supportive of this general summer capacity accreditation trajectory. For example, MISO's April 2023 assumptions documentation for its long-range transmission planning ("LRTP") analysis includes an expectation for solar ELCC to decline to 26% by 2035 and 20% by 2037, quite close to the assumption of 25% by 2035 in NIPSCO's 2021 IRP and subsequent 2023 portfolio analysis. This is documented on page 4 of the assumptions found here: https://cdn.misoenergy.org/20230308%20PAC%20Item%2008a%20Futures%20Refresh%20Assumptions%20Book628109.pdf.

Cause No. 45947
Northern Indiana Public Service Company LLC's
Objections and Responses to
Citizens Action Coalition of Indiana, Inc.'s Sixth Set of Data Requests
[denotes confidential]

CAC Request 6-005:

Re: Direct Testimony of Walter at page 29, lines 5-9 ("NIPSCO currently projects capacity factors below 20%, except in the initial months of operation. During these initial months, based on the proposed GHG Rules, either the capacity factors must be limited to 20% or the CTs must achieve the Intermediate Load emission limitations"); NIPSCO response to data request CAC 1.19 (including Conf. Att. A).

(a) Why did NIPSCO's 2021 IRP and 2023 portfolio analysis project [redacted] for the new gas CTs compared to [redacted]?
(b) If the proposed new CTs were limited to no more than 20% capacity factor in the initial months of operation due to federal greenhouse gas emissions rules, how would NIPSCO obtain alternate energy and capacity to meet its retail load requirements? Please provide all analyses, proposals, and documents in NIPSCO's possession used to answer the question.

Objections:

NIPSCO objects to this Request on the grounds and to the extent that this Request seeks information that is confidential, proprietary and/or trade secret.

Response:

Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response:

(a) NIPSCO's 2023 portfolio analysis projects higher capacity factors in 2026 and 2027 as a result of declining reserve margins in the wider MISO market as coal capacity retires and before significant replacement wind, solar, and other capacity is added to the broader system. The Reference Case in NIPSCO's 2021 IRP did not project higher capacity factors for the new peaker in 2026 and 2027 relative to other years, although the Status Quo Extended scenario did project higher capacity factors in 2026 relative to other years (See the "F Resources" tab in Appendix D to NIPSCO's 2021 IRP, which documents capacity factor projections for all resources across the four IRP scenarios). The different projections affirm the fact that multiple factors, including the gas peaker's heat rate, future natural gas prices, regional load growth trends, regional retirement

and expansion activity, and others will determine future capacity factors for the gas peaker plant. Note that even though NIPSCO's 2023 portfolio analysis projected a capacity factor higher than 20% for the partial year of 2026 (which is heavily influenced by the higher capacity factor summer months), annual capacity factors in 2027 and beyond were all projected to be lower than 20%.

(b) NIPSCO would not expect a limit on capacity factors to materially impact accredited capacity for the plant, especially if a change in operations were able to limit run hours during times of energy surplus within the wider MISO market. Even if capacity were derated, NIPSCO expects to have sufficient capacity to meet peak load requirements once the peaker is operational and while the Michigan City coal plant and existing older vintage Schahfer peaking units are operational. This was demonstrated on pages 37 and 38 of Mr. Augustine's direct testimony. As a member of MISO, NIPSCO is able to buy energy from the market as needed and sell energy when generation exceeds retail demand. In 2026 and 2027, NIPSCO expects to maintain a significant energy long position relative to retail load requirements, so minor adjustments in the gas peaker's output would not materially impact NIPSCO's energy position and only marginally lower the net sales position. This was shown on page 38 of Mr. Augustine's direct testimony, with aggregate portfolio generation projections also provided in the "Gen Mix by Portf – Cancellation" tab in Confidential Attachment 7-C to Mr. Augustine's direct testimony.

Cause No. 45947
Northern Indiana Public Service Company LLC's
Supplemental Responses to
Citizens Action Coalition of Indiana, Inc.'s Seventh Set of Data Requests

CAC Request 7-001:

Please refer to the figure labeled "Summer Supply-Demand Balance" at page 37 and the figure labeled "Winter Supply-Demand Balance" at page 38 in Witness Augustine's testimony.

a. Please provide the supporting workbooks, with all formulas and links intact, used to develop each figure.
b. For the reported planning reserve margin, please explain if a coincidence factor was applied to determine the planning reserve margin.
    i. If a coincidence factor was applied, please identify the summer and winter coincidence factors and explain the basis for those factors.
    ii. If a coincidence factor was not applied, please explain why not.
c. If not already included in the supporting workbook used to develop the figures on pages 37-38, please provide the summer and winter resource accreditation for each individual resource within the portfolio.

Objections:

NIPSCO objects to this Request on the grounds and to the extent that this Request seeks information that is confidential, proprietary and/or trade secret.

Response:

Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response:

a. Please find the supporting workbook as CAC Request 7-001 Confidential Attachment A. The "S-D Balance" tab contains referenced figures from Mr. Augustine's testimony. Cells B1 and B2 on this tab allow the user to toggle by portfolio and by summer and winter season.
b. Yes, a coincidence factor was applied to NIPSCO's native peak load forecast to arrive at a peak load estimate coincident with the MISO peak for planning reserve margin calculation purposes. These factors are based on NIPSCO's internal analysis of internal peak relative to the system peak based on historical data. Thus, the peak load in the "Load" tab of CAC Request 7-001 Confidential Attachment A contains load that has already been adjusted by the

coincidence factor and will be lower than the NIPSCO system peak load reported in Chapter 3 of NIPSCO's 2021 IRP. NIPSCO's coincidence factor for summer and winter are included in the "Load" tab of CAC Request 7-001 Confidential Attachment A.

c. The summer and winter resource accreditations are included in CAC Request 7-001 Confidential Attachment A in the "New Resource ELCC" tab.

Supplemental Response:

For sub-parts (a) through (c), refer to the confidential workpaper to Mr. Augustine's supplemental direct testimony which contains NIPSCO's latest summer and winter supply-demand balances, inclusive of the updated MISO PRMR and capacity accreditation information along with the capacity purchases already made by NIPSCO.

Cause No. 45947
Northern Indiana Public Service Company LLC's
Objections and Responses to
Citizens Action Coalition of Indiana, Inc.'s Tenth Set of Data Requests

CAC Request 10-001:
Please provide the forecast of total peak load by each of the four seasons and by year through 2030.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request seeks information that is confidential, proprietary, and/or trade secret.
Response:
Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response: Please refer to the "Demand Monthly Peak" tab in CAC Request 1-010 Confidential Attachment B for NIPSCO's peak load forecast by month. A summary of the forecast of total peak load by each of the four MISO planning seasons by year through 2030 is provided in CAC Request 10-001 Confidential Attachment A. Note that winter includes January, February, and December; spring includes March, April, and May; summer includes June, July, and August; and fall includes September, October, and November.

Cause No. 45947
Northern Indiana Public Service Company LLC's
Objections and Responses to
Citizens Action Coalition of Indiana, Inc.'s Tenth Set of Data Requests

CAC Request 10-002:
Please confirm the portion of 2022 peak load by sector (residential, commercial, and industrial) for each of the four seasons, and if available, by year through 2030.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request solicits an analysis, calculation or compilation which has not already been performed and which NIPSCO objects to performing. NIPSCO is not currently able to track historical peak loads by class, so this data is not available for historical years like 2022. The forecast, however, did develop peaks by class using sample customer load factor information, which is the same forecast used for the 2021 IRP. NIPSCO further objects to this Request on the separate and independent grounds and to the extent that this Request seeks information that is confidential, proprietary and/or trade secret.
Response:
Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response: NIPSCO's forecast of peak load for the residential, commercial, and industrial sectors for each of the four MISO planning seasons by year through 2030 is provided in CAC Request 10-002 Confidential Attachment A. Note that winter includes January, February, and December; spring includes March, April, and May; summer includes June, July, and August; and fall includes September, October, and November. Note that the industrial sector includes firm load served by NIPSCO, including Tier 1 load on the 831/531 rate. Tier 2 and 3 load on the 831/531 rate is not served by NIPSCO and is excluded. Note that the individual monthly peaks by sector may not align, so the seasonal peaks summarized in CAC Request 10-002 Confidential Attachment A are not necessarily coincident. Note that this summary excludes railroad, street lighting, public authority, and company use load. Note that this summary also excludes the gross-up factor for losses that is incorporated when evaluating NIPSCO's system-wide peak for reserve margin planning purposes.

Cause No. 45947
Northern Indiana Public Service Company LLC's
Objections and Responses to
Citizens Action Coalition of Indiana, Inc.'s Tenth Set of Data Requests

CAC Request 10-003:
Please confirm the portion of 2022 peak load by rate class for each of the four seasons, and if available, by year through 2030.
Objections:
NIPSCO objects to this Request on the grounds and to the extent that this Request solicits an analysis, calculation or compilation which has not already been performed and which NIPSCO objects to performing. NIPSCO is not currently able to track historical peak loads by class, so this data is not available for historical years like 2022. The forecast, however, did develop peaks by class using sample customer load factor information, which is the same forecast used for the 2021 IRP. NIPSCO further objects to this Request on the separate and independent grounds and to the extent that this Request seeks information that is confidential, proprietary and/or trade secret.
Response:
Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response: NIPSCO's forecast of peak load at the most granular level available for each of the four MISO planning seasons by year through 2030 is provided in CAC Request 10-003 Confidential Attachment A. Note that winter includes January, February, and December; spring includes March, April, and May; summer includes June, July, and August; and fall includes September, October, and November. Note that the industrial sector includes firm load served by NIPSCO, including Tier 1 load on the 831/531 rate. Tier 2 and 3 load on the 831/531 rate is not served by NIPSCO and is excluded. Note that the individual monthly peaks by rate class may not align, so the seasonal peaks summarized in CAC Request 10-003 Confidential Attachment A are not necessarily coincident. For example, different rate classes may peak in different months within each season, so the sum of the individual industrial rate class components provided in CAC Request 10-003 Confidential Attachment A may not equal the aggregate industrial sector seasonal peak provided in CAC Request 10-002 Confidential Attachment A for certain seasons. Note that this summary also excludes the gross-up factor for losses that is incorporated when evaluating NIPSCO's system-wide peak for reserve margin planning purposes.

Cause No. 45947
Northern Indiana Public Service Company LLC's
Objections and Responses to
Citizens Action Coalition of Indiana, Inc.'s Seventeenth Set of Data Requests
[Denotes Confidential Information]

CAC Request 17-001:

Refer to page 17 of Confidential Attachment A to your response to CAC 1-010. With regards to the statement "[redacted]":

a. Please state whether that statement is referring only to the decision of when between 2026 and 2028 to retire Michigan City 12, or whether it suggests a potential that NIPSCO would retire Michigan City 12 sometime after 2028.
b. Please state whether NIPSCO is currently considering a retirement date for Michigan City 12 after 2028.
    i. If so, please identify any such post-2028 retirement date(s) that is being considered, and explain what factors could lead to selection of such a later retirement date rather than 2028.
    ii. If not, please explain why not.

Objections:

NIPSCO objects to this Request on the grounds and to the extent that this Request seeks information that is confidential, proprietary, and/or trade secret.

Response:

Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response:

a. The statement "[redacted]" refers only to the decision to retire Michigan City 12 between 2026 and 2028.
b. NIPSCO is not currently considering a retirement date for Michigan City 12 after 2028. NIPSCO is currently operating within the action plan parameters of its 2021 IRP.

Note: NIPSCO made all language in the *request* PUBLIC.

Cause No. 45947
Northern Indiana Public Service Company LLC's
Objections and Responses to
Citizens Action Coalition of Indiana, Inc.'s Twenty-Third Set of Data Requests
[Denotes confidential information]

CAC Request 23-001:

Re: NIPSCO Confidential Attachment 7-D (Flexible Resource Analysis):

(a) Please confirm that the system analysis described on slides 54-69 includes the Commonwealth Edison transmission region of Illinois. For anything other than an unequivocal confirmation, please explain in detail.
(b) For the Flexible Resource Analysis, what generation expansion assumptions were used for the Commonwealth Edison transmission region?
(c) For the Flexible Resource Analysis, what load forecast assumptions or methodologies were used for the Commonwealth Edison transmission region?
(d) For the Flexible Resource Analysis, how did Charles River Associates or NIPSCO integrate the wind and solar power buildout requirements contained in the Illinois Power Agency Act as modified by the Climate and Equitable Jobs Act of 2021 (Illinois Public Act 102-0662), codified at 20 ILCS 3855/1-75(c)(1)(C)(i)?
(e) For the Flexible Resource Analysis, how did Charles River Associates or NIPSCO integrate energy efficiency requirements contained in the Illinois Public Utilities Act as modified by the Climate and Equitable Jobs Act of 2021 (Illinois Public Act 102-0662), codified at 220 ILCS 5/8-103B?

Objections:

NIPSCO objects to this Request on the grounds and to the extent that this Request seeks information that is confidential, proprietary, and/or trade secret.

Response:

Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response:

(a) Slides 54-69 include a number of key metrics associated with the Flexible Resource Analysis that were done for both the NIPSCO zone and the broader region. The key findings summarized in slides 7-12 and in slides and graphics labeled "NIPSCO" throughout slides 54-69 of Confidential Attachment 7-D were based *only on analysis performed for NIPSCO's zone.* The separate system analysis, which is summarized in certain graphics and slides labeled "system", included the Commonwealth Edison ("ComEd") zone of PJM in Illinois.

(b) CRA used its regional Eastern Interconnect Aurora model database for the four scenarios NIPSCO developed in its 2021 IRP to develop estimates for future installed capacity in the ComEd zone for the single study year (2030) that was evaluated in the Flexible Resource Analysis. The table below shows the installed capacity assumptions for the ComEd zone in MW for each resource type across the four scenarios.



(c) CRA used PJM's load forecast at the time of the analysis for the ComEd zone for the single study year (2030) that was evaluated in the Flexible Resource Analysis. The table below provides a summary of the monthly energy and peak load assumptions that were used for the ComEd zone.

Month	Energy (MWh)	Peak (MW)
1	8,450,352	14,621
2	7,346,976	13,930
3	7,515,144	12,768
4	6,832,800	12,009
5	7,300,872	15,220
6	8,465,760	20,049
7	9,727,056	20,876
8	9,425,736	20,500
9	7,737,840	17,629
10	7,155,792	12,797
11	7,164,720	12,614
12	8,035,944	14,177

(d) CRA's scenario analysis evaluated a range of renewable buildouts for the ComEd region, ranging to over 3,000 MW of solar and over 13,000 MW of wind by 2030, as documented in subsection (b) to this response. CRA's analysis did not assume any specific targets from Illinois' Climate and Equitable Jobs Act of 2021 for the ComEd zone, given uncertainty in locational siting of projects in ComEd versus the rest of the state (which was not modeled in the Flexible Resource Analysis) and uncertainty associated with specific procurement plans as of the time of the analysis. Given that procurement activities currently lag well behind targets, the approach and assumptions remain reasonable. The Illinois Power Agency's ("IPA") 2024 Long-Term Renewable Resources Procurement Plan report filed with the Illinois Commerce Commission in October 2023 acknowledges that current procurements are currently falling well short of target, and even with successful procurements over the next few years, the IPA acknowledges that the 2030 goal is unlikely to be met (The full report, including the procurement summary in Figure 3-2, can be found here: https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/2024-long-term-plan-20-oct-2023-.pdf)

(e) CRA's analysis incorporated PJM's load forecast for the ComEd zone, which is inclusive of energy efficiency assumptions. CRA did not separately adjust the forecast for energy efficiency targets or requirements from Illinois' Climate and Equitable Jobs Act of 2021.

Cause No. 45947
Northern Indiana Public Service Company LLC's
Objections and Responses to
Citizens Action Coalition of Indiana, Inc.'s Twenty-Fourth Set of Data Requests
[Denotes confidential information]

CAC Request 24-001:

Re: NIPSCO Confidential Attachment 7-D (Flexible Resource Analysis).

(a) On slides 19-22 ("[redacted]"), what type of [redacted] NIPSCO's system in this modeling?

(b) If the answer to part (a) is gas combustion turbine generating capacity, does the analysis on slides 19-22 consider [redacted] shown on page 5-6 of the Simple Cycle Gas Turbine Engineering Study (NIPSCO Conf. Att. 4-A)?

(c) If the answer to part (a) is not gas combustion turbine generating capacity, how does the analysis incorporate [redacted]?

(d) On slides 23-24 ("Analysis of Duration of Short Events"), does the analysis consider [redacted] shown on page 5-6 of the Engineering Study?

Objections:

NIPSCO objects to this Request on the grounds and to the extent that this Request seeks information that is confidential, proprietary, and/or trade secret.

Response:

Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response:

(a) Slides 19-22 of Confidential Attachment 7-D evaluated the change in market exposure risk associated with the addition of *any* flexible, dispatchable capacity. As explained in NIPSCO Witness Augustine's direct and rebuttal testimonies, the Flexible Resource Analysis was designed to assess the energy adequacy and flexibility characteristics of NIPSCO's portfolio from the 2021 IRP and characterize risks associated with potential market exposure. The analysis did not assess specific resource additions beyond the 2021 IRP's preferred portfolio, but instead identified the characteristics of new resource additions that could

help mitigate market exposure risk. See Witness Augustine's direct testimony at Q&A 24 and Witness Augustine's rebuttal testimony at Q&A 16 for additional explanation.

(b) See response to part (a). No resource-specific analysis was performed. Slides 19-22 identified the impacts associated with adding additional MW of any flexible, dispatchable capacity to the portfolio without evaluation of seasonal performance variations.

(c) See response to part (a). No resource-specific analysis was performed. Slides 19-22 identified the impacts associated with adding additional MW of any flexible, dispatchable capacity to the portfolio without evaluation of seasonal performance variations.

(d) The Flexible Resource Analysis considered seasonal capacity ratings and operational assumptions for NIPSCO's existing fleet of resources, including Sugar Creek, and generic assumptions for the 300 MW new peaking facility identified in the 2021 IRP. Since the analysis was designed to assess the 2021 IRP's preferred portfolio and characterize market exposure risks (including the duration of such exposure risks as outlined on slides 23-24 of Confidential Attachment 7-D), it did not consider seasonal performance variation of gas combustion turbines from the referenced Engineering Study, which was conducted after the Flexible Resource Analysis was performed.

Cause No. 45947
Northern Indiana Public Service Company LLC's
Objections and Responses to
Citizens Action Coalition of Indiana, Inc.'s Twenty-Fifth Set of Data Requests
[Denotes confidential information]

CAC Request 25-002:

(a) Regarding "PJM's load forecast at the time of the analysis for the ComEd zone" as referenced in response to data request CAC 23.01(c): Admit that the relevant PJM load forecast at the time of the Flexible Resource Analysis was the 2023 PJM Load Forecast Report dated January 2023, available at https://www.pjm.com/-/media/library/reports-notices/load-forecast/2023-load-report.ashx. For anything other than admission, please explain.

(b) Regarding the 2023 PJM Load Forecast Report referenced in part (a), admit that the Distributed Solar Adjustment to Summer Peak Load for 2030 assumed in the report for the ComEd zone is 701 megawatts, as shown on page 54 of the report. For anything other than admission, please explain.

(c) Regarding the Illinois Power Agency's 2024 Long-Term Renewable Resources Procurement Plan ("LTRRPP") filed with the Illinois Commerce Commission in October 2023, as referenced by NIPSCO in response to data request CAC 23.01(d): admit that at page 149, the Illinois Power Agency states that the Adjustable Block Program encoded in Illinois law at Section 1-75(c)(1)(C) of the Illinois Power Agency Act "targets approximately 12,375,000 RECs delivered annually [...] by 2030 [...] necessitating perhaps up to 7,000 megawatts of new distributed generation and community solar capacity."

(d) Admit that the Adjustable Block Program referenced in Sections 1-75(c)(1)(C)(i) and 1-75(c)(1)(K) of the Illinois Power Agency Act covers RECs from distributed solar and community solar projects and is separate from utility-scale renewable generation REC procurements referenced in Sections 1-75(c)(1)(C)(i), (c)(1)(G)(i), (c)(1)(G)(ii), (c)(1)(G)(iii), and 1-75(c)(1)(G)(v) of the Illinois Power Agency Act.

(e) Admit that, according to page 150 of the Illinois Power Agency's 2024 LTRRPP, "Illinois Shines" is an alternate name for the Adjustable Block Program.

(f) Admit that at page 148 of the Illinois Power Agency's 2024 LTRRPP, the Illinois Power Agency states that the Adjustable Block Program initially opened in January 2019.

(g) Admit that at page 150 of the Illinois Power Agency's 2024 LTRRPP, the Illinois Power Agency states that the Adjustable Block Program has led "to the energized or planned development of over 1,600 MW of new solar generation in Illinois thus far."

(h) Admit that at page 157 of the Illinois Power Agency's 2024 LTRRPP, the Illinois Power Agency states that the Adjustable Block Program has procured, to date since 2019, new solar projects' RECs totaling approximately 4.1 million annual RECs.

(i) Admit that according to pages 153 (including footnote 293) and 154 of the Illinois Power Agency's 2024 LTRRPP, the Illinois Power Agency has, in program years prior to the 2024-2025 program year, reserved 70% of Adjustable Block Program capacity for distributed and community solar projects in what it calls "Group B," covering Commonwealth Edison transmission territory.

(j) Admit that according to pages 168 and 177 of the Illinois Power Agency's 2024 LTRRPP, the "Public Schools" and "Equity Eligible Contractor" project categories of the Adjustable Block Program both include distributed solar and community solar projects.

(k) Admit that that according to page 158 of the Illinois Power Agency's 2024 LTRRPP, the Illinois Power Agency is reserving, in the Adjustable Block Program, 286 MW combined of community solar and distributed solar project capacity in the Commonwealth Edison transmission region for each of program years 2024-2025 and 2025-2026, plus a separate 391 MW combined of statewide distributed generation and community solar project capacity in each of those two program years.

(l) Admit that according to page 154 of the Illinois Power Agency's 2024 LTRRPP, the annual Adjustable Block Program total statewide capacity was set at 667 MW for program years prior to 2024-2025, and is increasing to 800 MW for program year 2024-2025, because, according to the Illinois Power Agency, "The solar market in Illinois is currently exhibiting immense growth, but the Program's categories [were] not appropriately sized to provide for stable growth within the Program."

Objections:

NIPSCO objects to this Request on the grounds and to the extent that this Request seeks documents or information that are not relevant to the subject matter of this proceeding and are therefore not reasonably calculated to lead to the discovery of admissible evidence.

NIPSCO further objects to subparts (c), (d), (e) – (l) of this Request on the separate and independent grounds and to the extent that this Request seeks publicly available information.

Response:

Subject to and without waiver of the foregoing general and specific objections, NIPSCO is providing the following response:

As noted in NIPSCO's response to CAC Request 23-001, the key findings summarized in slides 7-12 of Confidential Attachment 7-D and those used to support the major conclusions from the Flexible Resource Analysis offered in NIPSCO Witness Augustine's testimony were based on the NIPSCO zonal analysis, which evaluated the frequency, magnitude, and duration of NIPSCO's exposure to the market. The additional system level analysis referred to in CAC Request 23-001 included a broader market-level review, including assumptions for the PJM-ComEd zone in the year 2030.

(a) The market models used for the analysis were consistent with those used to develop market scenarios for NIPSCO's 2021 IRP. As such, PJM's load forecast from 2020 was used for the ComEd Zone. The report can be downloaded here: https://www.pjm.com/-/media/planning/res-adeq/load-forecast/previous-load-forecast-reports.ashx.

(b) As noted in NIPSCO's response to subpart (a) of this request, PJM's load forecast from 2020 was used for the Distributed Solar Adjustment. The relevant Distributed Solar Adjustment can be found on p. 56 of the 2020 load forecast report referenced in NIPSCO's response to subpart (a).

(c) See objections. The document speaks for itself.

(d) The scope and meaning of Illinois law is not relevant. Please see objections.

(e) through (l) See objections. The document speaks for itself.

CAC Request 28-001:

(a) At page 11, lines 9-11 of his rebuttal testimony (NIPSCO Ex. 7-R), Mr. Augustine states that "For modeling purposes, in order to ensure an 'apples-to-apples' comparison with other potential resource options, only the direct costs of the project were included in my analysis."

i. Please confirm that this means that Mr. Augustine's cost modeling as described on page 39 of this direct testimony (NIPSCO Ex. 7) did not include the $83,638,000 of indirect costs contained in NIPSCO Attachment 5-A. If "only the direct costs" (and, by implication, indirect) costs refer to some other amount, identify that amount and the document in which it is located.

ii. In Mr. Augustine's experience, what indirect costs are typically needed for other technology types including wind, solar, and battery storage? Please provide any documents that support your response.

(b) At page 27, lines 3-4 of his rebuttal testimony, Mr. Augustine states that aeroderivative turbines have "faster ramping" than battery storage. Please provide all the documents, with pinpoint citations, that support your position.

Objections:

Response:

(a)

i. Mr. Augustine's direct testimony on page 39 noted that "Based on bids received in the 2022 RFP, the thermal peaker resource incorporated in the preferred portfolio from the 2023 portfolio analysis had an assumed all-in direct capital cost of $1,440/kW." This value of $1,440/kW was used in the 2023 portfolio analysis presented in Mr. Augustine's direct testimony. In addition, on pages 39-40, Mr. Augustine's direct testimony compared this modeling assumption to the direct cost estimate of the CT Project and confirmed consistency, while noting that, "The direct cost estimate, inclusive of AFUDC, for the CT Project is currently estimated to be $560,053,449, which is $1,400/kW for approximately 400 MW." The capital costs used for the new gas peaker capacity in the 2023 portfolio analysis were detailed in CAC Request 3-015 Confidential Attachment A. The capital cost assumptions for new technology additions were

documented in the "Portfolio Inputs -->" tabs. Note that these were presented in 2021$/kW, with the "Inflation" tab providing inflation factors for nominal costs.

ii. As noted in Mr. Augustine's rebuttal testimony at p. 11, "indirect costs are generally ancillary to the core project components and incorporate overheads and other internal allocations." Overheads associated with labor and administrative costs not occurring at the specific project site may be necessary for any resource type, including wind, solar, and battery storage.

(b) This is an inaccurate representation of Mr. Augustine's statement. In referencing CAC Witness Sommer's evaluation of the CT Project relative to battery storage additions, Mr. Augustine's statement at page 27 argues that Witness Sommer should not have relied solely on an ancillary services analysis of frame combustion turbines relative to battery storage when NIPSCO's CT Project includes both frame combustion turbines and aeroderivative turbines. The full context of Mr. Augustine's statement at page 27 from lines 1-4 stated that Witness Sommer's "comparisons with gas peaking technology are based only on the frame combustion turbine technology evaluated in NIPSCO's 2021 IRP without consideration for potential additional value associated with faster ramping and more flexible aeroderivative turbines." Thus, Mr. Augustine's statement noted that aeroderivative turbines are faster ramping *than frame combustion turbines* and did not indicate that aeroderivative turbines are faster ramping than battery storage. In fact, Mr. Augustine acknowledged that "Witness Sommer reasonably points to the potential for greater ancillary services value for battery storage resources" on p. 26 of his direct testimony and would acknowledge that battery storage resources have such potential value as a result of flexibility and fast ramping attributes.

Cause No. 45947
Northern Indiana Public Service Company LLC's
Objections and Responses to
Citizens Action Coalition of Indiana, Inc.'s Thirty-Second Set of Data Requests

CAC Request 32-001:
Re: NIPSCO response to data request CAC 28.01 NIPSCO's response to CAC 28.01(a)(ii) states: "As noted in Mr. Augustine's rebuttal testimony at p. 11, 'indirect costs are generally ancillary to the core project components and incorporate overheads and other internal allocations.' Overheads associated with labor and administrative costs not occurring at the specific project site may be necessary for any resource type, including wind, solar, and battery storage." Please provide specific examples, including all supporting documents, of any indirect costs that Mr. Augustine has not previously included in any prior modeling on NIPSCO's behalf.
Objections:
Response:
In other prior modeling done on NIPSCO's behalf, including the 2018 and 2021 IRPs and the various CPCN applications referenced on p. 3 of Mr. Augustine's direct testimony, capital cost assumptions for new resources were developed from bids received by third-party developers of assets for sale to NIPSCO via Build Transfer Agreements. These capital cost assumptions included only direct costs, and Mr. Augustine's modeling analyses did not include additional indirect cost adders associated with NIPSCO overhead costs and other internal allocations, such as those documented by NIPSCO Witness Baacke in his rebuttal testimony on pages 22 and 23.

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. 202-26-46
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	)))))	Order No. 202-26-47

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

Exhibit 20
IURC Schahfer Gas Plant Order

STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF NORTHERN INDIANA PUBLIC SERVICE COMPANY LLC FOR (1) ISSUANCE OF A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY ("CPCN") PURSUANT TO IND. CODE CH. 8-1-8.5 TO CONSTRUCT AN APPROXIMATELY 400 MEGAWATT NATURAL GAS COMBUSTION TURBINE ("CT") PEAKING PLANT ("CT PROJECT"); (2) APPROVAL OF THE CT PROJECT AS A CLEAN ENERGY PROJECT AND AUTHORIZATION FOR FINANCIAL INCENTIVES INCLUDING TIMELY COST RECOVERY THROUGH CONSTRUCTION WORK IN PROGRESS RATEMAKING UNDER IND. CODE CH. 8-1-8.8; (3) AUTHORITY TO RECOVER COSTS INCURRED IN CONNECTION WITH THE CT PROJECT; (4) APPROVAL OF THE BEST ESTIMATE OF COSTS OF CONSTRUCTION ASSOCIATED WITH THE CT PROJECT; (5) AUTHORITY TO IMPLEMENT A GENERATION COST TRACKER MECHANISM ("GCT MECHANISM"); (6) APPROVAL OF CHANGES TO NIPSCO'S ELECTRIC SERVICE TARIFF RELATING TO THE PROPOSED GCT MECHANISM; (7) APPROVAL OF SPECIFIC RATEMAKING AND ACCOUNTING TREATMENT FOR THE CT PROJECT; AND (8) ONGOING REVIEW OF THE CT PROJECT, ALL PURSUANT TO IND. CODE CH. 8-1-8.5 AND 8-1-8.8, AND IND. CODE §§ 8-1-2-0.6 AND 8-1-2-23.	**CAUSE NO. 45947** **APPROVED:**

ORDER OF THE COMMISSION

Presiding Officers:
James F. Huston, Chairman
Kristin E. Kresge, Administrative Law Judge

On September 12, 2023, Northern Indiana Public Service Company LLC ("Petitioner" or "NIPSCO") filed its Verified Petition with the Indiana Utility Regulatory Commission ("Commission") seeking, among other relief, a certificate of public convenience and necessity ("CPCN") to construct an approximately 400 megawatt ("MW") natural gas combustion turbine ("CT") peaking plant ("CT Project") pursuant to Ind. Code ch. 8-1-8.5, and associated ratemaking and accounting treatment for the CT Project pursuant to Ind. Code ch. 8-1-8.8.[1]

[1] On August 11, 2023, NIPSCO provided its notice of intent to file an application for a CPCN in accordance with the Commission's General Administrative Order 2023-03.

Also on September 12, 2023, Petitioner filed the testimony and attachments of the following (all of whom are employees of Petitioner except as otherwise noted): Alison M. Becker, Manager of Regulatory Policy (Petitioner's Exhibit 1); David T. Walter, Vice President of Power Delivery (Petitioner's Exhibit 2); David Austin, Director of Transmission (Petitioner's Exhibit 3); Steven Warren, Senior Manager, Sargent & Lundy ("S&L") (Petitioner's Exhibit 4); Greg Baacke, Senior Director of Major Projects (Petitioner's Exhibit 5); Karl E. Stanley, Vice President of Supply & Optimization for NiSource Inc. (Petitioner's Exhibit 6);[2] Patrick N. Augustine, Vice President of Charles River Associates' Energy Practice, Charles River Associates ("CRA") (Petitioner's Exhibit 7); and Kevin J. Blissmer, Manager of Regulatory, NiSource Corporate Services Company ("NCSC") (Petitioner's Exhibit 8).

Petitions to intervene were filed by the Citizens Action Coalition of Indiana, Inc. ("CAC"); NIPSCO Industrial Group ("IG"); United Steel, Paper and Forestry, Rubber, Manufacturing, Energy, Allied Industrial and Service Workers International Union AFL-CIO/CLC and its Locals 12775 and 13796 ("USW"); and Primary Energy Recycling Holdings LLC ("Primary Energy"), all of which were granted.

On December 18, 2023, Petitioner filed an Agreed Modification to Procedural Schedule, which was granted by docket entry dated January 25, 2024.

On January 16, 2024, Petitioner filed the supplemental testimony and attachments of Ms. Becker (Petitioner's Exhibit 1-S), Mr. Walter (Petitioner's Exhibit 2-S), Mr. Baacke (Petitioner's Exhibit 5-S), Mr. Stanley (Petitioner's Exhibit 6-S), Mr. Augustine (Petitioners Exhibit 7-S), and Mr. Blissmer (Petitioner's Exhibit 8-S). The supplemental testimony reflected a one-year delay of the in-service date of the proposed CT Project.

On February 9, 2024, Petitioner filed an Agreed Modification to Procedural Schedule, which was granted by docket entry dated February 20, 2024.

A public field hearing was held in LaPorte, Indiana on March 14, 2024, during which members of the public presented testimony related to the relief sought in this Cause.

On April 16, 2024, the Indiana Office of Utility Consumer Counselor ("OUCC") filed the testimony and attachments of its witnesses, all of whom are employees of the OUCC's Electric Division: Cynthia M. Armstrong, Assistant Director (Public's Exhibit 1); John W. Hanks, Utility Analyst (Public's Exhibit 2); Roopali Sanka, Utility Analyst (Public's Exhibit 3); Gregory L. Krieger, Utility Analyst (Public's Exhibit 4); and Brittany L. Baker, Utility Analyst (Public's Exhibit 5). Also on that date, intervenors filed the testimony and attachments of their witnesses, including the following: Michael P. Gorman, Managing Principal, Brubaker and Associates, Inc. (IG Exhibit 1); Anna Sommer, Principal, Energy Futures Group (CAC's Exhibit 1); Robert G. James, Managing Director, Lumen Project Management Consultants (CAC's Exhibit 2); and Benjamin Inskeep, Program Director of CAC (CAC's Exhibit 3). USW did not file testimony. Primary Energy intervened after the deadline for intervenor testimony; therefore, Primary Energy

[2] Petitioner originally prefiled the Verified Direct Testimony of Andrew S. Campbell. NIPSCO filed a Notice of Substitution of Witness on January 16, 2024.

was precluded from filing testimony.

The OUCC also filed written consumer comments on April 19, 2024 (Public's Exhibit 6).

On May 21, 2024, NIPSCO filed the rebuttal testimony and attachments of Ms. Becker (Petitioner's Exhibit 1-R),[3] Mr. Warren (Petitioner's Exhibit 4-R), Mr. Baacke (Petitioner's Exhibit 5-R), Mr. Stanley (Petitioner's Exhibit 6-R), Mr. Augustine (Petitioner's Exhibit 7-R), Mr. Blissmer (Petitioner's Exhibit 8-R), and Stephen Holcomb, Director of Environmental Policy & Sustainability, NCSC, (Petitioner's Exhibit 9-R).

On June 17, 2024, NIPSCO filed revisions to reflect the marking of various confidential information in its case-in-chief, supplemental direct testimony, and rebuttal testimony from confidential to highly confidential.

On July 8, 2024, the Presiding Officers issued a docket entry question, to which NIPSCO responded on July 8, 2024.

The evidentiary hearing in this matter commenced on July 11, 2024, at 9:30 a.m. in Room 222 of the PNC Center, 101 W. Washington Street, Indianapolis, Indiana, at which time evidence was offered by NIPSCO, the OUCC, CAC, and IG without objection. Among the evidence offered at the hearing were certain stipulations between Petitioner and various intervenors with respect to certain facts and admissibility of specific exhibits, all of which were prefiled before the evidentiary hearing.

Based upon the applicable law and the evidence of record, the Commission finds:

1. Notice and Commission Jurisdiction. Due, legal, and timely notice of the public field hearing and evidentiary hearing in this Cause was given and published as required by law. NIPSCO is a "public utility" as defined in Ind. Code § 8-1-2-1(a) and Ind. Code § 8-1-8.5-1, an "energy utility" as defined in Ind. Code § 8-1-8.4-3, and an "eligible business" as defined in Ind. Code § 8-1-8.8-6. Pursuant to Ind. Code chs. 8-1-8.4 and 8-1-8.5, Petitioner may seek Commission approval of the CPCN requested in this Cause. Under applicable law, the Commission has jurisdiction over Petitioner and the relief sought by Petitioner in this Cause.

2. Petitioner's Characteristics. NIPSCO is a public utility with its principal office and place of business at 801 East 86th Avenue, Merrillville, Indiana. NIPSCO provides electric utility service to the public in all or part of Benton, Carroll, DeKalb, Elkhart, Fulton, Jasper, Kosciusko, LaGrange, Lake, LaPorte, Marshall, Newton, Noble, Porter, Pulaski, Saint Joseph, Starke, Steuben, Warren and White Counties in northern Indiana.

NIPSCO owns, operates, manages, and controls electric generating, transmission and distribution plant and equipment and related facilities, which are used and useful in the production, transmission, distribution and furnishing of electric energy, heat, light and power to the public.

[3] Petitioner originally prefiled the Verified Rebuttal Testimony of Robert C. Sears. NIPSCO filed a Notice of Substitution of Witness on May 29, 2024.

3. Relief Requested. In this Cause, NIPSCO requests the Commission (1) issue a CPCN pursuant to Ind. Code ch. 8-1-8.5 to construct the CT Project; (2) approve the CT Project as a clean energy project and authorize financial incentives, including timely cost recovery through construction work in progress ("CWIP") ratemaking under Ind. Code Ch. 8-1-8.8; (3) authorize recovery of costs incurred in connection with the CT Project; (4) approve the best estimate of costs of construction associated with the CT Project; (5) authorize implementation of a Generation Cost Tracker ("GCT") Mechanism; (6) approve changes to NIPSCO's Electric Service Tariff relating to the proposed GCT Mechanism; (7) approve specific ratemaking and accounting treatment for the CT Project; and (8) approve ongoing review of the CT Project, all pursuant to Ind. Code ch. 8-1-8.5 and 8-1-8.8, and Ind. Code §§ 8-1-2-0.6 and 8-1-2-23.

4. The Parties' Evidence.[4]

A. Petitioner's 2021 IRP and 2023 Portfolio Analysis. Mr. Augustine provided an overview of NIPSCO's resource planning process and reviewed the conclusions from the last several years, particularly its most recent the Integrated Resource Plan ("IRP") submitted November 15, 2021 (the "2021 IRP"). He also reviewed major market developments since the 2021 IRP and summarized the portfolio analysis that CRA and NIPSCO performed in 2023 based on these major market developments (the "2023 portfolio analysis"). Mr. Augustine stated the CT Project is consistent with the Short-Term Action Plan identified in the 2021 IRP and supported by additional analyses NIPSCO has performed.

Mr. Augustine testified the operational and cost characteristics of the CT Project are fully consistent with the assumptions for new peaking thermal resources used in the 2023 portfolio analysis, which developed a preferred portfolio with between 400 MW and 442 MW of new nameplate thermal peaking capacity additions in the near-term. He stated NIPSCO's Flexible Resource Analysis concluded that increasing the amount of long-duration dispatchable capacity above the 300 MW identified in NIPSCO's 2021 IRP will contribute to risk mitigation for customers, and the 2023 portfolio analysis demonstrated NIPSCO can achieve cost savings for customers relative to the 2021 IRP's preferred portfolio by pivoting towards a larger-sized, cost-effective thermal resource as compared to expensive storage additions.

Mr. Augustine testified that overall, the addition of the CT Project to NIPSCO's portfolio is fully supported by and consistent with the conclusions of the Flexible Resource Analysis, the 2023 portfolio analysis, and the flexibility embedded in the short-term action plan from NIPSCO's 2021 IRP.

In his supplemental testimony, Mr. Augustine presented updated information from Midcontinent Independent System Operator ("MISO") related to planning reserve margin requirements ("PRMR"), capacity accreditation, and NIPSCO's supply and demand balance. He explained that while the 2021 IRP and the 2023 portfolio analysis both incorporated the assumption that new gas peaking capacity would be in service in 2026, NIPSCO's 2021 IRP explicitly called for the procurement of short-term capacity as needed from the MISO market, and

[4] Unless otherwise noted, the summary below reflects updated information included in NIPSCO's supplemental testimony and attachments of Ms. Becker (Petitioner's Exhibit 1-S), Mr. Walter (Petitioner's Exhibit 2-S), Mr. Baacke (Petitioner's Exhibit 5-S), Mr. Stanley (Petitioner's Exhibit 6-S), Mr. Augustine (Petitioners Exhibit 7-S), and Mr. Blissmer (Petitioner's Exhibit 8-S) filed January 16, 2024.

the 2023 portfolio analysis included an expectation that short-term capacity purchase opportunities would be pursued through 2027. Therefore, a 2027 in-service date for the CT Project, accommodated by capacity market purchases to meet reserve margin requirements, remains consistent with NIPSCO's most recent resource planning conclusions. Mr. Augustine testified the change in in-service date does not impact the operational and cost characteristics of the CT Project, which were shown to be fully consistent with the assumptions for new peaking thermal resources used in the 2023 portfolio analysis. He explained that based on the latest information from MISO regarding PRMR and capacity accreditation, the capacity purchase requirements through 2027 should be manageable and in line with historical levels, although NIPSCO will need to continue to actively monitor market conditions and evolving MISO rules as part of its ongoing capacity procurement plans. Mr. Augustine concluded the addition of the CT Project to NIPSCO's portfolio continues to be fully supported by and consistent with the conclusions of NIPSCO's Flexible Resource Analysis, the 2023 portfolio analysis, and the flexibility embedded in the short-term action plan from NIPSCO's 2021 IRP.

OUCC witness Mr. Hanks had concerns that NIPSCO's incorporation of misaligned results of an all-source request for proposal ("RFP") – together with an RFP that solicited bids for a particular technology configuration – inflates the cost of the thermal peaking resource incorporated into the 2023 portfolio analysis, which could potentially to distort the results of the resource selection process used within the IRP. Mr. Hanks argued the costs used for new generic peaking capacity in the 2023 portfolio analysis were artificially inflated, making NIPSCO's estimate for the CT Project appear more reasonable, and that NIPSCO inappropriately combined the results of an all-source RFP and a technology and configuration restricted RFP. Mr. Hanks also suggested that the $1,400/kW metric for capital costs for the CT Project used in NIPSCO's analysis understated the costs of the project by excluding $83.68 million in indirect costs. Mr. Hanks testified that the $/kW metric is more accurately reflected as $1,609/kW.

CAC witness Ms. Sommer noted the Flexible Resource Analysis did not quantify the cost of NIPSCO's potential market price risk exposure or compare the costs of resources that could reduce the net load exposure. Ms. Sommer argued there was no evaluation of an alternative approach to mitigate potential risks identified in the Flexible Resource Analysis, such as a portfolio with battery storage and more demand response. Ms. Sommer suggested that under the proposed direct loss of load ("DLOL") structure, battery resources will have stronger capacity accreditation than natural gas peaker resources. Ms. Sommer stated NIPSCO's capacity calculations overstate both summer and winter accreditation for the proposed natural gas peaker resource, while understating the value of battery storage resources. Ms. Sommer performed a levelized cost analysis to compare the costs of NIPSCO's proposed CT Project with potential battery storage capacity at the existing Schahfer site to suggest that new battery additions would be lower cost than NIPSCO's proposed CT Project.

IG witness Mr. Gorman stated that, instead of relying on a complete, or updated IRP, NIPSCO based the request for a 400 MW CT on a Flexible Resource Study. Mr. Gorman suggested NIPSCO failed to consider the introduction of MISO's seasonal resource construct and that NIPSCO has not fully evaluated its resource obligations at various times of the year. Mr. Gorman testified that NIPSCO failed to account for the expected changes in Rate 531 Tier 1 demand and has therefore failed to "right size" the CT Project.

In rebuttal, Mr. Augustine testified that while the OUCC and intervenors directly and implicitly challenge the size and technology composition of NIPSCO's proposed CT Project, no one testified NIPSCO does not need this type of new capacity, which was identified in its 2021 IRP and in the subsequent analyses. Mr. Augustine addressed the OUCC and intervenors' testimonies in relation to the 2023 portfolio analysis, the Flexible Resource Analysis, NIPSCO's future supply-demand balance, and additional analysis and considerations that were introduced.

Mr. Gorman testified that instead of relying on a complete, or updated IRP, NIPSCO based the request for a 400 MW CT on a Flexible Resource Study, Mr. Augustine responded that Mr. Gorman provided an incomplete characterization of the analysis NIPSCO performed in support of its requested CPCN. He stated that the Flexible Resource Analysis was only one component of the further diligence NIPSCO performed on the preferred portfolio from its 2021 IRP. He said that although the conclusions from the Flexible Resource Analysis supported and contributed to NIPSCO's sizing decision for the CT Project, NIPSCO also performed a 2023 portfolio analysis to assess the performance of alternative portfolio options against updated market conditions and the latest available information.

Mr. Gorman suggested NIPSCO failed to consider the introduction of MISO's seasonal resource construct and that NIPSCO has not fully evaluated its resource obligations at various times of the year. Mr. Augustine responded that although MISO's seasonal construct was implemented after the submission of NIPSCO's 2021 IRP, NIPSCO anticipated this change and evaluated seasonal peak load forecasts and seasonal capacity ratings for resource options in its 2021 IRP to develop portfolios based on capacity requirements for both the summer and winter seasons. He also stated NIPSCO's 2023 portfolio analysis incorporated updated seasonal reserve margin targets and seasonal accredited capacity levels that were published after the Federal Energy Regulatory Commission ("FERC") approved MISO's seasonal construct. He testified higher winter reserve margin targets contributed to higher requirements for dispatchable thermal or storage capacity additions in the 2023 portfolio analysis relative to the levels evaluated in NIPSCO's 2021 IRP, which was directly accounted for in the portfolio construction.

Ms. Sommer's testified she did not perform independent modeling in part due to concerns the portfolios that were examined included projects that NIPSCO has canceled. Mr. Augustine responded that while some of the portfolios did include projects that had been canceled, preferred Portfolio 3 was explicitly developed to incorporate the risk of project cancellations, specifically the potential loss of four out of ten or 700 MW of solar and 30 MW of storage of NIPSCO's current solar and solar plus storage projects. He stated that consistent with these assumptions, NIPSCO has since filed termination notices for these four projects and has used the 2023 portfolio analysis to support replacement of these projects with incremental wind and solar capacity,[5] as explicitly modeled in preferred Portfolio 3 and approved by the Commission.

Mr. Hanks argues the costs used for new peaking capacity in the 2023 portfolio analysis were artificially inflated and that NIPSCO inappropriately combined the results of an all-source RFP and a technology and configuration restricted RFP. Mr. Augustine responded that Mr. Hanks

[5] NIPSCO filed a CPCN for the 200 MW Appleseed solar project and the 200 MW Templeton wind project in Cause No. 45887 (approved September 13, 2023) and a CPCN for the 200 MW Carpenter wind project in Cause No. 45908 (approved October 18, 2023).

appeared to misunderstand what NIPSCO requested in the two RFPs that were issued in 2022, as well as the types of bids that were received. As a result, he argued the comparisons Mr. Hanks attempted to make are inappropriate. He stated that contrary to Mr. Hanks' claims, NIPSCO's Schahfer Development or Engineering, Procurement, and Construction ("EPC") RFP was not technology and configuration restricted. He explained while NIPSCO did require a dispatchable, blackstart-capable resource at the Schahfer site with several other performance criteria, no restrictions were placed on the technology and configurations that could be proposed by bidders, and bids into this RFP were used by NIPSCO and CRA to arrive at the $1,440/kW direct capital cost number presented in his direct testimony and in the 2023 portfolio analysis.

Mr. Augustine testified Mr. Hanks' criticism that the capital costs for the CT Project used in his analysis understate the costs of the project by excluding indirect costs is misplaced. He stated that for modeling purposes, to ensure an "apples-to-apples" comparison with other potential resource options, only the direct costs of the project were included in his analysis, which is both commonplace and appropriate. He explained that while NIPSCO includes indirect costs in the overall project cost estimate, these costs are generally ancillary to the core project components and incorporate overheads and other internal allocations. He testified that including these company-specific indirect costs in weighing resource options would serve only to skew the results and the purpose of the portfolio and revenue requirement modeling analysis he performed is primarily to compare costs of resource options; therefore, excluding indirect costs provides a direct cost comparison, which is a more meaningful and reasonable approach.

Ms. Sommer testified the Flexible Resource Analysis did not quantify the cost of NIPSCO's potential market price risk exposure or compare the costs of resources that could reduce the net load exposure. Mr. Augustine responded that the Flexible Resource Analysis was designed to assess the energy adequacy and flexibility characteristics of NIPSCO's preferred portfolio from the 2021 IRP and to analyze and characterize the potential for market exposure risk. He stated that as Ms. Sommer correctly points out, the Flexible Resource Analysis was not an economic assessment, but a means of assessing the magnitude, frequency, and duration of market exposure risk and the overall ability for NIPSCO's portfolio to be positioned to respond to evolving market conditions and bring its fair share of reliability attributes to the system in the face of uncertain MISO rules. Mr. Augustine testified although NIPSCO did not quantify the costs of market exposure risk in the Flexible Resource Analysis, the key outcomes are supportive of the fact that additions of long-duration dispatchable capacity like the CT Project will improve reliability and reduce market exposure cost risk for customers, which Ms. Sommer did not challenge.

Mr. Augustine testified Ms. Sommer's argument that there was no evaluation of an alternative approach to mitigate potential risks identified in the Flexible Resource Analysis is inaccurate. He stated that in addition to the resource attribute needs identified in the Flexible Resource Analysis, NIPSCO's 2023 portfolio analysis specifically evaluated a portfolio with additional battery storage resources and no new thermal peaking capacity to assess the economic tradeoffs relative to the portfolio that contained the new peaker, and that it concluded the portfolio with new peaking capacity was lower cost for customers. He noted NIPSCO's 2021 IRP did the same and concluded that the portfolio with new peaker capacity performed similarly or better on cost-based metrics than a portfolio relying only on storage and best on the reliability metrics. Mr. Augustine testified NIPSCO has performed multiple evaluations to assess alternative approaches and arrive at its preferred portfolio with the CT Project.

Mr. Gorman testified NIPSCO has failed to account for the expected changes in Rate 531 Tier 1 demand and has therefore failed to "right size" the CT Project. Mr. Augustine explained NIPSCO's 2021 IRP did evaluate a scenario with the exact reduction in Tier 1 demand commitments suggested by Mr. Gorman. Mr. Augustine noted NIPSCO incorporated the potential for additional industrial load migration to the new industrial rate service structure. The scenario incorporated a reduction of firm industrial load in Rate 831 down to 70 MW. He further explained that NIPSCO's 2021 IRP shows its preferred portfolio performed well under these assumptions.

Ms. Sommer proposes battery storage and demand response resources be deployed because these resources can be added quicker than the CT project can be built. Mr. Augustine testified while development and deployment timelines will vary by resource, NIPSCO's preferred portfolio from its 2021 IRP and 2023 portfolio analysis contemplated new battery storage and demand side management resource additions by 2028, and he expects additional capacity additions will be identified as NIPSCO continues its ongoing resource planning activities in 2024 and beyond. He explained the resource is expected to be in service by the end of 2027, in advance of the 2028/29 planning year when the MISO rules are due to change, and the resource offers a firm, dispatchable addition to NIPSCO's portfolio that will help fill the existing and emerging capacity gap.

Mr. Augustine disagreed with Ms. Sommer's suggestion that battery resources will have stronger capacity accreditation than natural gas peaker resources and her statement that NIPSCO's capacity calculations overstate summer and winter accreditation for the proposed natural gas peaker resource, while understating the value of battery storage resources. He testified future capacity accreditations under D-LOL remain too uncertain to definitively make such a claim, and the forward-looking information published by MISO is supportive of the assumptions used in NIPSCO's 2023 portfolio analysis, which included stable accreditation for gas resources and declining accreditations for four-hour battery storage resources over time.

In response to Ms. Sommer's levelized cost analysis, which compared the costs of NIPSCO's proposed CT Project with potential battery storage capacity at the existing Schahfer site and suggested that new battery additions would be lower cost than NIPSCO's proposed CT Project, Mr. Augustine opined that while levelized cost analysis can be a useful way of comparing resource options, Ms. Sommer's calculations were not performed correctly, nor do they replace the 2023 portfolio analysis performed by NIPSCO and CRA, which aimed to provide a more holistic comparison of NIPSCO's preferred portfolio concept versus one that relies primarily on new storage additions. Mr. Augustine described a significant calculation error and several limitations relative to the 2023 portfolio analysis in Ms. Sommer's analysis.

Mr. Hanks' and Ms. Sommer's oppose NIPSCO's application in part because of the cost of the aeroderivative turbine component, and Mr. Hanks' argues NIPSCO has not established that the benefits of aeroderivative units are worth the higher cost relative to industrial frame units. Mr. Augustine testified NIPSCO's 2021 IRP and Flexible Resource Analysis are supportive of resource additions with the attributes of the aeroderivative turbines. He explained in NIPSCO's 2021 IRP, the ancillary services valuation and the reliability assessment highlighted the need for certain attributes like fast ramping capability, particularly as the MISO markets evolve, and that NIPSCO's Flexible Resource Analysis identified growing 3-hour and 10-minute ramping requirements by 2030.

B. <u>CT Project</u>. In her direct testimony, Ms. Becker explained how NIPSCO supported, through sufficient evidence, the statutory requirements for the issuance of a CPCN, including financial incentives, under Ind. Code §§ 8-1-8.5-4, 8-1-8.5-5, and 8-1-8.8-11. She sponsored Attachment 1-A showing each element of Ind. Code §§ 8-1-8.5-4, 8-1-8.5-5, and ch. 8-1-8.8 and identified the NIPSCO witness with supporting testimony.

Ms. Becker explained how NIPSCO supported the requirements set out in Ind. Code § 8-1-2-0.6. She sponsored Attachment 1-C showing each of the Five Pillars, which includes reliability, affordability, resiliency, stability, and environmental sustainability. and identified the NIPSCO witness with supporting testimony. She also explained how NIPSCO has addressed the guidelines for additional evidence to be provided pursuant to IURC GAO 2022-01. She sponsored Attachment 1-D providing the required information as it pertains to NIPSCO's request for approval under Ind. Code chs. 8-1-8.5 and 8-1-8.8 in this Cause. She also sponsored Attachment 1-G, which is the Affidavit of Andy Witmeier, Director of Resource Utilization for MISO, providing a qualitative assessment regarding the new generation, including NIPSCO's request to MISO. In her supplemental testimony, Ms. Becker described NIPSCO's follow-up contact with MISO considering the shift in the in-service date.

Ms. Becker testified NIPSCO followed the guidelines applicable to applications for a CPCN established in the Commission's General Administrative Order 2023-03 ("GAO 2023-03"). She sponsored NIPSCO's notice of its intent to file an application for a CPCN as Attachment 1-E. She also testified NIPSCO met to discuss its filing with the Commission on May 8, 2023, the OUCC on May 24, 2023, and CAC on July 12, 2023. She sponsored an index of issues and identification of the witness(es) addressing each of the issues as Attachment 1-F.

As it relates to the statutory requirements set out in Ind. Code § 8-1-8.5-4, Ms. Becker addressed the requirement to consider conservation and load management. She testified that based on her experience with NIPSCO's energy efficiency ("EE") initiatives, NIPSCO could not derive sufficient energy savings from EE to replace Schahfer. She said NIPSCO is committed to the development of demand response programs for all customer groups but concluded that demand response would not eliminate the need for the CT Project, and, based on how such plants are constructed, would likely not reduce the size of the project.

Mr. Walter described NIPSCO's current generation fleet and explained the ultimate portfolio NIPSCO currently expects to have in place to serve its customers after its coal-fired generating units are retired over the next five years. He opined the CT Project is a clean energy project as that term is defined in Ind. Code § 8-1-8.8-2. He addressed how the proposed construction of the CT Project relates to the Five Pillars outlined in Ind. Code § 8-1-2-0.6.

Mr. Austin explained NIPSCO's gas distribution system as it relates to the CT Project, the quick-start, fast-ramping, and other important capabilities of the CT Project at the Schahfer site, and the CT Project's contribution to NIPSCO's system reliability.

Mr. Warren sponsored the Engineering Study prepared by S&L, which set forth the Class 3 cost estimate for NIPSCO's proposed simple cycle gas turbine project that was used by NIPSCO to develop its best estimate of the costs of the proposed CT Project. He presented information regarding the engineering work completed by S&L in support of NIPSCO's request for approval

of a new peaker power plant to be located at the Schahfer site.

Mr. Baacke explained the CT Project, including key specifications and characteristics, the approach to configuration selection and the contracting strategy for the CT Project. He also provided the project schedule and the best estimate of costs of construction. He explained the CT Project is planned to be approximately 400 MW, consisting of one larger industrial frame unit with three smaller aeroderivative or similarly sized industrial frame units (dependent on the results of the CT original equipment manufacturer ("OEM") bid event). Finally, he discussed how the CT Project satisfies Ind. Code § 8-1-8.5-5(e).

Mr. Stanley discussed: (1) how the CT Project will interconnect into the MISO market through the replacement generation interconnection process, (2) NIPSCO's need for capacity from a peaking unit, and (3) how NIPSCO will procure gas supply for the Project at the lowest reasonable cost. Finally, he discussed how the CT Project is consistent with the resource alternatives that must be evaluated under Ind. Code § 8-1-8.4-4.

i. Best Estimate. In his direct testimony, Mr. Baacke stated NIPSCO employed S&L to help develop a scope of work to obtain preliminary quotes for major equipment during the engineering study phase to support the cost estimate shown in Appendix 20 of the Engineering Study (Highly Confidential Attachment 4-A). He stated S&L then supported NIPSCO by drafting technical specifications for the EPC RFP. He said the cost estimated by S&L was compared to the costs for gas-fired projects bid into the EPC RFP. He explained that after NIPSCO elected to move forward with the self-build option to capture cost savings and other advantages, S&L developed technical specifications to support a competitive bid event for the procurement of turbines for the CT Project that occurred in June 2023 (the "turbine equipment RFP") with bids received August 7, 2023. He indicated that similar competitive bid events are planned to be completed for other major equipment as well as major construction contracts.

Mr. Baacke testified the EPC RFP was issued in Fall 2022, seeking bids for projects between 370 MW to 450 MW. He stated technical specifications for the EPC RFP were drafted because of the work previously performed in collaboration with S&L during the engineering study phase. He testified bidders were requested to provide proposals with a combination of industrial frame and aeroderivative combustion turbines meeting specific performance criteria. He explained the performance criteria included desired machine sizing, cold start timing, ramp rates, minimum emission compliant loads, emission limits, remote start and operational capabilities, and other reliability capabilities.

Mr. Baacke described the results of the proposals were received from three bidders. One bid did not meet the performance criteria of the technical specifications and provided less than five pages of information and was not evaluated for further consideration. A second bid provided a proposal that consisted of ten refurbished aeroderivative turbines which did not align with the RFP criteria or the performance criteria of the technical specifications. A third bid aligned with the technical specifications however, the proposal price was $100 million more than the self-build option costs of construction. He testified NIPSCO ultimately chose the self-build option, which is in the best interest of NIPSCO and its customers.

Mr. Baacke described the procurement and bid process NIPSCO is using to purchase equipment for the CT Project. He stated NIPSCO plans to utilize a multi-prime contracting strategy for the CT Project, which is different from an engineering, procurement, and construction contracting strategy in which a single entity would be utilized to perform all engineering, procurement, construction, and start up and commissioning activities to complete the project. He stated NIPSCO plans to hold competitive bid events whenever practical for major equipment such as generator step-up transformers, unit auxiliary transformers, generator circuit breakers, switchgear, and other associated auxiliary equipment and to procure smaller equipment and materials through preferred suppliers that were identified through prior strategic sourcing events.

Mr. Baacke testified NIPSCO's multi-prime contracting strategy applies to construction on the CT Project as well. He stated NIPSCO plans to develop bid packages to competitively bid the three major scopes of construction in 2024: (1) site preparation/civil construction contract, (2) general works construction contract, and (3) an electrical installation contract. Mr. Baacke testified that under this planned construction and bid process, NIPSCO will have allowed third parties to submit firm and binding bids for the construction of the CT Project on NIPSCO's behalf that meet all the technical, commercial and other specifications so as to enable ownership of the CT Project to vest with NIPSCO not later than the date the facility becomes commercially available.

Mr. Baacke testified the best estimate of the total cost of construction for the CT Project is $641,223,000, which includes indirect costs but excludes allowance for funds used during construction ("AFUDC"). He explained NIPSCO will accrue AFUDC associated with the CT Project costs based upon the amounts at the time such costs or charges are incurred. He stated that based upon estimates of AFUDC at the time of this filing, the total estimated cost, including AFUDC of $2,468,449, is $643,691,449.[6] Mr. Baacke stated the cost estimate was developed with the support of S&L. Mr. Baacke sponsored the best estimate of cost summary in Attachment 5-A as well as a more detailed estimate of cost summary in Confidential Attachment 5-B.

In his supplemental direct testimony, Mr. Baacke discussed supply chain challenges that affected the project schedule and how NIPSCO's election to self-build utilizing a multi-prime contracting strategy has allowed NIPSCO to pivot in the face of these challenges without a presently anticipated impact to the best estimate. He sponsored an updated CT Project schedule and best estimate of costs of construction.

Mr. Baacke stated NIPSCO's originally estimated in-service date for end of year 2026 was with the understanding the CT Project must be in service no-later-than end of year 2027 due to planned retirements in 2028. He explained this timeline included some flexibility as is typical for significant construction projects, especially given supply chain challenges are more commonplace since COVID-19. He stated that based on the expectation that the combustion turbines and generation step-up transformers would be the longest lead time equipment, NIPSCO went out for bid on these components before filing its request for a CPCN and noted NIPSCO was still evaluating the information received from the bid events, including ongoing conversations with suppliers. Mr. Baacke testified NIPSCO's election to self-build with a multi-prime contracting

[6] NIPSCO Witness Mr. Blissmer testified that if NIPSCO's proposed CWIP ratemaking is approved, AFUDC is projected to be very limited, and would include only actual AFUDC accrued to date and through the effective date of the GCT Mechanism, expected to be in October 2024.

strategy was beneficial in the face of these supply chain challenges because it allowed NIPSCO to pivot without a presently anticipated impact to the best estimate. He noted other contracting structures, such as with an EPC contractor, would likely have required the execution of a change order to shift the in-service date to end of year 2027 and increased costs as a result. Additionally, he stated NIPSCO was able to secure a favorable procurement timeframe for generator step-up transformers due to its vendor relationship.

In his supplemental testimony, Mr. Baacke testified the best estimate of the total cost of construction for the CT Project remains at $641,223,000, which includes indirect costs but excludes AFUDC. He explained NIPSCO will accrue AFUDC associated with the CT Project costs based upon the amounts at the time such costs or charges are incurred. Based upon estimates of AFUDC at the time of this supplemental filing, Mr. Baacke testified the total estimated cost, including AFUDC of $1,531,039, is $642,754,039.

OUCC witness Ms. Armstrong recommended costs associated with certain pollution control technology be removed from the CT Project best estimate. Ms. Armstrong stated NIPSCO can seek approval of any future pollution control costs as federally mandated costs under the Federal Mandate Statute at Ind. Code ch. 8-1-8.4. Ms. Armstrong stated the OUCC does not consider NIPSCO's request for the CT Project, as currently proposed, to be affordable.

OUCC witness Mr. Hanks stated NIPSCO's best estimate potentially double counts indirect costs. Mr. Hanks stated NIPSCO did not justify a 5% escalation factor and recommended its proposed escalation be reduced to 3% to match its electric Transmission, Distribution, and Storage System Improvement Charge ("TDSIC") Plan. Mr. Hanks compared the cost of NIPSCO's proposed CT Project to average technology costs from the U.S. Energy Information Administration's ("EIA") Annual Energy Outlook of 2023 and to the cost of CEI South's CTs.

OUCC witness Mr. Krieger stated the OUCC is concerned with NIPSCO's estimated owner's costs. He believed NIPSCO's application of a simple nine percent is not supported or justified for a complex project. Mr. Krieger believed the owner's costs would be significantly less when an EPC contractor is hired.

IG witness Mr. Gorman stated NIPSCO's cost estimate should be rejected because it is not based on firm pricing because of competitive bids received from contractors, but rather on preliminary market analysis of the expected costs.

CAC witness Ms. Sommer argued for prejudgment of the prudency of certain actions and prospective disallowance of costs. Ms. Sommer argues for a cost cap on project costs. Ms. Sommer recommended denial of NIPSCO's request based on the cost of the aeroderivative turbines. Ms. Sommer recommended that costs to serve customers in order to accommodate a delay in the online date of the CT Project be disallowed including but not limited to capacity and energy costs.

Mr. Baacke disagreed with CAC witness Mr. James' assertion that a self-build approach is not in customers' best interests and adds significant risk to the Project cost. He testified NIPSCO has experience with both EPC and multi-prime contracts and provided some of NIPSCO's history of successfully executing on large and complex projects below.

In response to several witnesses claims that entering an EPC contract can mitigate cost risk and multi-prime contracting may translate into additional ratepayer costs, Mr. Baacke testified that while EPC contracts can provide some benefits, the parties fail to appreciate that, to create certainty, an EPC contractor is paid for risks that could potentially be avoided, mitigated, or not occur at all. Mr. Baacke testified that both contracting strategies have benefits and the potential for increased costs; however, for the CT Project, and after careful consideration, NIPSCO determined the multi-prime contracting strategy offers a greater potential for savings on the overall cost of the project, especially when managed effectively and scoped accurately.

OUCC witness Mr. Krieger and CAC witness Mr. James claim NIPSCO does not have experience building gas-fired generation projects of this scale and are concerned NIPSCO lacks large project management experience. Mr. Baacke explained NIPSCO is leveraging engineering firms including S&L, construction contractors, and suppliers, including the original equipment manufacturer ("OEM"), who have completed comparable projects. He testified NIPSCO's Major Projects team has completed a number of projects of varying complexity, including several projects that are first of their kind or one-of-a-kind projects and at the time of completion, within the industry.

Mr. Baacke testified Mr. Krieger's review of the accuracy as a percentage of budget for each project that he has served a major role is not a fair and complete picture of his project management experience. This review only shows the project variances in absolute dollars, which ignores the variances on these projects have been both higher and lower than the original budgets. He stated that in relative dollars, NIPSCO's original budgets versus actual costs for the referenced projects shows that, on an overall original budget of $1.41 billion, projects that have been completed under Mr. Baacke's direction and supervision reflect a negative variance of approximately -2.4%. This data reflects NIPSCO's commitment to manage the construction of the CT Project such that the Project is executed on time and on budget.

Mr. Baacke clarified S&L's scope of work in the CT Project. He stated S&L has also been contracted by NIPSCO to complete the detailed design for the CT Project. He testified NIPSCO plans to contract with S&L to provide onsite support during construction, start up and testing to provide quality assurance and quality control during installation. Mr. Baacke testified the costs associated with these additional services is included in NIPSCO's best estimate.

Mr. Baacke sponsored Attachment 5-R-A and Confidential Attachment 5-R-B showing the best estimate of the total cost of construction for the CT Project remains at $641,223,000, which includes indirect costs but excludes AFUDC. He explained NIPSCO will accrue AFUDC associated with the CT Project costs based upon the amounts at the time such costs or charges are incurred and that based upon estimates of AFUDC at the time of this rebuttal filing, the total estimated cost, including AFUDC of $2,680,234, is $643,903,234.

Mr. Baacke emphasized NIPSCO's best estimate although reasonable, is still an estimate; customers will pay the actual costs of the CT Project. He testified that prices for practically all products and materials in the U.S. are increasing, including the key equipment needed to construct the CT Project; this is an undeniable macroeconomic fact, which is beyond NIPSCO's control. He testified NIPSCO ran a competitive RFP, engaged S&L to assist with engineering and cost estimation, chose a multi-prime contracting approach which was $100 million lower in cost than

any viable EPC option, and brought a reasonable, best estimate to the Commission to support a finding of best estimate of costs in this proceeding.

ii. Configuration and Competitive Procurement. Mr. Baacke testified the CT Project is expected to consist of one larger industrial frame unit with three smaller aeroderivative or similarly sized industrial frame units. He explained NIPSCO is targeting an F Class combustion turbine for the larger industrial frame turbine, which has been on the market for over 30 years and has a proven history of solid, reliable performance. General Electric's F Class combustion turbine has been upgraded to its 7FA.05 model with power output and heat rate values at ISO conditions of approximately 239 MWs and 8,871 btu/kWh (LHV) and shorter start times to as little as 11 minutes and ramp rates as high as 50 MWs per minute. Similar performance exists for Siemens Energy's SGT6-5000F combustion turbine. Larger industrial frame units typically have a lower capital cost per kilowatt to install, require fewer machines, and generally have longer intervals between maintenance when compared to aeroderivative turbines.

He explained NIPSCO is including three smaller aeroderivative or similarly sized industrial frame turbines in the CT Project. Aeroderivative turbines are typically more efficient, start faster and frequently, and fluctuate power generation faster to meet demand when compared to larger industrial frame turbines. These features, along with market import capabilities, allow a utility to install large volumes of renewable energy and still maintain the ability to reliably and efficiently serve a heavy industrial customer base, as well as commercial and residential load, when the intermittent renewable resources are not available for short or prolonged periods of time.

Mr. Baacke testified NIPSCO chose the preferred configuration to maximize benefits to NIPSCO and its customers. This preferred configuration was needed to conduct an RFP to seek proposals for the EPC RFP. NIPSCO and S&L developed a decision matrix to select the equipment configuration that would be used for purposes of the EPC RFP. This evaluation included performance criteria to align with the Flexible Resource Analysis, operational factors, costs, environmental factors, and schedule.

Mr. Baacke explained the benefits to constructing the CT Project on the Schahfer site. He stated NIPSCO already owns the property. He said constructing the CT Project on this site provides cost savings and advantages for NIPSCO, its customers, and the local economy.

As discussed by NIPSCO witness Mr. Stanley, NIPSCO holds interconnection rights at the Schahfer site related to Units 17 and 18 that will be retiring by the end of 2025. The MISO grid interconnection rights can be transferred from existing coal units to the CT for up to three years after retirement.

OUCC witness Mr. Hanks claims the EPC RFP prevented bidders from proposing less expensive all industrial frame configurations, Mr. Baacke testified EPC RFP bidders were not prevented from proposing all industrial frame configurations. He testified the technical specifications for the EPC RFP, which are over two hundred pages, were provided to the parties in discovery and shows that the EPC RFP asked bidders to select a combination of industrial frame and aeroderivative CTs and optionally, reciprocating internal combustion engines that could meet certain defined constraints, including (1) total net output between 370 MW and 450 MW; (2) maximum machine size of 275 MW; (3) at least one machine 150 MW or larger; (4) 10-minute

cold start capability for 150 MW or more; (5) 50 MW/minute minimum ramp rate for at least 150 MW of the Facility's machines; and (6) at least one machine with a minimum emission compliant load less than or equal to approximately 25 MW. He testified the defined constraints were assembled to provide potential bidders with enough information to know the type of project that would fit the needs identified by NIPSCO and CRA through the Flexible Resource Analysis, but freely allowed potential bidders to provide bids that would include one larger industrial frame machine and multiple smaller aeroderivative or industrial frame units.

Mr. Baacke noted that while Mr. Hanks claims NIPSCO "self-selected" its preferred configuration and required bidders to offer aeroderivative units, CAC witness Mr. James claims the quality of NIPSCO's EPC RFP was wanting insofar as it relies upon a project that needs more definition and planning. Mr. Baacke testified that while the OUCC and CAC appear to disagree on the appropriate level of detail needed in the RFP, NIPSCO's balanced approach falls reasonably between the two.

Mr. Baacke testified NIPSCO's internal EPC RFP bid evaluation scorecard and related documentation were provided in discovery and show NIPSCO properly vetted the EPC RFP bids. He stated given the EPC RFP bid results and NIPSCO's history with successful project execution, NIPSCO made the prudent decision to pursue a multi-prime contracting strategy.

OUCC witness Ms. Sanka's claims NIPSCO failed to evaluate the configuration with one large industrial frame and smaller industrial frame, similarly sized to the aeroderivative turbines, in the decision matrix of S&L's Engineering Study. Mr. Baacke testified this criticism is misplaced. He explained smaller industrial frame machines provide similar performance when compared to smaller aeroderivative machines; therefore, it was not necessary to perform a separate analysis for a large industrial frame with smaller industrial frame machines.

NIPSCO witnesses Mr. Augustine and Mr. Holcomb explain in their rebuttal testimony that the U.S. Environmental Protection Agency released greenhouse gas emission rules for the power sector on April 24, 2024, which lay out the best system of emission reduction standards for new natural gas-fired facilities based on their capacity factor. Mr. Holcomb explained that based on the expected operational characteristics of NIPSCO's proposed units, the overall CT Project will be able to operate within the standards of the rule. Furthermore, given their higher efficiencies, the aeroderivative turbines will be able to more easily achieve the 1,170 lb. CO2/MWh standard than the frame turbine, offering more flexibility and optionality for NIPSCO to operate the units at higher capacity factors should conditions within the MISO market make such operations beneficial for its customers.

OUCC witness Ms. Sanka claims that, base load plants come at a lower initial cost and have lower operations and maintenance costs compared to a peaker plant containing aeroderivative units, making them more financially viable. Therefore, in a 30-year lifespan, the cost-effectiveness of using a configurated base load plant outweighs the benefits of using a configuration containing aeroderivative technology for peaker plants. Mr. Augustine explained Ms. Sanka's framing of the cost-effectiveness evaluation is incomplete, particularly as resource planning questions become more complex.

5. Commission Discussion and Findings. Since the issuance of its 2021 IRP, NIPSCO has continued to evaluate and analyze its generation needs considering ongoing changes in market rules, supply chain, and other broader market changes. NIPSCO's most current analysis identifies a need for a gas-fired resource between 400 MW and 442 MW. Based on the needs associated with the retirement of most of NIPSCO's coal-fired generation by the end of 2025 and the addition of renewable resources, NIPSCO seeks to construct and operate the CT Project as a part of its overall, diverse portfolio of generation assets. Once operational, the facility will be a central part of NIPSCO's electric generating fleet, because it will provide key reliability attributes and additional capacity, particularly in the winter season.

NIPSCO's Flexible Resource Analysis concluded increasing the amount of long-duration dispatchable capacity above the 300 MW identified in NIPSCO's 2021 IRP will contribute to risk mitigation for customers, and the 2023 portfolio analysis demonstrated NIPSCO can achieve cost savings for customers relative to the 2021 IRP's preferred portfolio by pivoting towards a larger-sized thermal resource as compared to more expensive storage additions. The Flexible Resource Analysis identified potential reliability issues resulting from the relatively large share of planned renewable generation in NIPSCO's preferred portfolio and assessed flexibility needs on an inter-hour and intra-hour basis. The analysis also evaluated how NIPSCO's mix of resources is likely to perform in 2030 compared to 2021 and identified that the 10-minute ramp requirements are increasing by 150 MW. NIPSCO's EPC RFP specifications for the proposed CT Project included requirements of a 10-minute ramp cold start capability for 150 MW or more and a 50 MW/minute ramp rate for at least 150 MW. The OUCC agrees NIPSCO needs load-following generation. We conclude that the CT Project is an economical decision that will aid in reliability; therefore, the Commission grants the requested CPCN for the CT Project.

A. CPCN for CT Project Under Ind. Code § 8-1-8.5-5. Ind. Code § 8-1-8.5-2 states that a public utility must obtain a CPCN from the Commission prior to constructing, purchasing, or leasing a facility for the generation of electricity. Ind. Code § 8-1-8.5-5 sets forth the criteria for approving a utility-specific generation proposal. In granting a CPCN, the Commission must make findings on the best estimate of the project's cost based on the record, whether the proposal is consistent with our statewide analysis or a utility-specific proposal, and whether public convenience and necessity require the project. The Commission must also consider the items set forth in Ind. Code § 8-1-8.5-4. We address the required findings and review each factor in Ind. Code § 8-1-8.5-4 below.

i. Best Estimate of Costs. Under Ind. Code § 8-1-8.5-5(b)(1), a CPCN may be granted only if the Commission makes a finding "as to the best estimate of construction, purchase, or lease costs based on the evidence of record[.]"

Mr. Baacke explained the CT Project, including key specifications and characteristics, as well as NIPSCO's approach to configuration selection and contracting strategy. He provided the project schedule, the best estimate of costs of construction, and NIPSCO's request for ongoing review pursuant to Ind. Code § 8-1-8.5-6. He explained the CT Project is planned to be approximately 400 MW, consisting of one larger industrial frame unit with three smaller aeroderivative or similarly sized industrial frame units. Mr. Walter explained NIPSCO's cost estimate is the best estimate currently available and will be updated as the project proceeds, consistent with the Commission's requirements and NIPSCO's request for ongoing review.

Mr. Walter testified NIPSCO began with a competitive EPC RFP and engaged the assistance of Sargent and Lundy. Based on available information in the market and the bids received, NIPSCO determined the best path is to self-build the CT Project, leveraging the available interconnection rights from retiring generation at Schahfer. NIPSCO issued its turbine equipment RFP in June 2023 and executed an agreement with its turbine manufacturer on March 29, 2024 to reserve the selected equipment. Mr. Baacke's supplemental direct testimony described unexpected supply chain challenges impacting NIPSCO's ability to timely procure breakers and generator step-up transformers, and explained that this caused NIPSCO to shift the expected in-service date for the CT Project to year-end 2027. Despite this change, the best estimate of the total cost of construction did not change.

Mr. Blissmer testified NIPSCO is currently carrying significant preliminary, survey, and investigation costs on its books that it will record to the cost of owned generating resources, a portion of which will be applied to the new CT Project. These preliminary, survey, and investigation costs were not challenged by any party and are included in NIPSCO's best estimate of the cost of construction for the CT Project.

NIPSCO's best estimate of the total cost of construction (excluding AFUDC) for the CT Project is $641,223,000. NIPSCO confirmed its cost estimate in its supplemental testimony based on updated supply chain information. Mr. Blissmer explained NIPSCO removed escalation and reduced the amount of contingency associated with owner's costs and certain equipment. The total estimated cost of the CT Project, including estimated AFUDC of $2,680,234, is $643,903,234. This AFUDC estimate assumes NIPSCO's proposed forward looking GCT Mechanism is approved.

The following discussion details the challenges to NIPSCO's best estimate.

a. <u>Configuration of CT Project</u>. CAC witness Mr. James opined NIPSCO and S&L progressed through project initiation with less than adequate attention to current best practices for early project definition, namely a Front-End Engineering and Design ("FEED") study, and that NIPSCO's process to reach a final investment decision remains questionable. Based on the evidence presented, we find that NIPSCO and S&L's design and engineering process was thorough, consistent with industry standards, including the Association for the Advancement of Cost Engineering cost classification, and rigorous in evaluating three different configurations for the design of the CT Project. Mr. Warren explained FEED studies evaluate whether a project should move forward at each step or stage and is unnecessary because of the IRP process and S&L's Engineering Study. The process NIPSCO used to develop its CT Project is like processes we have seen used by other utilities for which we have approved CPCNs. While FEED studies have been used for other projects in Indiana, we have only seen them in connection with novel technologies, such as coal gasification or carbon capture. In designing and engineering the CT Project, NIPSCO leveraged S&L's extensive power industry expertise. S&L's Engineering Study provided NIPSCO with the level of information needed to determine the technology and configuration that best meet the simple cycle gas turbine requirements.

Based on the evidence of record, we find NIPSCO's CT Project was properly scoped, designed, and engineered and that NIPSCO and S&L's up-front design activities reasonably align with the intended purpose of CAC witness Mr. James' recommended design process. As such,

NIPSCO is not required to complete any further front-end engineering and design diligence.

The OUCC and CAC took issue with NIPSCO's EPC RFP. The OUCC asserts that NIPSCO's EPC RFP was too narrow. CAC witness Mr. James alleges that a lack of detail contributed to the poor response rate to the RFP. The OUCC and CAC both challenge the aeroderivative turbines due to their cost. OUCC witnesses Ms. Sanka and Mr. Hanks assert that operational characteristics of the aeroderivative units do not justify the higher overall expenditure when compared to a configuration comprised of only industrial frame turbines. CAC witness Ms. Sommer recommended denial of the CT Project due to the three aeroderivative turbines and suggested reducing the cost of the CT Project by replacing the aeroderivative turbines with a second industrial frame machine.

Three of the Five Pillars we are charged with evaluating in the context of a CPCN for new generation are reliability, resiliency, and stability. We observe that before us is a request for new generation that is specifically designed with load-following characteristics to support NIPSCO's evolving generation fleet. NIPSCO's 2021 IRP Short-Term Action Plan identified a need for a thermal peaking option to mitigate the energy adequacy and flexibility characteristics of the IRP's largely renewable, and therefore intermittent, preferred portfolio. NIPSCO conducted further diligence through its Flexible Resource Analysis, which evaluated the risks associated with times of resource unavailability and market purchase exposure. Informed by these analyses, in its EPC RFP, NIPSCO sought bids for projects between 370 MW and 450 MW with certain performance criteria. This analysis further refined the need by noting that there is a significant growth in the need for faster ramping resources. The analysis shows that 150 MW with a ramp rate of 10 minutes is needed by 2030. As such, the EPC RFP specification included, among other things, 10-minute cold start capability for 150 MW or more and 50 MW/minute minimum ramp rate for at least 150 MW of the facility's machines. NIPSCO witness Mr. Baacke pointed out the Engineering Study recognized that smaller industrial frame machines provide similar performance when compared to smaller aeroderivative machines, rendering a separate evaluation of an all-industrial frame configuration unnecessary. The technical specifications for NIPSCO's turbine equipment were appropriately driven by the key performance criteria identified in the Flexible Resource Analysis. The cost of the CT Project here is below the $1,440/kW in direct capital cost that was assumed in the 2023 portfolio analysis, which was based on the responses to NIPSCO's 2022 RFP.

The OUCC seeks to reduce the best estimate to remove the aeroderivative configuration. Mr. Krieger provides the reduction in cost as a range of $30-40 million; he does not provide the methodology to arrive at this amount. Ms. Sanka compared the cost of three aeroderivative units to the cost of a single larger frame unit using data pulled from Public Exhibit No. 3 Confidential Attachment RS-3, and her comparison produces a difference of $37.6 million. The single larger frame unit, which Ms. Sanka used for comparison, does not possess the same 10-minute cold start and ramp rates that the smaller industrial units or aeroderivative units. Ms. Sanka stated her objection is that NIPSCO did not evaluate a configuration with three smaller industrial frame units sized to match the aeroderivative units. However, the OUCC's proposed reduction is based upon a peaker unit that would not possess the start time and ramping rates that NIPSCO requires.

The OUCC's and CAC's evidence fails to counter the fact that aeroderivative turbines provide several attributes that complement NIPSCO's largely renewable portfolio, including fast start capability, the ability to start and stop multiple times per day without impacting maintenance

cycles, and high efficiency. The fast-ramping capability of the aeroderivative turbines provides functionality that will satisfy reliability needs within NIPSCO's service territory and the MISO footprint.

CAC witness Ms. Sommer testifies that, if certain MISO market reforms are implemented, NIPSCO will likely need more capacity starting in 2028, even if the proposed CT Project enters into service. It is this capacity potential that unlocks the unique customer benefit of the aeroderivative turbines. NIPSCO's rebuttal evidence establishes that the aeroderivative units provide NIPSCO with flexibility to qualify as an intermediate load unit and potentially operate at greater capacity factors than an industrial frame unit, while remaining compliant with the Rule's emissions limits. Absent adequate capacity, to manage resource adequacy, NIPSCO will have to purchase capacity on the market. It is this rationale that drives us to decline CAC's invitation to prejudge NIPSCO's proactive capacity purchases as described by NIPSCO witness Mr. Stanley.

OUCC witness Hanks' testimony raises general arguments about the cost of the CT Project, intimating that its cost per kilowatt should not exceed the cost of CEI South's CTs approved in Cause No. 45564 or the average cost per kilowatt located in the EIA 2023 Energy Outlook. We reject comparison between the CT Project and the average cost per kW figures in the EIA's 2023 Outlook, as EIA's own Administrator plainly stated that the Outlook is not intended to provide estimates or predictions. Mr. Hanks did not attempt to reconcile the many factors that could impact – positively or negatively – the installed cost per kW of various technologies. As to Cause No. 45564, we note that NIPSCO and CEI South operate under different generation constraints and customer composition. CEI South's project was designed three years ago within a different market. There is substantial record evidence describing the current high demand for critical equipment and contractors within the power industry. CEI South's CTs were designed before the escalation in demand for CTs occurred, which has created a more competitive construction market. The OUCC did not include the estimated $27.3 million in annual expense CEI South will incur to receive gas supply from a new 24-mile pipeline. The estimated cost of NIPSCO's gas interconnection (which is under $1.5 million) was discussed by NIPSCO witness Mr. Austin in his direct testimony and was included within the best estimate for the CT Project.

The technical specifications for the combustion turbine equipment were sufficiently defined, appropriately developed to address the needs of NIPSCO's renewable portfolio without limiting bidders to a specific kind of technology, and consistent with industry standards. We find NIPSCO's preferred configuration of one industrial frame turbine and three aeroderivative turbines is appropriately informed by the results of the bid event and will provide critical, stable, load-following generation. Finally, given the substantial evidence on the important, load-following attributes the aeroderivative turbines provide, we find the aeroderivative turbines are cost-justified and appropriately included in NIPSCO's preferred configuration for the CT Project.

b. <u>Contracting Strategy for CT Project</u>. The OUCC and the CAC challenged NIPSCO's decision to self-build the CT Project, as opposed to utilizing an EPC contractor. OUCC witness Mr. Krieger testified the OUCC is concerned with NIPSCO's self-build project management approach including its ability to properly manage construction, as well as its ability to manage and mitigate financial challenges. CAC witness Mr. James testified NIPSCO lacks experience constructing power plants and NIPSCO's contracting strategy is similar to one of the strategies Duke Energy Indiana attempted to employ during the construction of the

Edwardsport Integrated Gasification Combined Cycle project.

The record contains evidence regarding the results of NIPSCO's EPC RFP bid. Mr. Baacke's direct testimony stated NIPSCO received three EPC bids – one that was $100 million more than the self-build option, and two bids that were inconsistent with technical specifications. NIPSCO conducted extensive due diligence to evaluate each bid received to determine whether its technical specifications could be met at a reasonable cost, and ultimately chose to self-build the CT Project.

The OUCC and CAC express general concerns that, without an EPC contractor, the risk of ratepayer-borne cost overruns from the construction of the CT Project has increased. This criticism ignores the fact that NIPSCO solicited bids from the EPC market and received only one bid that would have met its technical requirements, which we found were appropriately defined and reasonably driven by system needs, at a price that is $100 million more than NIPSCO's best estimate of construction in this Cause. While an EPC contract is a valid way to execute a generation project, it is not a requirement to receive a CPCN in Indiana nor is it a guarantee against project cost overruns.

OUCC witness Mr. Krieger and CAC witnesses Ms. Sommer and Mr. James claimed NIPSCO does not have experience building gas-fired generation projects of this scale and are concerned NIPSCO lacks large project management experience. The evidence in this Cause establishes that NIPSCO conducted diligence in both resource planning decisions and project design, engineering, and contracting. The evidence in this proceeding demonstrates that NIPSCO's team has sufficient experience to handle this project.

This is NIPSCO's first time overseeing construction of a new gas-fired generation project. The CT Project has undergone extensive upfront design and engineering. It will be built on an existing NIPSCO-owned site. No land acquisition will be needed and there is only the need for a 1,500-foot lateral pipeline to access NIPSCO's natural gas system. NIPSCO has prudently extended its runway to complete the CT Project through year-end 2027 and given the substantial reservation payment to the turbine equipment manufacturer, the evidence supports NIPSCO has a project plan in place enabling the CT Project to be constructed on time and on budget within reasonable constraints. The multi-prime strategy selected by NIPSCO produces a best estimate of costs that is $100 million less than the cost that would be produced under the only responsive EPC bid NIPSCO received.

CAC and NIPSCO agree demand for EPC contractors in the power industry is high. NIPSCO witness Mr. Warren testified this high level of demand has shifted EPC contractors' interest to larger projects that maximize their potential profits. We do not believe it would be prudent to require NIPSCO to pursue an EPC contract that could exceed the cost of NIPSCO's multi-prime contracting strategy by $100 million.

S&L has experience executing gas-fired generation projects. Based upon the evidence of record, we conclude NIPSCO selected a competent partner in S&L, and that this collaboration will continue throughout construction and start-up/commissioning of the CTs.

NIPSCO has availed itself of ongoing review of the CT Project pursuant to Ind. Code § 8-1-8.5-6. In issuing a CPCN, we approve the best estimate of costs. To the extent the utility incurs costs more than the best estimate that we approve, the utility will have the burden of demonstrating that the additional cost is reasonable. If other parties believe that the increase should be rejected, they retain the right to take such a position. The CAC and OUCC's fears over risk and escalation are all appropriately mitigated through ongoing review, which can serve to protect ratepayers from unnecessary costs and project mismanagement.

NIPSCO contends choosing the self-build option will decrease costs by $100 million. Due to the expected cost savings, the Commission approves NIPSCO choosing this option. The Commission emphasizes the importance of the estimated $100 million savings being realized. These savings shall be reflected in the updated cost estimates in the semi-annual filings discussed later in this order.

c. Best Estimate Cost Components. OUCC witnesses Mr. Hanks and Mr. Krieger challenged NIPSCO's indirect costs, alleging they lacked support and were potentially double counted in S&L's cost estimate. However, Mr. Baacke's rebuttal testimony explained that the confidential version of the best estimate shows one line item for "Indirects," which represents NIPSCO's indirect costs while S&L's indirect costs are reflected as "Misc Inside the Fence," "Misc Electric Interconnect," "Misc Gas Interconnect," and "Misc Water Interconnect" in NIPSCO's best estimate. He stated NIPSCO explained each cost category and how they were estimated in response to CAC discovery and that the itemization of S&L's indirect costs in Section 10.2.3 of the Engineering Study confirms these costs do not duplicate NIPSCO's indirect costs. We agree. NIPSCO's internal indirect costs are capital overhead and stores, freight, and handling while S&L's indirect costs are associated with construction management and start-up and commissioning support. These line items are separate and distinct, and we find that NIPSCO's evidence supports concluding no indirect costs were double counted.

Mr. Hanks challenged NIPSCO's proposed 5% escalation factor and recommended it be reduced to 3%, as was approved in NIPSCO's electric TDSIC Plan. We are convinced by NIPSCO's evidence that a 5% escalation factor is appropriate. NIPSCO's supplemental testimony describes the global supply chain uncertainty, which prompted the shift in the CT Project's in-service date to end of year 2027. Mr. Baacke's rebuttal testimony provides specific detail on the 70% cost increase for 345kV breakers, which NIPSCO has witnessed in a few months in late 2023. Given that NIPSCO's electric TDSIC Plan was approved before the COVID-19 pandemic and its resulting supply chain issues, we conclude reducing NIPSCO's escalation factor to what was approved in that proceeding is not appropriate. Accordingly, we find NIPSCO's 5% escalation factor is reasonable and approved.

Mr. Krieger opposed NIPSCO's 9% estimate for owner's costs, arguing it is too simple for a high-cost capital project and that owner's costs would be lower under an EPC contract. Based on updated cost information from executed contracts with certain suppliers, NIPSCO updated the 9% owner's cost estimate to $41,210,000 in Mr. Baacke's rebuttal testimony. We addressed the parties' concern with NIPSCO's contracting strategy above and found NIPSCO's self-build, multi-prime approach will reduce the cost of the CT Project for the benefit of customers. Based on the evidence provided, we conclude NIPSCO's estimated owner's costs are informed by executed contracts and are approved.

d. Pollution Control Technology. OUCC Witness Armstrong testified the Selective Catalytic Reduction units are not needed for the CT Project to meet current environmental requirements and that if they are required in the future, NIPSCO could seek recovery of any future pollution control costs through the Federally Mandated Cost Management ("FMCA") statute. Mr. Holcomb's rebuttal testimony confirmed the CT Project will comply with the final Greenhouse Gas ("GHG") Rule; therefore, NIPSCO updated the best estimate to reflect removal of the Selective Catalytic Reduction units. We approve this revision to the scope of the CT Project and recognize that as federal environmental regulations may change, Indiana law offers options utilities may consider for recovering compliance costs, including the FMCA statute.

e. Conclusion on Best Estimate. We find NIPSCO has submitted sufficient evidence supporting its best estimate on the cost to construct the CT Project, which is driven by its preferred configuration and contracting strategy along with its projected $100 million savings due to utilizing the self-build option. NIPSCO's best estimate is based on a detailed engineering analysis, information from turbine manufacturers and contractor bid events from which capital costs, operating costs, performance characteristics, and construction schedules were determined. The best estimate reasonably reflects the current market, industry trends, and the potential cost impact of project risk and factors beyond NIPSCO's control. The CT Project is reasonably designed to manage industry and economic challenges while facilitating the capacity and energy resources required by NIPSCO to meet its customers' ongoing need for electricity. Based on the evidence, we find that $641,223,000 (excluding AFUDC) is the best estimate of the cost of construction of the CT Project.

ii. Consistency with Petitioner's 2021 and 2023 Portfolio Analysis. Ind. Code § 8-1-8.5-5(b)(2) provides that a CPCN shall be granted only if the Commission has made a finding that either:

> (A) the construction, purchase, or lease will be consistent with the commission's analysis (or such part of the analysis as may then be developed, if any) for expansion of electric generating capacity; or
>
> (B) the construction, purchase, or lease is consistent with a utility specific proposal submitted under [Ind. Code § 8-1-8.5-3(e)(1)] and approved under subsection (d).

Ind. Code § 8-1-8.5-3(e)(1) provides that a public utility may submit "a current or updated integrated resource plan as part of a utility specific proposal as to the future needs for electricity to serve the people of the state or the area served by the utility[.]" Mr. Augustine sponsored Petitioner's 2021 IRP as Petitioner's Highly Confidential Attachment 7-B and a summary of the key inputs and outputs associated with the 2023 portfolio analysis as Petitioner's Highly Confidential Attachment 7-C. Thus, we find NIPSCO has submitted a utility-specific proposal under Ind. Code § 8-1-8.5-3(e)(1).

The record demonstrates that the CT Project is consistent with the Short-Term Action Plan identified in Petitioner's 2021 IRP.

We note at the outset that we have recently expressed support of NIPSCO's 2021 IRP process, stating that "NIPSCO's 2021 IRP process, which occurred in concert with the 2022 RFP, was robust and well developed, ultimately resulting in the Short-Term Action Plan on which the

proposed Appleseed and Templeton PPAs are based." *N. Ind. Pub. Serv. Co.*, Cause No. 45926 (IURC Nov. 22, 2023) at 20 citing *N. Ind. Pub. Serv. Co.*, Cause No. 45587 (IURC Sept. 13, 2023). IRPs are created at a point in time and use modeled scenarios to show how resources perform over a variety of alternative future conditions. NIPSCO performed the 2021 IRP analysis and has appropriately responded to changes in the electric industry and the broader market and now seeks approval of generation additions based on the same foundation we have repeatedly found was sufficient. NIPSCO's 2021 IRP did not rely on a single set of assumptions that could later be invalidated by evolving market conditions. Since the 2021 IRP was issued, the timeline for implementation of the Short-Term Action Plan identified in the 2021 IRP has been three years (2022–2024), and NIPSCO's proposed CT Project is consistent with this timeline.

NIPSCO's 2021 IRP performed a retirement analysis to assess different retirement dates for different elements of the existing fleet. The 2021 IRP continued to affirm earlier retirement of coal capacity resulted in lower costs for customers. The 2021 IRP concluded new additions should be predominantly renewable resources, supplemented by a diverse mix of other technologies, including an uprate to NIPSCO's existing Sugar Creek combined cycle, new thermal peaking capacity, new energy storage capacity, new distributed energy resources, and additional demand side management programs. These conclusions were informed by review of all metrics on NIPSCO's integrated scorecard, including cost to customer, scenario and stochastic-based cost risk, carbon emissions, resource optionality, impacts on the local economy, and a comprehensive quantitative reliability assessment, which included analysis of ancillary services, blackstart requirements, dispatchability, and other technical reliability parameters. Given evolving MISO market rules related to intermittent resource accreditation, seasonal reserve margin planning, and other reliability planning considerations, relative to NIPSCO's 2018 IRP, the 2021 IRP concluded that additional dispatchable resources like thermal peaking capacity and storage were necessary additions to the portfolio.

NIPSCO conducted an additional technical reliability assessment to ensure the non-economic implications of various portfolio options, particularly regarding compliance with MISO market rules and North American Electric Reliability Corporation ("NERC") standards, were accounted for. As part of the assessment, eight reliability criteria were identified, and different portfolio options were evaluated against each of them. The reliability criteria included blackstart capability, energy adequacy, dispatchability and automatic generation control, operational flexibility and frequency support, volt-ampere reactive ("VAR") support or reactive power, geographic location relative to load, predictability and firmness of supply, and short-circuit strength sufficiency. NIPSCO's analysis concluded portfolios that included new thermal resources (natural gas-fired peakers and combined cycles, including those with hydrogen enablement) scored better on the reliability criteria than portfolios reliant only on new renewables and storage and no new incremental thermal capacity.

The record demonstrates the 2023 portfolio analysis accounted for NIPSCO's ongoing resource planning and other market conditions and developments that have occurred since the 2021 IRP was completed, including, among other things, updated pricing from NIPSCO's 2022 RFP, changes to the MISO resource adequacy construct, commodity pricing updates, and changes to federal law.

We have previously concluded that, "[i]nherently, integrated resource plans are performed at a point in time and use modeled scenarios to show how resources perform over a variety of alternative future conditions." *Northern Indiana Public Service Co., LLC*, Cause No. 45462, at 62 (May 5, 2021). The Commission has previously found that utilities should utilize "an array of best practices, including basing model inputs on its 2022 RFP, which allow[s] for an informed forecast at that time." *Southern Indiana Gas & Elec. Co.*, Cause No. 45501, at 29 (Oct. 27, 2021). The evidence demonstrates that NIPSCO has utilized best practices for an informed forecast.

IG witness Mr. Gorman recommended denial of NIPSCO's requested CPCN based on his belief that NIPSCO had not updated its 2021 IRP and had not analyzed several material developments since the completion of the 2021 IRP including: (1) the introduction of MISO's seasonal resource adequacy construct; (2) the enactment of the Inflation Reduction Act; (3) the presence of supply chain constraints, tariff uncertainty and inflationary cost pressure; and (4) additional RFPs with Charles River Associates to assess the latest market data for new resources. His claims are contradicted by evidence in the record. Mr. Augustine explained Mr. Gorman's testimony does not acknowledge or reference NIPSCO's 2023 portfolio analysis. As discussed, this analysis used the preferred portfolio themes from NIPSCO's 2021 IRP and updated their composition according to the latest market information, which resulted in additional wind capacity, less solar capacity, and more thermal peaking or storage capacity. Mr. Augustine's direct testimony discussed how NIPSCO anticipated MISO's seasonal construct in its 2021 IRP, which evaluated seasonal peak load forecasts and seasonal capacity ratings for resource options to develop portfolios based on capacity requirements for both the summer and winter seasons, and that its 2023 portfolio analysis incorporated updated seasonal reserve margin targets and seasonal accredited capacity levels that were published after FERC approved MISO's seasonal construct. NIPSCO's 2023 portfolio analysis has been relied upon to support approval of other generation projects.[7] As such, we find NIPSCO's resource planning and selection process to select its Short Term Action Plan, including the CT Project, is consistent with its 2021 IRP, and is therefore consistent with NIPSCO's utility-specific proposal under Ind. Code § 8-1-8.5-3(e)(1).

Mr. Gorman testified NIPSCO's evaluation of the proposed CT Project was deficient because it failed to consider planned changes to its future Rate 531 Tier 1 load and instead relied on its future supply demand positions based on its 2021 IRP without modifying any assumptions associated with expected reductions in Rate 531 Tier 1 load. Mr. Augustine's rebuttal testimony outlined three reasons why this criticism is invalid: (1) the Rate 831/531 Modification Agreement approved in Cause No. 45772 recognizes Tier 1 commitments may decline over time, but that no firm declarations of commitment reductions have been made by any Rate 531 customer, and it is not certain that all seven current Rate 531 customers would elect to reduce their demand to the tariff minimum as outlined by Mr. Gorman; (2) even if the proposed CT Project is approved and all seven Rate 531 customers reduce their commitments over a multi-year period through 2033 as outlined in the Rate 831/531 Modification Agreement, NIPSCO will likely still require additional capacity purchases or other capacity additions to meet current seasonal MISO planning requirements as well as potential future changes associated with resource accreditation rules at MISO to meet potential future demand growth; and (3) NIPSCO's 2021 IRP did evaluate a

[7] Cause No. 45926 (Gibson Solar), Cause No. 45887 (Appleseed Solar and Templeton Wind), Cause No. 45908 (Carpenter Wind), and in NIPSCO requests for changes in cost and ownership structure for various solar and solar plus storage projects in Cause Nos. 45936, 46028, and 46032, the latter two of which are still pending.

scenario with the exact reduction in Tier 1 demand commitments suggested by Mr. Gorman, and NIPSCO's preferred portfolio was found to perform well under such assumptions. Mr. Augustine explained NIPSCO was not required to "hard code" into its demand forecast a reduction that may not come to fruition; instead, as it did, NIPSCO's 2021 IRP and 2023 portfolio analysis are based on probabilistic modeling which included numerous load scenarios, including the scenario Mr. Gorman advocated for.

The evidence of record demonstrates the CT Project is consistent with and supported by the 2021 IRP and 2023 portfolio analysis. The 2021 IRP concluded flexible thermal generation resources, additional solar capacity and a diverse mix of other resources including storage, emerging technologies, and market purchases/capacity were necessary additions to the portfolio for it to meet current and future load and reserve margin requirements. Moreover, as further discussed below, the CT Project is consistent with the Flexible Resource Analysis which found that flexible, dispatchable capacity resources are needed to complement NIPSCO's largely renewable portfolio – particularly resources that can meet specific ramp requirements.

We conclude NIPSCO's resource planning process is appropriate given the amount of uncertainty around timing and actual amounts of load reduction. Ms. Becker testified the Rate 531 customers may reduce their load, but they have not done so yet and NIPSCO cannot assume that they will. Furthermore, and as noted by CAC witness Ms. Sommer, NIPSCO likely will need an additional 400+ MW of capacity beginning in 2028, which could be partially addressed by further reductions of Rate 531 Tier 1 load. Based on the evidence, we find NIPSCO's 2021 IRP, as supplemented and supported by the 2023 portfolio analysis, is a valid basis for approval of the CT Project, and the CT Project is consistent with the 2021 IRP.

iii. Consistency with Commission's Energy Analysis. Ind. Code § 8-1-8.5-3(a) provides that "the commission shall develop, publicize, and keep current an analysis of the long-range needs for expansion facilities for generation of electricity." The Commission issued its 2018 Report on the Statewide Analysis of Future Resource Requirements for Electricity ("2018 Statewide Analysis") in October 2018.

The data and analysis underlying NIPSCO's proposal and the state of the overall electric industry have continued to develop since the 2018 Statewide Analysis. Mr. Walter's direct testimony noted that multiple IRPs have been completed since the most recent report. The record in this Cause demonstrates that MISO, MISO's Independent Market Monitor ("IMM"), and the NERC support the need for flexible, dispatchable resources to pair with increasing levels of renewable generation to ensure reliability.

Based on the evidence of record, we find NIPSCO's proposal to build the CT Project, which offers a flexible, dispatchable resource that will support NIPSCO's predominantly renewable generating portfolio and that of other Indiana electric utilities, is consistent with the Commission's energy analysis, including the 2018 Statewide Analysis and developments since that report was issued.

iv. Public Convenience and Necessity. Under Ind. Code § 8-1-8.5-5(b)(3), before granting a CPCN, the Commission must make "a finding that the public convenience and necessity require or will require the construction, purchase, or lease of the

facility[.]" "The public convenience and necessity criterion is common in public utility matters and generally concerns whether the proposal is fitted or suited to the public need." Indiana Michigan Power Co., Cause No. 44871, at 30 (March 26, 2018). NIPSCO contends that its preferred configuration of one industrial frame unit and three aeroderivative units is reasonable and appropriate given NIPSCO's fast-ramping, load-following needs. Based on the evidence of record, we agree, as explained further below.

Our determination of public convenience and necessity under Ind. Code § 8-1-8.5-5(b)(3) is also guided by Ind. Code § 8-1-8.5-4(b), which provides the factors that the Commission must consider in acting on any petition for the construction, purchase, or lease of any facility for the generation of electricity.[8]

a. Ind. Code § 8-1-8.5-4(b)(1). Mr. Stanley described NIPSCO's involvement in MISO, an independent system operator, and testified this portion of the statutory language predates the formation of MISO. He stated the statutory concepts of "interchange of power" and "pooling of facilities" would seem to be addressed through use of an independent system operator. Mr. Stanley explained that while the current MISO market effectively utilizes the existing capacity resources to meet the overall energy requirements of the region, including NIPSCO, NIPSCO's membership in MISO does not eliminate its need to meet the capacity requirements of its customers, including adding new capacity resources to address potential load growth and reliable load-following generation. As to the remaining elements of Subsection (b)(1), Mr. Stanley testified NIPSCO has conducted several all-source RFPs, and joint ownership and power purchases were not excluded by those RFPs to the extent other electric utilities were interested. Mr. Augustine testified NIPSCO's all-source RFPs, its IRP, and the 2023 portfolio analysis allowed for and considered numerous resource options, including solar, solar plus storage, storage, thermal, wind, hydrogen, and a range of structures that may include both energy and capacity.

The evidence of record shows NIPSCO's participation in MISO was specifically considered in the development of its Short Term Action Plan, including the proposed CT Project, which supports the conclusion that Petitioner's current and potential options for entering arrangements with other utilities related to the interchange of power, pooling of facilities, purchase of power, and joint ownership of facilities have been evaluated, and Ind. Code § 8-1-8.5-4(b)(1) has been satisfied.

b. Ind Code § 8-1-8.5-4(b)(2). While some of the parties challenged the size and technology composition of NIPSCO's proposed CT Project, which we addressed above, no party proposed an alternative to the CT Project or stated NIPSCO does not have a need for the type of new capacity that was identified in its 2021 IRP and in the subsequent analyses undertaken after the submission of the IRP. The OUCC "agrees that load-following replacement generation capacity is necessary to reliably serve NIPSCO's customers" and "recognizes that NIPSCO's IRP and updated analysis shows additional replacement capacity for retiring generation is needed to preserve reliability, resiliency, and stability." Pub. Ex. 1 at 3. The

[8] No party identified an applicable federal phaseout mandate for purposes of Ind. Code § 8-1-8.5-4(b)(3). Ind. Code § 8-1-8.5-4(b)(4) is discussed later in the order.

CAC points out if recent proposed MISO market reforms are implemented, "NIPSCO likely needs more capacity starting in 2028" even when assuming the proposed CT Project enters into service. CAC Ex. 1 at 21, 24. These statements affirm NIPSCO's requirement for incremental capacity, and the evidence of record supports NIPSCO's CT Project as a required addition that will help fill this need.

Regarding maintaining essential reliability services, NERC, in its 2022 Long-Term Reliability Assessment, states: "[r]etiring conventional generation is being replaced with large amounts of wind and solar; … As replacement resources are interconnected, these new resources should have the capability to support voltage, frequency, and dispatchability." *Id*. at 18-19.

Regarding "refurbishment of existing facilities," NIPSCO witness Mr. Augustine testified NIPSCO evaluated the potential conversion of one or two units at its Schahfer plant in its 2018 IRP and found conversion cost more than the alternatives. Section 4.10.5 of NIPSCO's 2018 IRP noted the analysis "showed that converting one unit would cost at least $230 million more than retirement and replacement with economically optimized selections from the 2022 RFP results and replacing both units would cost customers at least $540 million more." Mr. Augustine explained a refueled Unit 17 or 18 would not be a viable alternative to the CT Project as it would not possess the fast-start/quick-ramping and reliability characteristics of a peaking facility that the 2021 IRP and the 2023 portfolio analysis called for. No party challenged this evidence.

As to cogeneration, NIPSCO witness Mr. Stanley testified renewable generation has been a significant component of NIPSCO's generation portfolio transition since its 2018 IRP, and the CT Project is intended to complement the substantial renewable fleet NIPSCO has added and continues to add. He explained cogeneration, if available, would have been responsive to the 2022 RFPs. NIPSCO witness Ms. Becker testified on conservation and load management by describing NIPSCO's three demand response programs and its robust portfolio of demand side management/energy efficiency programs targeted towards residential, commercial and industrial customers. She explained NIPSCO carried out a lengthy analysis of demand side management/energy efficiency resources included in its IRP process, including completing a market potential study to determine the achievable amount of savings. Ms. Becker explained NIPSCO's 2021 IRP modeling demonstrates energy efficiency will be an important part of NIPSCO's resource options in the future and will be particularly important to help mitigate against the need to build new generation to serve incremental load; however, NIPSCO's modeling indicates the most economical option for customers over the long term is to execute on its preferred portfolio, including, but not limited to, adding the proposed CT Project, adding solar and wind resources, and retiring coal generation. She concluded, based on her experience with NIPSCO's energy efficiency initiatives, NIPSCO could not derive sufficient energy savings to replace this generation.

NIPSCO engaged in the 2022 RFP process to inform its planning activities. Multiple RFPs were issued in 2022 to identify costs and availability of resource options to fulfill the 2021 IRP's short-term action plan.

c. Conclusion. NIPSCO conducted the 2022 RFP to meet its capacity needs, and the RFP responses enabled NIPSCO to consider a variety of alternatives. Given the foregoing evidence, the Commission finds Petitioner has satisfied the requirement under

Ind. Code § 8-1-8.5-4(b)(2); it considers alternative methods for providing reliable, efficient, and economical electric service, including the refurbishment of existing facilities, conservation, load management, cogeneration, and renewable energy sources. NIPSCO's 2021 IRP and subsequent 2023 portfolio analysis show that the proposed construction of the CT Project at the Schahfer site is a reasonable, least-cost resource to support NIPSCO's Short Term Action Plan and meet its customers' needs for electricity. The CT Project is designed to reliably cycle in response to the MISO market and will displace the retiring Schahfer coal units with more efficient and controllable load-following capacity.

Based on the evidence of record, the Commission finds Petitioner has shown a need for the proposed CT Project and that public convenience and necessity require or will require Petitioner's construction of the CT Project.

v. Competitive Procurement. Ind. Code § 8-1-8.5-5(b)(5) requires us to make certain findings under Ind. Code § 8-1-8.5-5(e) if the proposed facility has a generating capacity of more than 80 MW, as is the case here:

> Before granting a certificate to the applicant, the commission:
>
> (1) must, in addition to the findings required under subsection (b), find that:
> (A) the estimated costs of the proposed facility are, to the extent commercially practicable, the result of competitively bid engineering, procurement, or construction contracts, as applicable; and
> (B) if the applicant is an electricity supplier (as defined in IC 8-1-37-6), the applicant allowed or will allow third parties to submit firm and binding bids for the construction of the proposed facility on behalf of the applicant that met or meet all of the technical, commercial, and other specifications required by the applicant for the proposed facility so as to enable ownership of the proposed facility to vest with the applicant not later than the date on which the proposed facility becomes commercially available; and
> (2) shall also consider the following factors:
> (A) Reliability.
> (B) Solicitation by the applicant of competitive bids to obtain purchased power capacity and energy from alternative suppliers.
>
> The applicant, including an affiliate of the applicant, may participate in competitive bidding described in this subsection.

There are two different requirements for a CPCN. The first, Ind. Code § 8-1-8.5-5(e)(1)(A), is to confirm the reasonableness and reliability of the cost estimate. The second, Ind. Code § 8-1-8.5-5(e)(1)(B), is to assure actual costs incurred are, to the extent commercially practicable, based on competitive procurement.

NIPSCO conducted multiple RFPs in 2022 to identify the costs and availability of resource options to fulfill the 2021 IRP's short-term action plan and to respond to changing market conditions, including an RFP for a gas-fired generation resource. The RFPs provided actionable

resource cost data that incorporated the latest policy, technology, and macroeconomic information. The RFPs provided information related to the latest costs of storage resources and the viability of alternative natural gas peaker options at the time they were solicited.

The statute requires the estimate to be the result, to the extent commercially practicable, of a competitively bid engineering, procurement or construction contract. Petitioner conducted the EPC RFP bid event and leveraged the information through that process to develop its best estimate for the cost to construct the CT Project through a multi-prime contracting strategy. NIPSCO's best estimate of construction reflects information received from equipment bid events for the CT original equipment manufacturer, generator step-up transformers, unit auxiliary transformers, and diesel generator. Accordingly, we find Ind. Code § 8-1-8.5-5(e)(1)(A) has been satisfied and that the cost estimates of the proposed facility are, to the extent commercially practicable, the result of competitively bid engineering, procurement, or construction contracts. Mr. Baacke described the construction and bid process NIPSCO will use through the multi-prime contracting strategy, whereby NIPSCO plans to develop competitive bids for all major scopes of construction. He testified that under the planned construction and bid process, NIPSCO will allow third parties to submit firm and binding bids for construction of the CT Project on NIPSCO's behalf that meet all of the technical, commercial, and other specifications so as to enable ownership of the CT Project to vest with NIPSCO no later than the date the facility becomes commercially available. This satisfies Ind. Code § 8-1-8.5-5(e)(1)(B).

Regarding Ind. Code § 8-1-8.5-5(e)(2), based on the evidence of record, we find the proposed CT Project is reliable. The record establishes Petitioner engaged in an All-Source RFP process to inform its overall generation transition plan. Thus, we find that the requirements of Ind. Code § 8-1-8.5-5(e) are satisfied.

vi. Conclusion on CPCN for CT Project. Based on the evidence of record, the Commission finds NIPSCO has met the requirements of Ind. Code ch. 8-1-8.5 and that the public convenience and necessity will be served construction of the CT Project. Therefore, we grant NIPSCO's request for a CPCN for its CT Project, subject to the findings and conditions of this order.

B. Ongoing Review of CT Project Under Ind. Code § 8-1-8.5-6(a). Ind. Code § 8-1-8.5-6(a) addresses the Commission's review of facilities under construction as follows:

> In addition to the review of the continuing need for the facility under construction . . . the commission shall, at the request of the public utility, maintain an ongoing review of such construction as it proceeds. The applicant shall submit each year during construction, or at such other periods as the commission and the public utility mutually agree, a progress report and any revisions in the cost estimates for the construction.

NIPSCO requested ongoing review of the CT Project, including review of progress reports and any revisions to the best estimate, as the construction proceeds, and associated ratemaking treatment consistent with such review. OUCC witness Mr. Krieger recommends the Commission require NIPSCO to submit quarterly progress reports providing construction status, and accounting updates including project to date spending and remaining balances of contingency, escalation, owner's costs and indirects. Ms. Becker testified Mr. Krieger's recommended quarterly reporting

requirements go beyond the yearly reporting required by the statute. She stated NIPSCO plans to file its GCT Mechanism semi-annually, which will provide the Commission and the parties an opportunity to review costs incurred to date and relevant project updates. She stated this cadence already exceeds the annual update requirement in the statute and that requiring quarterly reports from NIPSCO on top of this review is unnecessary and excessive. We find Ms. Becker's proposal reasonable given that it is more than contemplated by the statute.

We find NIPSCO shall report to the Commission a summary of the information related to the CT Project as contemplated under Ind. Code § 8-1-8.5-6(a), including any changes to scope, schedule, and the best estimate. In its initial report, NIPSCO is directed to include: (1) manufacturer, model number, and operational characteristics of the turbine generator and (2) anticipated total annual MW-hour ("MWh") output for the CT Project in each of its semi-annual GCT filing stylized as 45947 GCT XX. The initial report shall be filed on or before December 30, 2024 as a compliance filing in this Cause.

NIPSCO shall report semi-annually in this Cause to the Commission a summary of the information related to the CT Project, including safety, scope, schedule, and owner's cost contingency, as well as revisions to the cost estimate and update on the natural gas transportation and lateral pipeline. In addition, due to recent global supply chain issues that could potentially limit the availability of components necessary to build the CTs, Petitioner shall include in its semi-annual filings, an update on any supply-chain-related challenges and/or delays beginning on December 30, 2024.

The final project report shall contain the following information: (1) the actual total cost of construction; (2) the total MW output for the facility; and (3) the actual in-service (commercial operation) date for the facility. The final project report shall be filed in this Cause.

C. Clean Energy Project and Financial Incentives Under Ind. Code § 8-1-8.8-11. NIPSCO seeks approval of its CT Project as a clean energy project pursuant to Ind. Code § 8-1-8.8-11. Ind. Code § 8-1-8.8-11 provides that "[a]n eligible business must file an application to the commission for approval of a clean energy project" and that "[t]he commission shall encourage clean energy projects by creating financial incentives for clean energy projects, if the projects are found to be reasonable and necessary." An "eligible business" is an energy utility that "proposes to construct or repower a facility described in IC 8-1-37-4(a)(21)." Ind. Code § 8-1-8.8-6(5). A "clean energy project" similarly includes "[p]rojects to construct or repower a facility as described in IC 8-1-37-4(a)(21)" Ind. Code § 8-1-8.8-2(5). We have already found that NIPSCO is an "energy utility." The only disputed issue of applicability is whether the CT Project qualifies as a project under Ind. Code § 8-1-37-4(a)(21). That subsection includes in the definition of "clean energy resource . . . [e]lectricity that is generated from natural gas at a facility constructed or repowered in Indiana after July 1, 2011, which displaces electricity generation from an existing coal fired generation facility." NIPSCO witness Mr. Walter testified the CT Project will displace electricity generated from the coal-fired generating plants at Schahfer Units 17 and 18 and Michigan City Unit 12.

CAC witness Mr. Inskeep asserted Schahfer Units 17 and 18 are retiring in 2025 "regardless of the fate of the CT Project." Mr. Inskeep stated NIPSCO did not demonstrate the CT Project is displacing electricity generated from the coal-fired Schahfer Units 17 and 18 and

Michigan City Unit 12. NIPSCO witness Mr. Stanley's stated NIPSCO will be using the injection rights from the retiring Schahfer units for purposes of MISO interconnection. NIPSCO's 2021 IRP's Short Term Action Plan plainly shows NIPSCO's overall plan to retire Schahfer Units 17 and 18 and Michigan City Unit 12 are related to and dependent on the addition of several resources, including a gas peaking resource. NIPSCO witness Mr. Holcomb explained that along with increasing levels of zero-emission renewable energy in the electric system, the CT Project will keep NIPSCO and NiSource on track to achieve their target of a 90% reduction in Scope 1 GHG emissions by 2030, compared to 2005 levels.

Partial displacement of retiring coal-fired energy generation with a gas peaking resource has been a component of NIPSCO's IRP modeling and related CPCN regulatory filings since 2021. As such, we find the CT Project is being constructed to displace energy from an existing coal-fired generation facility and is therefore eligible for the relief provided in Ind. Code § 8-1-8.8-11.

i. <u>The Clean Energy Project is Just and Reasonable</u>. According to Ind. Code § 8-1-8.8-11, the Commission shall encourage clean energy projects by creating financial incentives for such projects, if found to be just and reasonable. While Chapter 8.8 does not set forth specific factors the Commission should consider in approving a clean energy project, the Commission has considered some of the factors outlined in Chapters 8.5 and 8.7 in other cases. Similarly, in determining the reasonableness and necessity for the CT Project, we find it appropriate to consider the principles reflected in the following Chapter 8.5 factors in our consideration: (1) the cost of the CT Project; (2) the consistency of the CT Project to NIPSCO's 2021 IRP; (3) the need for the CT Project; (4) and the competitive solicitation of the CT Project.

a. <u>The Cost of the CT Project</u>. The evidence in this Cause supports a finding that the energy to be generated by the CT Project is reasonably priced compared to other alternatives and provides material benefits. The best estimate of the costs is $100 million below the price for an EPC contract for a comparable facility and the cost is consistent with the costs assumed in the 2023 portfolio analysis.

b. <u>Consistency of the CT Project to NIPSCO's IRP</u>. The CT Project is consistent with NIPSCO's 2021 IRP (as updated in the 2023 portfolio analysis).

c. <u>The Need for the CT Project</u>. The CT Project fills the need for fast-start, quick-ramping generation that will complement NIPSCO's overall generation transition and follow the load. This evidence reflects that MISO, NIPSCO's grid operator, has indicated a system-wide need for controllable resources to ensure system reliability, particularly as more intermittent resources are added to the system. NIPSCO has demonstrated that the CT Project is necessary to assure reliability, resiliency, and stability of NIPSCO's supply of electricity.

d. <u>The Competitive Solicitation of the CT Project</u>. We have previously found and reiterate that NIPSCO's procurement of the CT Project has been and will continue to be through competitive solicitation.

Based on the evidence of record, we find the CT Project is a clean energy project under Ind. Code § 8-1-8.8-11 and is just reasonable. The record shows the addition of the CT Project to NIPSCO's resource mix will provide needed energy and capacity. We find the energy and capacity

provided through the CT Project are reasonable and necessary additions to NIPSCO's portfolio of generating resources to meet the need for electricity within NIPSCO's service area, while also mitigating the risk through the diversification and use of an economic mix of resources that provides flexibility.

ii. Cost Recovery. Having found the CT Project is a clean energy project and is eligible for the financial incentives pursuant to Ind. Code § 8-1-8.8-11 ("Section 11"), we turn now to NIPSCO's proposal to recover its costs during construction through the GCT Mechanism until such time as the project is included in base rates after being placed in service. Petitioner's witness Mr. Blissmer described the proposed GCT Mechanism and how it would work. NIPSCO anticipates these filings will be made by October 15 (reflecting the forward-looking period of March through August) and April 15 (reflecting the forward-looking period of September through February). NIPSCO anticipates a 120-day procedural schedule from filing to Commission order and rate implementation (on a bills rendered basis). Any variance between the forecasted tracker revenue requirement and the amounts collected will be compared to the actual revenue requirement based on the final books and records. The resulting variance would be captured in a reconciliation report within each tracker filing.

The revenue requirement for capital costs included in the GCT will be calculated by first computing the monthly average CWIP, or net plant in service when appropriate, over the forecasted six-month period. NIPSCO's direct testimony reflected NIPSCO would then multiply the weighted monthly average for the forecasted billing period by NIPSCO's monthly effective Weighted Average Cost of Capital ("WACC"). Up and until the CT Project is placed in service, there would be no depreciation expense. When and to the extent the CT Project is projected to be placed in service in a six-month forecast period, the GCT will commence the recovery of depreciation expense at NIPSCO's most recently approved depreciation rates (currently Cause No. 45772), which would be reconciled when actual depreciation expense is recognized in a future tracker. This avoids any deferral of depreciation expense. Similarly, forecasted property taxes will be included in the GCT and reconciled when actual property tax expense is recognized in a future tracker.

Mr. Blissmer testified NIPSCO proposes to allocate the costs associated with the CT Project based on NIPSCO's Commission approved demand allocators for the GCT Mechanism, whereby the demand allocators are based upon revenue attributable to each of NIPSCO's rate schedules used to establish NIPSCO's Commission approved electric base rates in Cause No. 45772. NIPSCO will adjust its allocation percentages to reflect the significant migration of customers amongst the various rates for each semi-annual tracker filing, as it does with other tracking mechanisms. This adjustment is appropriate to prevent any unintended consequences of the migration of customers between rates and to properly allocate their share of the revenue requirement. He described other changes to NIPSCO's electric service tariff relating to the proposed GCT Mechanism: (1) addition of Rider 595 – Generation Cost Tracker; (2) addition of Appendix L – Generation Cost Tracker Factors; (3) update to Appendix A to include Rider 595; and (4) update to the Table of Contents to add Rider 595 and Appendix L. NIPSCO anticipates its first GCT Mechanism filing would be October 15, 2024, or within 30 days of a final order in this Cause, whichever is later. As an additional financial incentive under Section 11, NIPSCO requests the operating income associated with the CT Project be included in the total electric Comparison of Electric Operating Income for purposes of the Ind. Code § 8-1-2-42(d) earnings test.

Mr. Blissmer explained how this proposed GCT Mechanism is authorized by new legislation. He testified House Enrolled Act 1421 ("HEA 1421"), among other things, amended the definition of "clean energy projects" in Ind. Code § 8-1-8.8-2 to include "[p]rojects to construct or repower a facility described in IC 8-1-37-4(a)(21)" and amended Section 11(a)(1) limiting when CWIP ratemaking can be authorized for a clean energy project as a financial incentive.

Mr. Blissmer testified NIPSCO's proposal satisfies the additional requirements relating to the authorization of CWIP ratemaking for a clean energy project as a financial incentive stating HEA 1421, among other things, amends Section 11(a) concerning financial incentives to provide:

> The commission may not approve a financial incentive under this subdivision unless the commission finds that the eligible business has demonstrated the timely recovery of costs and expenses incurred during the construction and operation of the project: (A) is just and reasonable; and (B) in the case of construction financing costs, will result in a gross financing savings over the life of the project.

Mr. Blissmer testified the construction financing costs will result in a gross financing savings over the life of the project. He explained the Summary tab includes the results from the data contained in the remaining tabs and presents two scenarios: (1) the top half presents the revenue requirement and financing costs portion of the revenue requirement under NIPSCO's proposed CWIP ratemaking treatment, and (2) the bottom half presents the same information under an alternative scenario where the asset is reflected in rates after being placed in service as part of a general rate case. He stated that under both scenarios, the CT is assumed to be placed in service in December 2027, the general rate case test year is assumed to be calendar year 2027, and the Step 2 rates in that general rate case are assumed to become effective on a bills rendered basis in March 2028. He explained that from that point forward, the sequence and timing of rate implementation under both scenarios is the same, as the CT Project under the GCT will have rolled into base rates and that the only difference from March 2028 over the remaining life of the project is the result of the higher accrued rate base (including regulatory asset) produced by the accrual of AFUDC and post-in service carrying costs ("PISCC") under the traditional model. He explained he has not included property taxes in the calculation because property taxes are not financing costs. He did include depreciation expense because the regulatory asset resulting from the deferral of depreciation expense would be reflected in rate base and thus depreciation does produce different financing costs under the two scenarios.

Mr. Blissmer concluded under NIPSCO's forward-looking GCT proposal, the total revenue from financing costs is $1,609,808,326, and under the traditional general rate case scenario, the total revenue from financing costs is $1,691,794,736, with the difference between these two amounts of $81,986,410 being the gross financing savings over the life of the CT Project. With a backward looking GCT Mechanism, the total gross financing savings over the life of the CT Project would be $48,019,573.

Mr. Blissmer testified NIPSCO's proposed financial incentive of CWIP ratemaking is just and reasonable. He stated the gross financing savings produces lower rates for customers. NIPSCO's proposal improves its cash flows and avoids rate shock to customers. He explained the primary benefit for a utility from CWIP ratemaking, from a financial health standpoint, is that it will provide NIPSCO cash flow during a potentially lengthy construction period. He testified CWIP ratemaking improves near term cash flow and mitigates the negative effects of the

significant additional debt taken on to construct the project.

In addition to CWIP ratemaking resulting in savings and producing lower rates for customers, Mr. Blissmer testified that it has long been recognized that CWIP ratemaking is a benefit to customers because it prevents so-called "rate shock." He explained that for large capital projects, waiting until the project enters service to include costs in rate base can lead to a significant one-time increase in the rate base and, in return, rates and that CWIP protects against that type of rate shock by phasing in the costs of the new facilities over the construction period.

Mr. Blissmer testified the exact estimated bill impact of the CT Project for an average residential customer will be dependent on several factors. However, assuming issuance of a CPCN for the CT Project and approval of the proposed GCT Mechanism as described above, NIPSCO currently estimates costs in the first GCT filing after approval would result in an incremental 2025 charge of approximately $0.56 to a 668 kWh per month residential bill, which is significantly lower than the $1.25/month impact based on a 2026 in-service date.

OUCC witness Ms. Baker objected to using the WACC in the calculation of CWIP ratemaking in the GCT. She contended NIPSCO should instead use project-specific financing costs or the cost of short-term debt.

IG witness Mr. Gorman testified the CWIP tracker is not just and reasonable simply because there are financial savings. Both IG witness Mr. Gorman and CAC witness Mr. Inskeep claimed the analysis of gross financing savings is inconsistent with Ind. Code § 8-1-8.8-11(a)(1)(B) in that it does not include net present value analysis. Mr. Inskeep also objected to the forward-looking version of the GCT Mechanism, alleging it was inconsistent with the verb tense of Ind. Code § 8-1-8.8-11(a)(1)and did not provide for "timely" recovery of costs.

In his rebuttal testimony, Mr. Blissmer testified NIPSCO is modifying its GCT proposal to remove WACC, and to apply its then current AFUDC rate. He stated he recalculated the gross financial savings from the use of CWIP ratemaking using both the forward-looking (NIPSCO's proposal) and backward-looking (NIPSCO's alternative proposal) using the estimated AFUDC rate instead of the WACC. He testified that (1) as shown in Petitioner's Exhibit 8-R Attachment 8-R-A, with the forward-looking GCT, the gross financial savings are now estimated to be over $9 million greater utilizing the estimated AFUDC rate than the savings calculated in his supplemental direct testimony using the WACC, and (2) as shown in Attachment 8-R-B, with the backward looking GCT, the gross financial savings are now estimated to be over $6 million greater utilizing the estimated AFUDC rate. He testified both alternatives continue to produce gross financial savings when compared to traditional ratemaking consistent with Ind. Code § 8-1-8.8-11(a)(1)(B), with the forward-looking version producing greater gross financial savings. Mr. Blissmer in his rebuttal testimony also responded to the contentions of Messrs. Gorman and Inskeep in opposition to the proposed GCT Mechanism. Mr. Inskeep claimed the delay of in-service date of the CT Project has caused an increase in total financing costs, which Mr. Blissmer explained fails to acknowledge his supplemental direct testimony that the one-year delay produces $65 million in customer savings through 2028.

Having found the CT Project is "clean energy project" under Ind. Code § 8-1-8.8-2(5) and having found the CT Project is just and reasonable, we are now required by Ind. Code § 8-1-8.8-11(a) to create financial incentives for the CT Project. Specifically, NIPSCO has requested we approve its proposed GCT Mechanism, which would provide for construction work in progress ratemaking as allowed by Ind. Code § 8-1-8.8-11(a)(1). Subsection 11(a)(1) provides that we may authorize "[t]he timely recovery of costs and expenses incurred during construction and operation of the project," but we may not do so "unless the commission finds the eligible business has demonstrated that the timely recovery of costs and expenses during the construction and operation of the project: (A) is just and reasonable; and (B) in the case of construction financing costs, will result in a gross financing cost savings over the life of the project."

Mr. Blissmer presented the calculation of his gross financial savings in his direct and supplemental direct testimony. Using the forward-looking GCT, Mr. Blissmer calculated the gross financial savings in direct testimony at $81,986,410 over the life of the CT Project. Using the more traditional backward looking GCT Mechanism, there would be reduced savings of $48,019,573. In rebuttal, Mr. Blissmer changed the financing cost rate to the AFUDC rate rather than the WACC in response to OUCC witness Mr. Baker. This change increased the gross financing cost savings by $9 million (total savings of approximately $91 million) for the forward-looking version and by $6 million (total savings of approximately $54 million) for the backward-looking version.

IG witness Mr. Gorman and CAC witness Mr. Inskeep objected to Mr. Blissmer's calculations on the grounds that they were not done on a present value basis. The statute, by its terms, does not require the calculation to be done based upon net present value. Instead, the statute requires the demonstration of gross financing cost savings over the life of the project. The Commission is a creature of statute with delegated authority from the Indiana General Assembly. When a statute does not require interpretation, and is unambiguous as Section 11 is, the Commission shall follow the law as written. Had the General Assembly intended the calculation to be done on a net present value basis as argued by Messrs. Gorman and Inskeep, it would not have used the word "gross" and would have instead used "net present value." We find that, as calculated by NIPSCO witness Mr. Blissmer, both the forward-looking and backward-looking versions of the proposed GCT Mechanism will generate "gross financing cost savings" over the life of the CT Project.

We are unpersuaded by Messrs. Gorman and Inskeep's assertion NIPSCO did not demonstrate the proposed GCT Mechanism as just and reasonable, particularly because neither witness responded substantively to Mr. Blissmer's direct testimony describing how the GCT benefits customers through the avoidance of so-called "rate shock" when a large construction project is reflected in rates in a single step. By recovering costs through the GCT Mechanism during the construction period, the rate impact from the CT Project will be reflected in steps over six-month increments. The ultimate cost to customers once the CT Project is fully reflected in rates will be lower because of the greatly reduced AFUDC.

The General Assembly has specifically directed affordability as one of the attributes to be considered in the context of generation transition. One of the tools provided by the General Assembly in the case of transition to clean energy projects is a CWIP tracker, which, as explained by Mr. Blissmer, produces the benefits of lower rates and smaller rate increases. We cannot simply ignore the benefits a CWIP tracker will contribute to affordability by lowering rates and smoothing

and mitigating rate increases during generation transition. NIPSCO's testimony on the overall benefits of CWIP ratemaking on credit quality, which ultimately informs the carrying charge applied to NIPSCO's investment and, therefore, customer rates, was effectively unrebutted. Mr. Inskeep asserted various other arguments against CWIP ratemaking generally, including that it creates generational inequities and erodes a utility's incentive to efficiently manage a project. These are not objections to whether this proposal meets the requirements of the statute, and they ignore the fact that the legislative decision has already been made to allow CWIP ratemaking. We find that, under Section 11, both the forward- and backward-looking versions of NIPSCO's proposed GCT Mechanism are just and reasonable.

We now move to the question of which method we should approve: the forward-looking or backward-looking GCT. As explained by Mr. Blissmer, NIPSCO has proposed the backward-looking GCT Mechanism in the alternative in the event we were not to approve the forward-looking version. With the forward-looking GCT, NIPSCO would reflect CWIP financing costs projected to occur over the next six-month billing period in each tracker filing. The projected CWIP financing costs would then be adjusted to the actual incurred costs and expenses by way of the reconciliation process. In this fashion, there would be no AFUDC reflected in the total cost of the CT Project except for the limited AFUDC that has already been accrued and expected to be accrued until rates take effect in March 2025 under the GCT Mechanism. In addition, there would be no depreciation to defer. The backward-looking GCT, in contrast, would reflect CWIP financing costs that had been incurred over the previous six-months. With the backward-looking GCT, there would be AFUDC accrued during each six-month period until the costs are reflected in the GCT. In addition, there would be depreciation deferred between the in-service date and reflection in rates. This AFUDC and deferred depreciation would increase the overall cost of the CT Project, which is why the backward-looking version of the GCT produces less gross financing cost savings.

Mr. Inskeep had two objections to the forward-looking version of the GCT. First, he claimed the statute uses past tense and that this precludes recovery of projected costs. Second, he claimed that because NIPSCO would be recovering financing costs before they have been incurred, the recovery would not be "timely" as the statute requires. We are unpersuaded by either argument. First, it is important to note that whether the tracker looks forward or backward will not change that NIPSCO will recover only its actual costs. With the reconciliation process inherent in the proposed tracker, NIPSCO's recovery will always be based upon its actual costs incurred. The statute requires that the mechanism provide for timely recovery of costs and expenses incurred during construction. With the forward-looking mechanism coupled with its reconciliation process, NIPSCO's proposal provides for recovery of the costs and expense that are actually "incurred," and this recovery begins during the same six-month period during which those costs are being incurred. The forward-looking GCT Mechanism would result in timely recovery consistent with the statute. In addition, given that the forward-looking GCT Mechanism produces approximately $37 million in gross financing cost savings ($91 million less $54 million) when compared to the backward-looking mechanism, it is the method that creates a more affordable result for customers. Further, Ind. Code § 8-1-8.8-11(a)(4) authorizes us to approve other financial measures we consider appropriate, and we consider the forward-looking GCT to be appropriate. The General Assembly has established an infrastructure policy "to use all practicable means and measures, including financial and technical assistance, in a manner calculated to create and maintain conditions under which utilities plan for and invest in infrastructure necessary for operation and

maintenance while protecting the affordability of utility services for present and future generations of Indiana citizens." Ind. Code § 8-1-2-0.5. Denying a utility the use of a forward-looking tracker that would produce an additional $37 million in gross financial savings for customers based upon verb tense would be inconsistent with this overall infrastructure policy and the pillar of affordability. Accordingly, we find NIPSCO's proposed forward-looking GCT Mechanism using the AFUDC rate as reflected on rebuttal should be approved.

We further approve Petitioner's request that the operating income associated with the CT Project recovered through the GCT Mechanism be included in the total electric Comparison of Electric Operating Income for purposes of the Ind. Code § 8-1-2-42(d) earnings test. This is an appropriate additional financial incentive under Section 11, and it is therefore approved.

D. <u>The Five Pillars</u>. In HEA 1007, the Indiana General Assembly declared it is the continuing policy of the State that decisions concerning Indiana's electric generation resource mix, energy infrastructure, and electric service ratemaking constructs must consider each of the five pillars of electric utility service. See also Ind. Code § 8-1-8.5-4(b)(4). Ind. Code § 8-1-2-0.6 codifies the five pillars of electric utility service: as reliability, affordability, resiliency, stability, and environmental sustainability. NIPSCO witness Ms. Becker's Petitioner's Exhibit No. 1 Attachment 1-C identifies the seven different NIPSCO witnesses who sponsored testimony supporting each of the Pillars.

We address the Five Pillars in the order in which they are listed in Ind. Code § 8-1-2-0.6, acknowledging that no one pillar takes precedence over the others and that each must be balanced against the others.

Based on the evidence of record and having considered the Five Pillars enumerated in Ind. Code § 8-1-2-0.6, the Commission finds NIPSCO's proposed CT Project and related proposals are consistent with and appropriately balance the legislative directive in this state policy statement.

i. <u>Reliability</u>. Reliability is ensuring customers have the power they need when they need it. We have recognized that in a dramatically shifting generation landscape the need for fast start/quick ramping resources is magnified. Southern Ind. Gas & Elec. Co., Cause No. 45564 (IURC 6/28/2022). NIPSCO witness Mr. Austin's testimony informs us this need is increasing. Evidence of record supports findings that the proposed CT Project addresses needs identified by key stakeholders, including MISO, NERC, the MISO IMM, and others, and addresses needed attributes to directly support NIPSCO's overall generation portfolio.

Both the NERC and MISO have warned stakeholders that, as the penetration of solar generation increases, the challenge of steeper ramping needs for the non-solar fleet magnifies. Mr. Austin cited numerous publications from NERC, MISO, and MISO's IMM discussing the need to install fast-starting, quick ramping generation to support the growing portfolio of renewable resources and maintain reliable service. NERC specifically recognizes the important role regulatory policy plays in ensuring a reliable grid. Mr. Austin explained that 2023 marked the first year, "energy policy" has been added as a risk profile to Electric Reliability Organization ("ERO") Priorities Report. Mr. Austin, quoted the ERO Priorities report stating: "[t]raditional resource adequacy approaches that assume the system is adequately planned if there is enough generation capacity during peak load hours have become insufficient given the accelerated changes in

resource mix, extreme weather events, and fuel dependencies." Petitioner's Exhibit No. 3. The 2022 Long-Term Reliability Assessment issued December 2022 states as follows:

> As more solar and wind generation is added, additional flexible resources are needed to offset these resources' variability, such as supporting solar down ramps when the sun goes down and complementing wind pattern changes. This can be accomplished by adding more flexible resources within committed portfolios or by removing system constraints to flexibility.

Further, NIPSCO witness Mr. Austin explained the proposed CT Project will help meet MISO's Resource Adequacy Requirements. The 2023 Organization of MISO States- MISO Survey Results (published July 14, 2023) reflect delayed retirements and capacity additions have resulted in a capacity surplus of 1,500 MW for the 2024/25 planning year. Id. Demand growth is projected to continue for five years across all four seasons at 0.8 GW or 0.68% per year on average across the MISO footprint and the results show a deterioration of MISO's current capacity surplus above the required capacity level, to a sizeable projected shortfall of 2,100 MW in summer 2025/26. This demonstrates a growing need for dispatchable resources to support system reliability within the MISO region, including Indiana.

NIPSCO witness Mr. Austin explained why batteries, inverter-based resources ("IBRs"), and energy storage resources ("ESR") do not meet system reliability needs. NERC and MISO's IMM reach similar conclusions, as the NERC highlights in its 2022 Long-Term Reliability Assessment and notes:

> … IBRs produce low amounts of fault currents based on control functions. Changing fault current magnitudes and characteristics in parts of the system with high penetrations of IBRs has the potential to invalidate current protection system designs, potentially leading to more protection system misoperation.

The IMM, in its 2022 State of the Market Report for the MISO Electricity Markets, concurs, stating that:

> Although ESRs can provide tremendous value in managing the fluctuations in intermittent output and maintaining reliability, ESRs are not fully substitutable for conventional generation. This is particularly true as the quantities of ESRs rise, which causes the marginal value of ESRs to fall.

NIPSCO witness Mr. Stanley explained MISO's interest in the significant transition of electric generation in the MISO region:

> MISO is focused on reliability, and that means it is focused on ensuring the resource portfolio has the necessary capability and attributes. Yet, due to decarbonization goals, economics and customer preferences, key existing resources will retire. Some plans to build new resources with the needed attributes are delayed or abandoned, and other technologies are not ready for broad deployment. Proposed replacement capacity has shown to be lacking key traits given current technologies. The gap between retirement capabilities and attributes is a growing reliability

concern.

Petitioner's Exhibit No. 6. The Executive Summary in the 2022 State of the Market Report goes on to outline different attributes or characteristics provided by different generation resource types and reflects that gas resources have a significant relative advantage over renewable resources in providing: (1) long duration energy at high output; (2) voltage stability; (3) ramp up capability; (4) rapid start-up; and (5) blackstart capability. It is these attributes that the CT Project will offer to NIPSCO's generation portfolio, for the benefit of all of its customers and the broader MISO region. In addition, while still in development and under review, NIPSCO witness Mr. Augustine cited from MISO's Resource Adequacy Subcommittee October 2022 presentation that noted the importance of key technical attributes like blackstart and detection of short circuit strength and prioritized a set of attributes associated with capacity, energy adequacy, flexibility, and essential reliability services. These priority attributes are consistent with the reliability criteria NIPSCO evaluated within the economic and non-economic assessments that were conducted during the 2021 IRP.

NIPSCO conducted extensive diligence on the reliability of the potential resource portfolios in its 2021 IRP. The Non-Economic Reliability Assessment evaluated each potential portfolio based on the following reliability criteria and metrics: (1) blackstart capability, (2) energy adequacy, (3) dispatchability, (4) operational flexibility and frequency support, (5) VAR support, (6) location, (7) predictability and firmness, and (8) short circuit strength. In 2023, NIPSCO conducted the Flexible Resource Analysis to assess the preferred portfolio's flexibility needs on an inter-hour and intra-hour basis, given the variability and intermittency of renewable resources and performed a sub-hourly analysis to provide insights into the type of market exposure NIPSCO could face as its portfolio evolves. The Flexible Resource Analysis showed the preferred portfolio of approximately 1,200 MW of flexible capacity by 2030 would be insufficient to meet net load and three-hour ramp requirements in extreme conditions without reliance on the market and revealed a 150 MW growth in NIPSCO's need for capacity with a 10-minute ramp rate by 2030. NIPSCO's CT Project in its preferred configuration is designed to fill this capacity gap ensuring service on NIPSCO's entire system is reliable.

Our review of the evidence of record regarding the attributes of the aeroderivative turbines leads us to conclude that their operational characteristics are a vital part of the CT Project's expected reliability. NIPSCO witness Mr. Baacke explained aeroderivative turbines are typically more efficient, start faster and more frequently, and fluctuate power generation faster to meet demand when compared to larger industrial frame turbines. We conclude it is these features that will allow NIPSCO to continue to install large volumes of renewable energy (which serves the environmental sustainability pillar discussed below) while still maintaining the ability to reliably and efficiently serve a heavy industrial customer base, as well as commercial and residential load, when intermittent renewable resources are not available for short or prolonged periods of time.

Finally, we note the CT Project's gas usage will be supported through NIPSCO's gas system, which already contains transportation rates, riders, and pooling options. NIPSCO's gas system is robust, with multiple interconnection points with seven interstate pipelines, which offer an uncommon level of supply diversity as natural gas generators are typically captive to only one interstate pipeline connection. This is an advantage for the CT Project, especially as compared to intermittent resources, and further bolsters its reliability and resiliency.

ii. Affordability. The addition of a large generation resource such as the CT Project will necessarily impact the cost of electric service NIPSCO provides to its customers. This illustrates the tension between the Five Pillars that naturally occurs as a utility invests to ensure the availability and delivery of reliable energy to its customers. The OUCC, IG, and CAC testimony each raised affordability concerns with NIPSCO's proposed CT Project and related cost recovery through the GCT Mechanism. The thrust of their varied concerns is the pillars of reliability, resiliency, and stability should not supplant meaningful consideration of the customer affordability of NIPSCO's request.

Although we are not approving rates as part of this proceeding, we are authorizing NIPSCO to construct a generation facility that will operate for many years and approving a recovery mechanism for costs associated with construction of the facility. Because a utility has limited control over nearly all the external factors that could impact its customers' ability to pay for utility service, the challenge for public utilities in the face of a highly consequential generation transition is to meet its customers' need for electric generation cost effectively. NIPSCO's evidence supports that its proposal for the CT Project does that.

The proposed CT Project originated from NIPSCO's 2021 IRP from which a preferred portfolio was selected as a lower cost option than alternatives. NIPSCO utilized a competitively bid EPC contract event and determined a multi-prime contracting strategy could save $100 million over the viable EPC bid it received. When NIPSCO determined supply chain constraints caused the originally contemplated in-service date to no longer be reasonably achievable, it reevaluated its approach and submitted supplemental direct testimony to shift the in-service date of the CT Project by one year to end of year 2027. This shift in in-service date produced an immediate savings for customers of $65 million over the course of the next five years through delayed rate implementation. In addition to these savings, NIPSCO's proposed GCT Mechanism will further produce gross financial cost savings of approximately $90 million over the life of the CT Project as compared to traditional ratemaking. Finally, the CT Project will not require additional pollution control technology to comply with GHG Rule and offers the flexibility to run as an intermediate load unit, which could serve to reduce NIPSCO's need to procure additional market capacity, which reduces exposure to price volatility to the benefit of NIPSCO's customers. Each of these facts demonstrate the steps NIPSCO took to address affordability as part of its overall project proposal.

While we acknowledge that a project of this size will inevitably lead to an increase in customers rates, we conclude that, when considered in totality, NIPSCO's CT Project supports the goal of utility service costs that are affordable and competitive across the customer classes.

iii. Resiliency. Resiliency is similar to reliability, and much of our discussion above regarding reliability is applicable here. Resiliency represents the distinct concept concerned with ensuring availability of electricity under changing or extraordinary system conditions. The fast start capabilities of the CT Project, especially given the configuration with aeroderivative units are a key component of resiliency. NIPSCO witness Mr. Walter testified NIPSCO has a need for additional winter capacity, and the CT Project will be a key part of ensuring the resiliency of NIPSCO's electric operations. Mr. Austin offered extensive confidential testimony that directly addressed how the CT Project will support resiliency.

In addition to the system's ability to respond to an acute system emergency or unexpected outage, longer-term resiliency can be considered based on evolving market rules, changing weather patterns, or climate-related phenomena. As outlined by NIPSCO witness Mr. Augustine, the 2023 portfolio analysis incorporated market shifts and changes that have occurred since the 2021 IRP, including the MISO seasonal resource adequacy construct. These changes point to an increased need for capacity-advantaged resources in NIPSCO's generation portfolio, a need which the CT Project directly fulfills.

iv. Stability. Stability is defined in the statute as the ability of the electric system to: (a) maintain a state of equilibrium during normal and abnormal conditions or disturbances and (b) deliver a stable source of electricity, in which frequency and voltage are maintained within defined parameters, consistent with industry standards. Stable sources of power provide a critical backbone to the grid, which is particularly vital during this dynamic time of significant generation transition. With renewable generation being a significant component of NIPSCO's generation portfolio transition since its 2018 IRP, NIPSCO conducted a Reliability Analysis as part of its 2021 IRP, which identified the need for longer-duration, flexible resources additions within its service territory. As gas turbines can operate continuously for extended durations, the CT Project clearly supports system stability. NIPSCO witness Mr. Stanley testified that gas resources have a significant advantage relative to inverter-based (e.g., renewable) resources, as gas resources can provide (1) long duration energy at high output; (2) voltage stability; (3) ramp up capability; (4) rapid start-up; and (5) blackstart capability. These characteristics, which were also discussed above in the Reliability discussion, are essential to a stable generation transition, and a stable generation transition drives value for utility customers. Evidence of record supports a finding that the CT Project offers these types of needed attributes and supports system stability for NIPSCO, Indiana, and the broader MISO region.

v. Environmental Stability. Environmental sustainability considers both the impact of regulations and the demand from customers for power from environmentally sustainable resources. The CT Project fits as part of NIPSCO's overall plan to retire all its coal-fired generation by 2028 and to reduce its carbon emissions from its electric operations by 90% measuring from a 2005 baseline. The CT Project will have the flexibility to run beyond its currently anticipated capacity factors and still maintain compliance with the newly adopted EPA GHG rule. The CT Project fits within an overall portfolio whereby NIPSCO has successfully transitioned away from a portfolio heavily reliant on coal to one that relies on a fleet of wind, solar, and battery energy storage resources. The intermittent capabilities of those renewable resources must be supported by the quick start/fast ramp capabilities of the CT Project.

OUCC witness Mr. Armstrong states that the determination of whether natural gas generation is environmentally sustainable is subjective. The CT Project supports increasing levels of renewable energy in the electric system and replaces capacity from NIPSCO's coal units that are planned to retire by 2025 and 2028. The retirement of coal generation and replacement with zero-emission generation and low/intermediate-load gas generation—such as the CT Project—keeps NIPSCO and NiSource on-track to achieve their target of a 90% reduction in Scope 1 GHG emissions by 2030, compared to 2005 levels. The efficiency of the aeroderivative turbines serves the environmental sustainability pillar. NIPSCO witness Mr. Holcomb explained that, at full load, the aeroderivative units are expected to meet the intermediate load emission standard in the EPA greenhouse gas rule and be allowed to operate at capacity factors up to 40%, as needed. The frame

unit is not expected to meet the intermediate load emission standard and would, therefore, be limited to a 20% capacity factor. This demonstrates how the proposed CT Project's configuration balances environmental sustainability while also supporting reliability, resiliency, and stability.

6. Confidentiality. NIPSCO filed a motion for protection and nondisclosure of confidential and proprietary information on September 12, 2023, January 16, 2024, and April 25, 2024. These motions related to information NIPSCO claimed to be trade secrets and protected from disclosure under Ind. Code §§ 8-1-2-29 and 5-14-3-4. Docket entries were issued on September 28, 2023, February 8, 2024, and March 13, 2024, finding such information to be preliminarily confidential and protected from disclosure under Ind. Code §§ 8-1-2-29 and 5-14-3-4. The confidential information was subsequently submitted under seal. The Commission finds the information that is the subject of these motions is confidential pursuant to Ind. Code § 8-1-2-29 and Ind. Code ch. 5-14-3, is exempt from public access and disclosure by Indiana law, and shall continue to be held by the Commission as confidential and protected from public access and disclosure.

IT IS THEREFORE ORDERED BY THE INDIANA UTILITY REGULATORY COMMISSION that:

1. NIPSCO is issued a certificate of public convenience and necessity under Ind. Code ch. 8-1-8.5 to construct an approximately 400 MW natural gas combustion turbine peaking plant to be located at NIPSCO's existing R.M. Schahfer site. This Order constitutes the certificate.

2. NIPSCO's estimated total cost of the CT Project in the amount of $641.2 million (excluding AFUDC) is approved as set forth herein.

3. NIPSCO's request for ongoing review of the CT Project is approved. NIPSCO shall file reports as described herein for the purpose of ongoing review in accordance with Ind. Code § 8-1-8.5-6.

4. The CT Project is approved as a clean energy project and NIPSCO's request for financial incentives, including timely cost recovery through construction work in progress ratemaking under Ind. Code Ch. 8-1-8.8 is approved.

5. NIPSCO is granted authority to recover costs incurred in connection with the CT Project through its Generation Cost Tracker Mechanism, as proposed, including approval of the specific ratemaking and accounting treatment approved herein. NIPSCO's proposed changes to its Electric Service Tariff relating to the GCT Mechanism are approved.

6. The Confidential Information submitted under seal in this Cause pursuant to the parties' requests for confidential treatment is determined to be confidential trade secret information as defined in Ind. Code § 24-2-3-2 and shall continue to be held as confidential and exempt from public access and disclosure under Ind. Code §§ 8-1-2-29 and 5-14-3-4.

7. This Order shall be effective on and after the date of its approval.

HUSTON, BENNETT, FREEMAN, VELETA, AND ZIEGNER CONCUR:

APPROVED:

I hereby certify that the above is a true and correct copy of the Order as approved.

_____

Dana Kosco
Secretary of the Commission

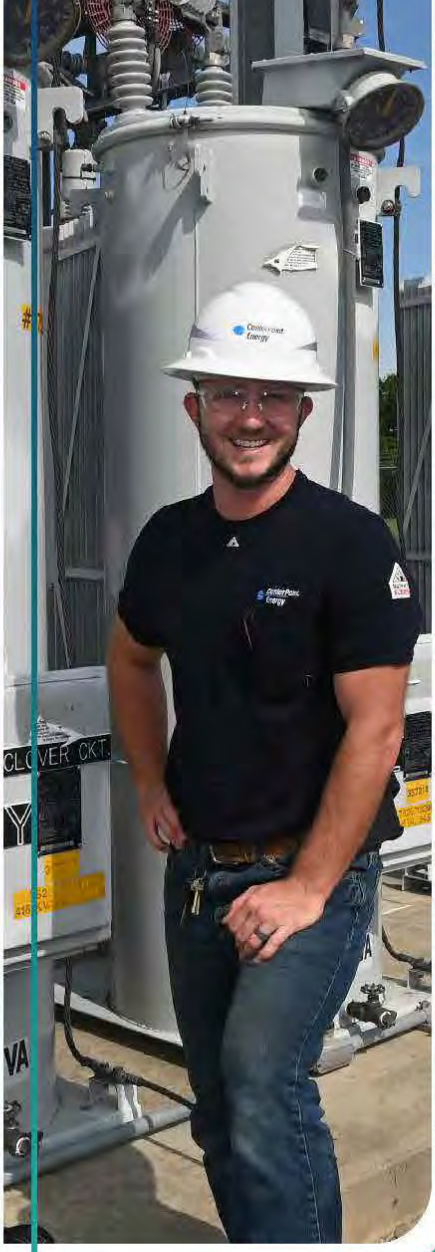
BEFORE THE UNITED STATES DEPARTMENT OF ENERGY

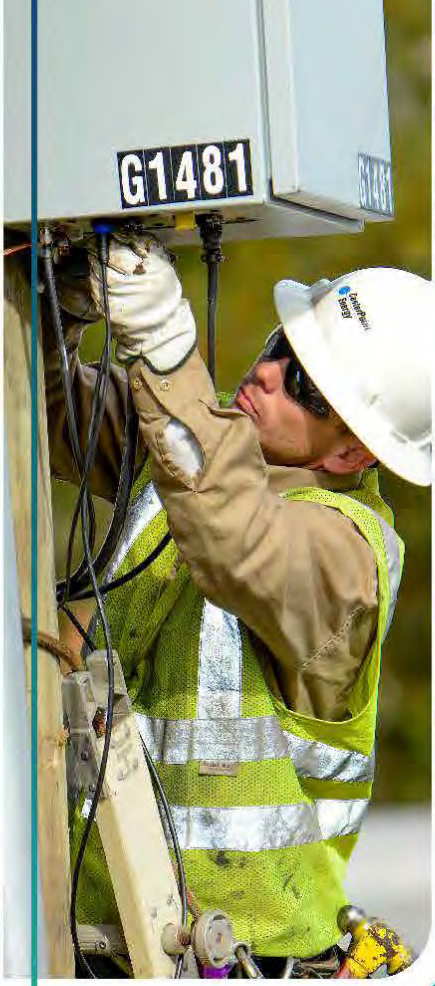
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and Northern Indiana Public Service Company LLC	)))))	Order No. 202-26-46
Federal Power Act Section 202(c) Emergency Order: Midcontinent Independent System Operator and CenterPoint Energy Indiana South	)))))	Order No. 202-26-47

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

Exhibit 21
CenterPoint Indiana 2025 IRP







2025
Integrated Resource Plan

CenterPoint® Energy

This page intentionally left blank for formatting purposes.

Table of Contents

Table of Contents **3**
Table of Figures **9**
Executive Summary (Non-Technical Summary) **12**
1. INTEGRATED RESOURCE PLANNING **43**
1.1. Integrated Resource Planning 44
1.1.1. Indiana's Five Pillars 45
1.1.2. State of the World 46
1.1.3. Generation Transition (MISO) 46
1.1.4. Political and Regulatory Environment 48
1.1.5. Environmental Regulations 49
1.1.6. Large Loads 49
1.1.7. CenterPoint Energy Rate Case and Community Engagement 50
1.1.8. CEI South Current Generation Portfolio 51
1.1.9. Status on Implementing Prior IRP (Retirements and Additions) 51
1.1.10. Culley 3 Conversion 52
2. RESOURCE PLANNING PROCESS **53**
2.1. Planning Structure 54
2.2. Real-World Inputs and Modeling Foundations 54
2.3. Development of Resource Strategies and Planning Scenarios 55
2.4. Stakeholder Engagement 56
2.5. Planning Scenarios 57
2.6. Reference Case 58
2.7. Alternative Scenarios 59
2.8. Planning Priorities and Guiding Principles 62
2.9. Comprehensive Portfolio Development & Testing 65
2.10. Portfolio Scorecard Evaluation 68
2.11. Analytical Process & Tools 69
2.11.1. Analytical Roadmap 69
2.11.2. Modeling Tools 70
2.11.3. Process Enhancements 70

3. FORECASTS AND KEY MODELING ASSUMPTIONS 74

3.1. Load Forecast 75

3.1.1. Methodology 75

3.1.2. Forecast Drivers and Data Sources 75

3.1.3. Model Framework 76

3.1.4. Reference Case 78

3.1.5. Alternate Scenarios 79

3.2. MISO 81

3.2.1. Planning Reserve Margin Requirement 81

3.2.2. Capacity Price 82

3.2.3. Addressing Resource Adequacy and Reliability Challenges 83

3.2.4. Generation Interconnection Process 86

3.2.5. Impact of Regulatory Changes 88

3.3. Fuel 89

3.3.1. Natural Gas 90

3.3.2. Coal 91

3.3.3. Uranium 92

3.4. Power Prices 92

3.5. Environmental Regulations 93

3.5.1. Effluent Limitations Guidelines (“ELG”) 93

3.5.2. Coal Combustion Residuals (“CCRs”) 94

3.5.3. Greenhouse Gas Regulations 94

3.5.4. 316(b) 95

3.6. Tax Incentives 95

3.6.1. Inflation Reduction Act (“IRA”) and One Big Beautiful Bill Act (“OBBBA”) .. 95

3.7. Resource Options 97

3.7.1. Current Resource Mix 97

3.7.2. Potential Future Resource Options 104

3.8. Transmission Planning & Distribution Planning 127

3.8.1. Transmission Planning Process 128

3.8.2. Existing Transmission System 128
3.8.3. Import and Export Capability Assessment 128
3.8.4. Transmission Facilities as a Resource 129
3.8.5. Distribution Planning Process 131
3.8.6. Evolving Technologies and System Capabilities 131
3.9. Other Modeling Assumptions 132
3.9.1. Resource Availability 132
3.9.2. MISO Direct Loss of Load Modeling 134
4. PORTFOLIO DEVELOPMENT AND EVALUATION 137
4.1. Portfolio Development 138
4.1.1. Optimization Runs 138
4.1.2. Final Portfolios for Risk Analysis 144
4.2. Evaluation Of Portfolio Performance 146
4.2.1. Scenario Risk Analysis (Simulated Dispatch in Each Scenario) 147
4.2.2. Probabilistic Risk Analysis (Simulated Dispatch 200 Runs Scorecard) 148
4.3. Results By Portfolio 151
4.3.1. Reference Case Portfolio 151
4.3.2. Convert F.B. Culley 3 to Natural Gas by 2035 152
4.3.3. Continue F.B. Culley 3 on Coal through 2045 153
4.3.4. F.B. Culley 3 on Coal to Small Modular Reactor (“SMR”) 154
4.3.5. F.B. Culley 3 to Simple Cycle Gas Turbine 155
4.3.6. Renewable Heavy Portfolio 156
4.3.7. F.B. Culley 3 Gas Conversion with Renewables 157
4.3.8. Low Regulatory Portfolio 158
4.3.9. High Regulatory Portfolio 159
4.3.10. Alternate High Regulatory Portfolio 160
4.3.11. F.B. Culley 3 Co-Fire Portfolio 161
4.3.12. Delayed Reference Case Portfolio 162
5. THE PREFERRED PORTFOLIO 164
5.1. Preferred Portfolio Recommendation 165

5.1.1. Description of the Preferred Portfolio 165
5.1.2. Reliability 166
5.1.3. Resilience 168
5.1.4. Stability 169
5.1.5. Environmental Sustainability 169
5.1.6. Affordability 170
5.1.7. Other 175
5.1.8. Fuel Inventory and Procurement Planning 177
6. THE ALTERNATE PREFERRED PORTFOLIO 178
6.1. Alternate Reference Case Portfolio Development 179
6.2. Portfolio Performance 181
6.2.1. Transmission System Impact of the Large Load Additions 183
6.2.2. Generation Planning for Large Loads 184
6.3. Description of the Alternate Reference Case Preferred Portfolio 185
7. SHORT TERM ACTION PLAN 187
7.1. Differences Between the Last Short Term Action Plan from What Transpired 188
7.1.1. Culley 3 Conversion 189
7.1.2. Posey Solar and Two New CTs 189
7.1.3. DSM 189
7.2. Discussion Of Plans For The Next 3 Years 189
7.2.1. Procurement of Resources 189
7.2.2. RFPs and Continued Evaluation of F.B. Culley 2 interconnection 190
7.2.3. DSM 190
7.2.4. Other Innovative Rate Design 190
7.2.5. Demand Response 190
7.2.6. Ability to Finance the Preferred Portfolio 191
7.2.7. Continuous Improvement 191
7.3. Schedule 191
8. TECHNICAL APPENDIX 192
8.1. Load Forecast Appendix 193

8.1.1. Forecast Inputs 193
8.1.2. Overview of Past Forecasts 196
8.1.3. Actual and Weather Normalized Energy and Demand Levels 199
8.1.4. Load Shapes 200
8.1.5. Advanced Metering Infrastructure and Continuous Improvement 209
8.2. Environmental Appendix 209
8.2.1. Air Emissions 209
8.2.2. Solid Waste Disposal 209
8.2.3. Hazardous Waste 210
8.2.4. Water Consumption and Discharge 210
8.3. DSM Appendix 210
8.3.2. Gross Savings 2025-2027 Plan 213
8.3.3. DSM Programs 213
8.3.4. Impacts 213
8.3.5. Avoided Costs 215
8.3.6. Estimated Impact on Historical Forecasted Peak Demand and Energy 216
8.3.7. Appliance Saturation Survey 216
8.4. Risk Appendix 217
8.4.1. Stochastics (Probabilistic Modeling) 217
8.4.2. Rate Metric Ranking 227
8.5. Transmission Appendix 227
8.5.1. MISO Regional Transmission Planning 227
8.5.2. Annual Transmission Assessment 228
8.5.3. DSM Impacts on Transmission and Distribution Systems 229
8.6. Public Advisory Process Appendix 229
8.6.1. Foundational Elements 230
8.6.2. Engagement Resources and Strategies 231
8.6.3. Stakeholder Input 235
8.6.4. Data Requests Summary 236
9. TECHNICAL APPENDIX ATTACHMENTS 238

10. IRP Rule Requirements Cross Reference Table 240

11. List of Acronyms/Abbreviations 256

Table of Figures

Figure 1-1 – Five Pillars 45
Figure 1-2 – Community Connect Sessions 50
Figure 1-3 – CEI South Generating Units 51
Figure 2-1 – 2025 Stakeholder Meeting Schedule 57
Figure 2-2 – Scenario Summary 61
Figure 2-3 – Objectives, Measures, & Metrics 64
Figure 2-4 – Portfolio Development Process 66
Figure 2-5 – Evaluation Objectives, Measures & Metrics 69
Figure 2-6 – Analytical Roadmap 70
Figure 3-1 – 2024 CEI South Annual Sales Breakdown 75
Figure 3-2 – Class Build-up Model 77
Figure 3-3 – Energy and Demand Forecast 78
Figure 3-4 – Alternate Scenario Forecasts 79
Figure 3-5 – Sensitivity Forecasts 80
Figure 3-6 – Alternate Reference Case 80
Figure 3-7 – 25/26 RBDC Impact on the Planning Resource Auction 81
Figure 3-8 – MISO Capacity Prices 82
Figure 3-9 – 2025-2026 MISO Seasonal Capacity Prices 82
Figure 3-10 - MISO Market Capacity Price Forecast 83
Figure 3-11 – MISO DLOL Accreditation Forecast 85
Figure 3-12 – ERAS Timeline 88
Figure 3-13 – Reference Case Natural Gas Price Forecast (2025$/MMBtu) 90
Figure 3-14 – Reference Case Coal Price Forecast (2025$/MMBtu) 91
Figure 3-15 – Reference Case Uranium Price Forecast (2025$/MMBtu) 92
Figure 3-16 – Reference Case Power Price Forecast (Nominal $) 93
Figure 3-17 – ACE Proxy Cost 95
Figure 3-18 – Reference and Alt Reference Scenario Tax Credits 96
Figure 3-19 – High Reg and Alt High Reg Scenario Tax Credits 96
Figure 3-20 – CEI South's Owned Generating Units (2026/2027 Planning Year) 98
Figure 3-21 – Gross Cumulative Savings 99
Figure 3-22 – Energy Efficiency Savings 101
Figure 3-23 – F.B. Culley 2 Potential Future Resource Options 105
Figure 3-24 – F.B. Culley 3 Potential Future Resource Options 106
Figure 3-25 – A.B. Brown Potential Future Conversion Options 107
Figure 3-26 – Simple Cycle Gas Turbine Technologies 108
Figure 3-27 – Combined Cycle Gas Turbine Technologies (Unfired Configuration) 109
Figure 3-28 – Combined Cycle Gas Turbine Technologies (Fired Configuration) 109
Figure 3-29 – Aeroderivative and Reciprocating Engines 110
Figure 3-30 – Wind Technologies 110
Figure 3-31 – Solar Technologies 111
Figure 3-32 – Hydroelectric Technologies 112
Figure 3-33 – Lithium-Ion Energy Storage 113
Figure 3-34 – Emerging Energy Storage Technologies 113

Figure 3-35 – Advanced Nuclear Technology 114
Figure 3-36 – Forward Looking Capital Cost Curves– Forward Looking Capital Cost Curves ... 115
Figure 3-37 – MPS versus Initial IRP Bundles Comparison – Sum of Incremental MWh 122
Figure 3-38 – Annual MWh EE Savings and Levelized Costs per Lifetime MWh Saved by Bundle 123
Figure 3-39 – EE and DR Bundle Comparison and Enhancements 125
Figure 3-40 – Resource Availability for Core Scenarios 133
Figure 3-41 – Resource Availability for Large Load Addition Cases 134
Figure 3-42 – Example of Smoothed Transition from SAC to DLOL for Solar Resources 136
Figure 4-1 – F.B. Culley 2 Deterministic Model Results 140
Figure 4-2 – Demand Side Management Deterministic Results 141
Figure 4-3 – Scenario Optimization Model Outputs 143
Figure 4-4 – Final Risk Analysis Portfolios 145
Figure 4-5 – Description of Portfolio Motivations 146
Figure 4-6 – Portfolio NPVRR (Million $) 147
Figure 4-7 – Portfolio Total CO_2 Emissions Over Study Period (Million Tons) 148
Figure 4-8 – IRP Portfolio Balanced Scorecard Color-Coded Comparison 150
Figure 4-9 - Reference Case Portfolio Results Dashboard 152
Figure 4-10 – Convert F.B. Culley to Natural Gas by 2035 Results Dashboard 153
Figure 4-11 – F.B. Culley 3 on Coal through 2045 Results Dashboard 154
Figure 4-12 – F.B. Culley 3 on Coal to Small Modular Reactor Results Dashboard 155
Figure 4-13 – F.B. Culley 3 to Simple Cycle Gas Turbine Results Dashboard 156
Figure 4-14 – Renewable Heavy Portfolio Results Dashboard 157
Figure 4-15 – F.B. Culley 3 Gas Conversion with Renewables Results Dashboard 158
Figure 4-16 – Low Regulatory Portfolio Results Dashboard 159
Figure 4-17 – High Regulatory Portfolio Results Dashboard 160
Figure 4-18 – Alternate High Regulatory Results Dashboard 161
Figure 4-19 – F.B. Culley 3 Co-Fire Portfolio Results Dashboard 162
Figure 4-20 – Delayed Reference Case Portfolio Results Dashboard 163
Figure 5-1 – Average CO_2e Emissions Intensity across 200 Draws 170
Figure 5-2 – Net Present Value of Revenue Requirements for All Portfolios 172
Figure 5-3 – Portfolio Exposure to Market Sales 173
Figure 5-4 – Portfolio Exposure to Market Purchases 174
Figure 6-1 – Alternate Reference Case Portfolios 180
Figure 6-2 – Alternate Reference Case Risk Analysis Scorecard 182
Figure 6-3 - Alternate Reference Case Preferred Portfolio Results Dashboard 183
Figure 7-1 - Implementation Schedule 191
Figure 8-1 - Heating Degree Days 194
Figure 8-2 - Cooling Degree Days 194
Figure 8-3- Total Peak Demand Requirements (MW), Including Losses and Street Lighting 197
Figure 8-4- Total Energy Requirements (GWh), Including Losses and Street Lighting 197
Figure 8-5- Residential Energy (GWh) 198
Figure 8-6- Commercial (GS) Energy (GWh) 198
Figure 8-7- Industrial (Large) Energy (GWh) 199

Figure 8-8- Historic Peak Demand 199
Figure 8-9- Historic Energy 200
Figure 8-10- Historic Annual Load Shape 200
Figure 8-11- Summer Peak Day 201
Figure 8-12- Typical Fall Day 201
Figure 8-13- Winter Peak Day 202
Figure 8-14- Typical Spring Day 202
Figure 8-15- January Load 203
Figure 8-16- February Load 203
Figure 8-17- March Load 204
Figure 8-18- April Load 204
Figure 8-19- May Load 205
Figure 8-20- June Load 205
Figure 8-21- July Load 206
Figure 8-22- August Load 206
Figure 8-23- September Load 207
Figure 8-24- October Load 207
Figure 8-25- November Load 208
Figure 8-26- December Load 208
Figure 8-27 - CEI South Cost Effectiveness Tests Benefits & Costs Summary 212
Figure 8-28 - 2025-2027 Approved Plan Gross kWh Energy Savings 213
Figure 8-29 - 2025 Electric DSM Operating Plan Program Savings 213
Figure 8-30 - 2026 Electric DSM Proposed Operating Plan Program Savings 214
Figure 8-31 - 2027 Electric DSM Approved Plan Program Savings 215
Figure 8-32 - Avoided Costs 216
Figure 8-33 - Coal Price Distribution (Nominal$/MMBtu) 218
Figure 8-34 - Natural Gas (Henry Hub) Price Distribution (Nominal$/MMBtu) 219
Figure 8-35 - Stochastic Inputs Energy Prices – Market Forecast 220
Figure 8-36 - CEI South Load Distribution (Megawatts) 221
Figure 8-37 - Lithium-Ion 100 MW/400 MWh Battery Storage Capital Costs Alternate Scenarios ($/kW) 223
Figure 8-38 - Solar Capital Costs Alternate Scenarios (100 MW) ($/kW) 223
Figure 8-39 – Solar plus Storage Capital Costs Alternate Scenarios (100 + 50 MW) ($/kW) 224
Figure 8-40 – Wind Capital Costs Alternate Scenarios (200 MW) ($/kW) 224
Figure 8-41 – 1x1 J Class Unfired CCGT Capital Costs Alternate Scenarios (620 MW) ($/kW) 225
Figure 8-42 – J Class SCGT Capital Costs Alternate Scenarios (426 MW) ($/kW) 225
Figure 8-43 – Advanced Nuclear (SMR) Capital Costs Alternate Scenarios (300 MW) ($/kW) . 226
Figure 8-44 – Portfolio Cost Rate (¢/kWh) 227
Figure 8-45 - Stakeholder Engagement Framework 231
Figure 8-46 - 2025 Stakeholder Meeting Schedule 233
Figure 8-47 - 2025 Tech-to-Tech Meetings 235
Figure 8-48 - Summary of Key Stakeholder Input 236
Figure 8-49 - DSM Oversight Board Meetings 237



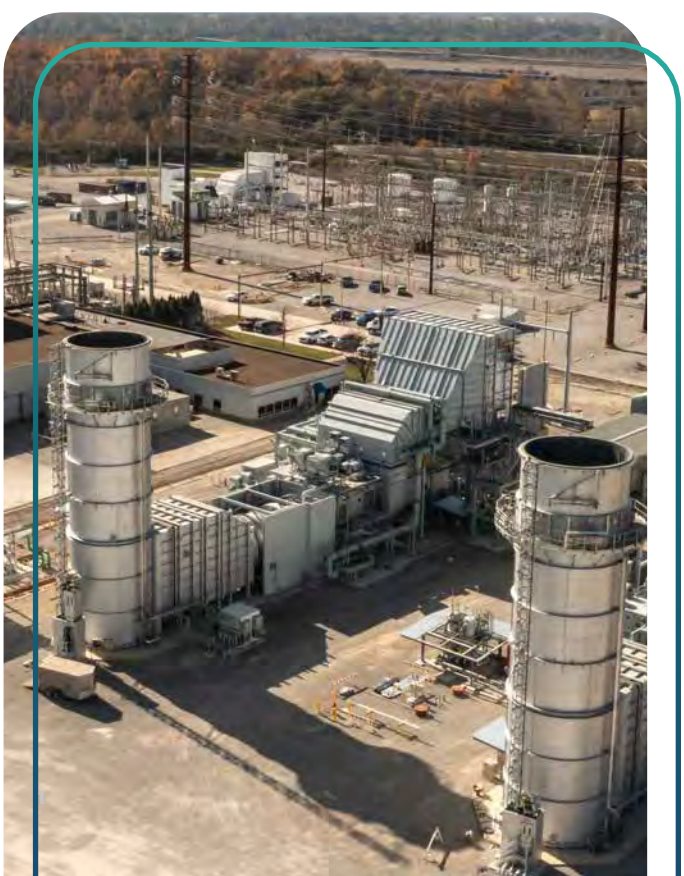
Executive Summary

(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.

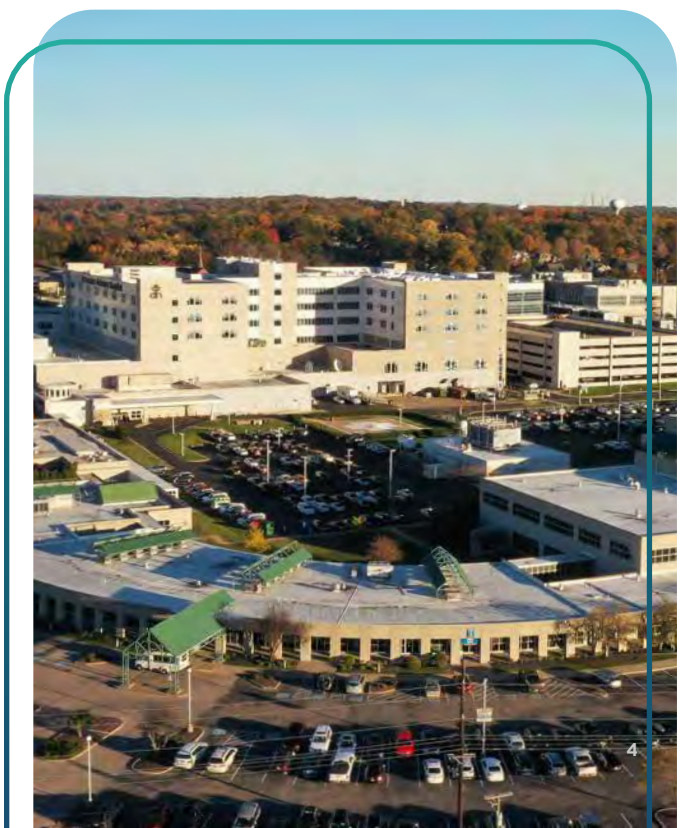
CEI South began its 2025 IRP process in early 2025 to explore new and existing supply-side and demand side resource options to reliably serve CEI South customers over the next 20 years. The Company's exploration included significant input and dialogue with stakeholders. While starting with our 2022/2023 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.





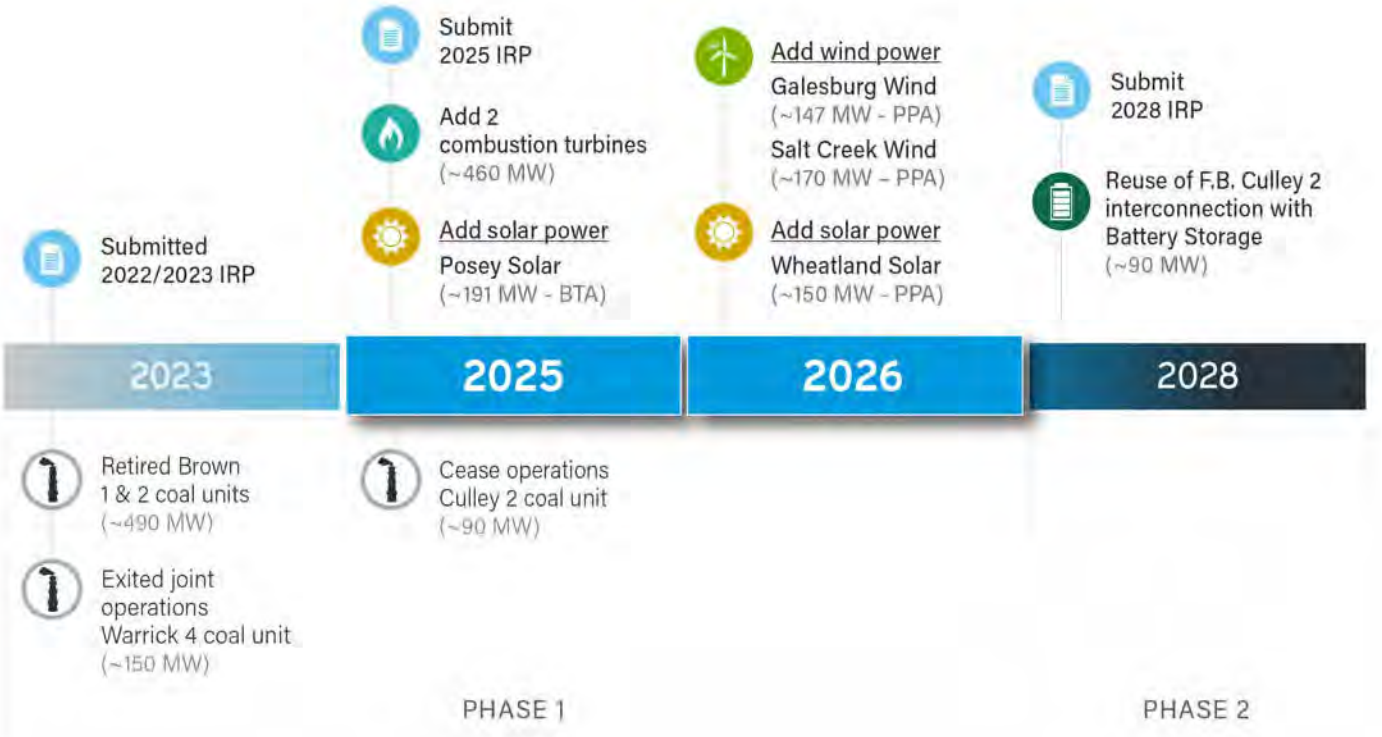
The alternate reference case maintains reference case market conditions but includes a potential large load addition that grows by 250 MWs per year, topping out at 1.5 GWs above CEI South's current retail load. This large load profile is indicative of ongoing discussions/ negotiations with prospective 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

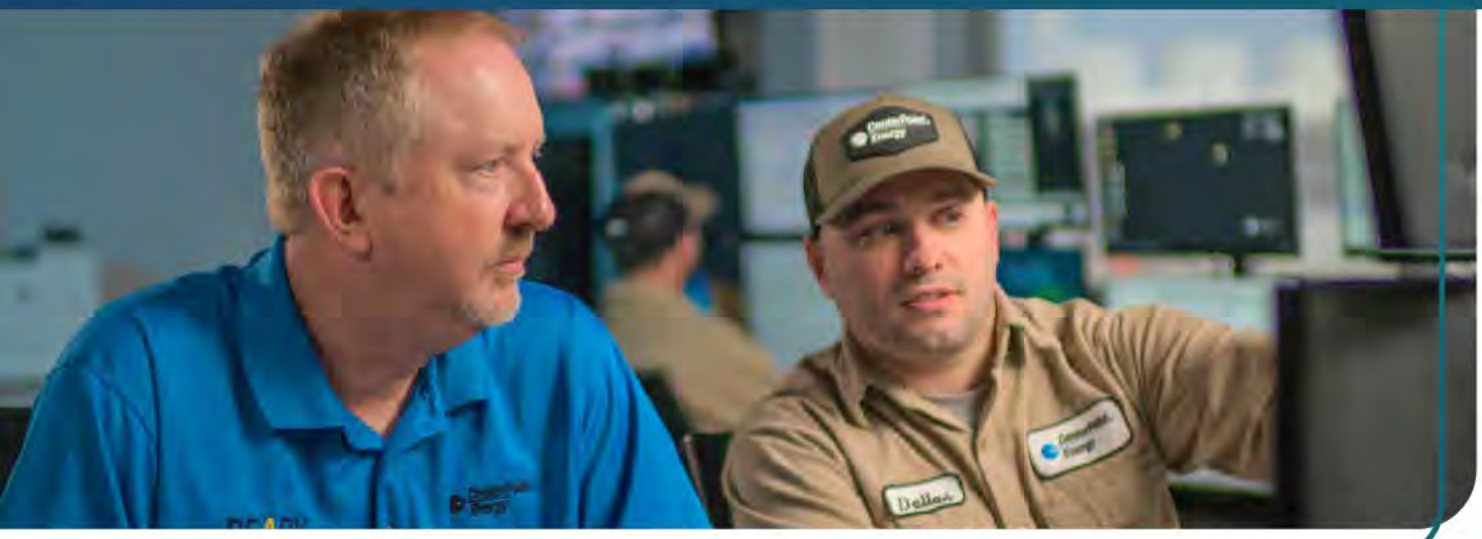


CEI South's Preferred Portfolio takes a more gradual approach to its generation transition, providing time for greater clarity amid today's unprecedented uncertainty. This approach also allows time for transmission system upgrades through CEI South's current TDSIC plan and the MISO's Long-Range Transmission 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**

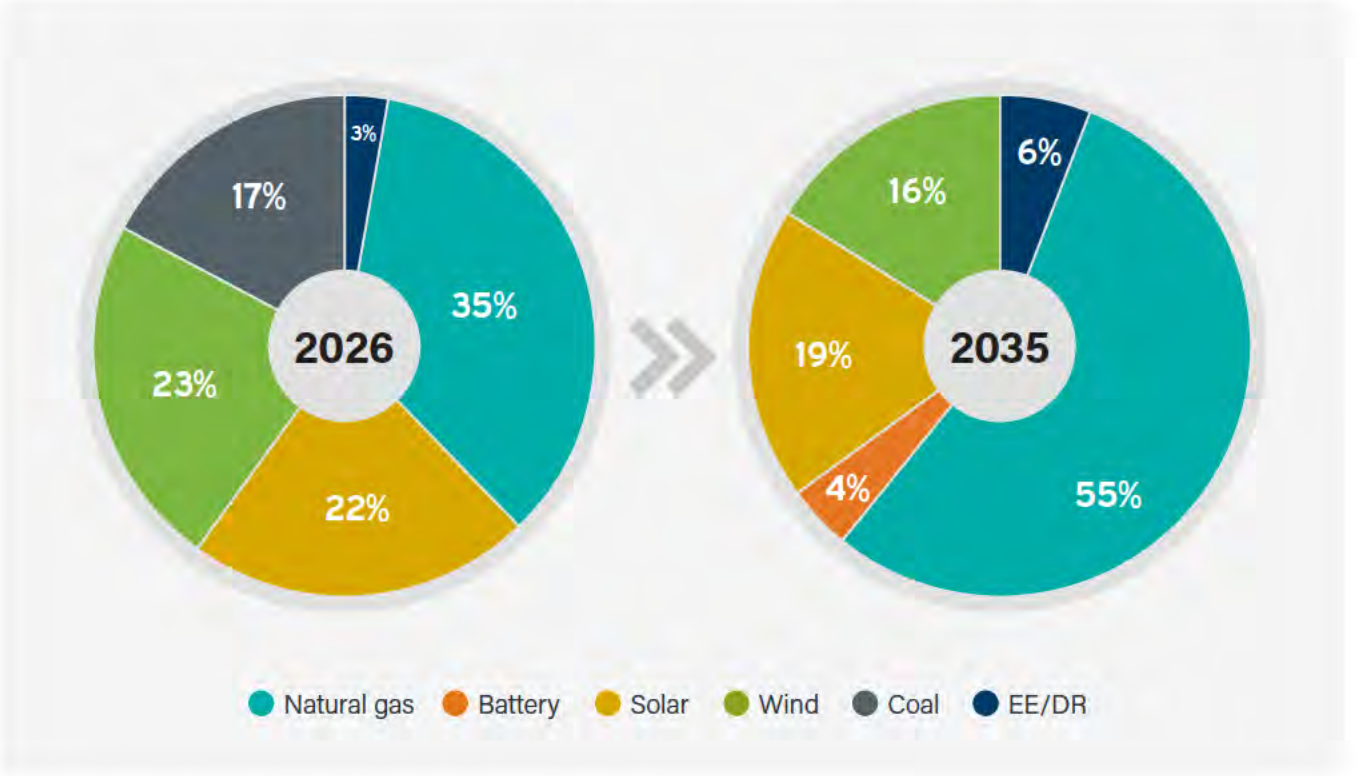
Between now and 2034, the Preferred Portfolio preserves the option to replace F.B. Culley 2 coal plant when it is suspended at the end of 2025 with a 90 MW battery storage unit by the end of 2028. CEI South will conduct another Request for Proposal ("RFP") to determine if the cost of this project has 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.

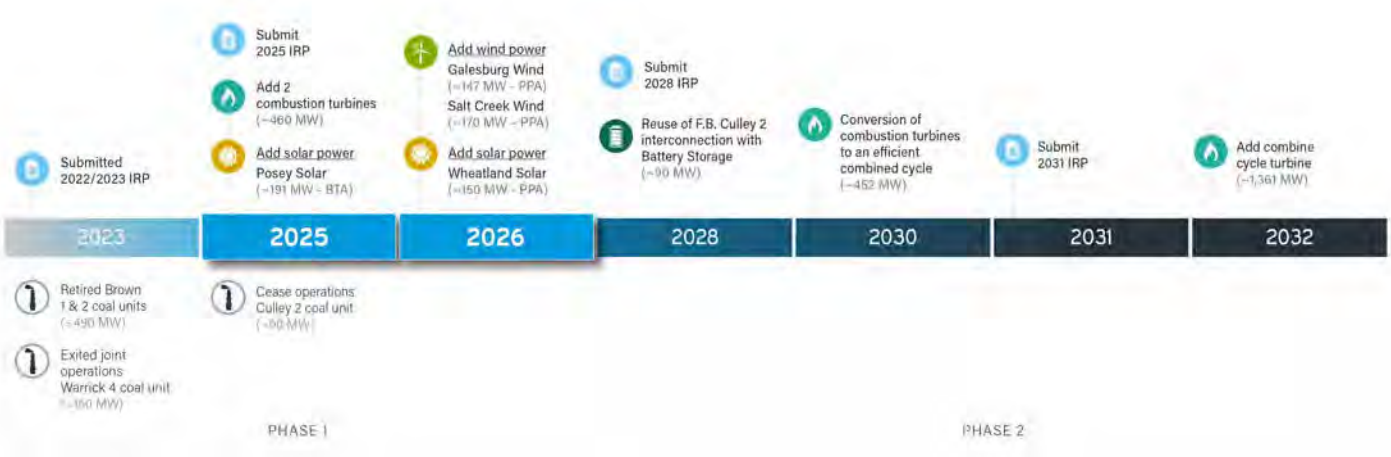
6. **Preserves tax base and jobs in Warrick County.** The replacement of F.B. Culley 2 with a battery storage system provides economic benefit to the community, whereas purchasing this needed capacity from the market does not. It is the equivalent of renting a home vs buying. Allowing F.B. Culley 3 to 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

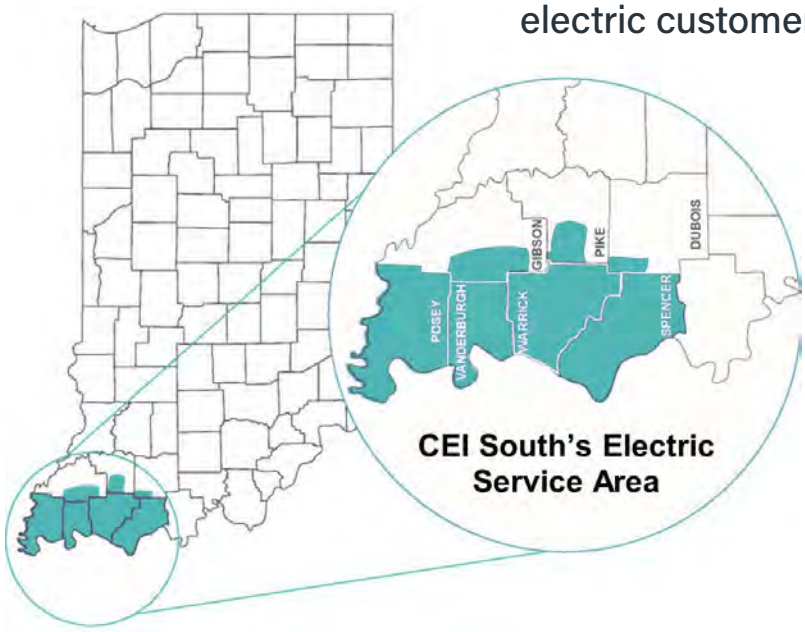
Provides energy delivery services to more than

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.

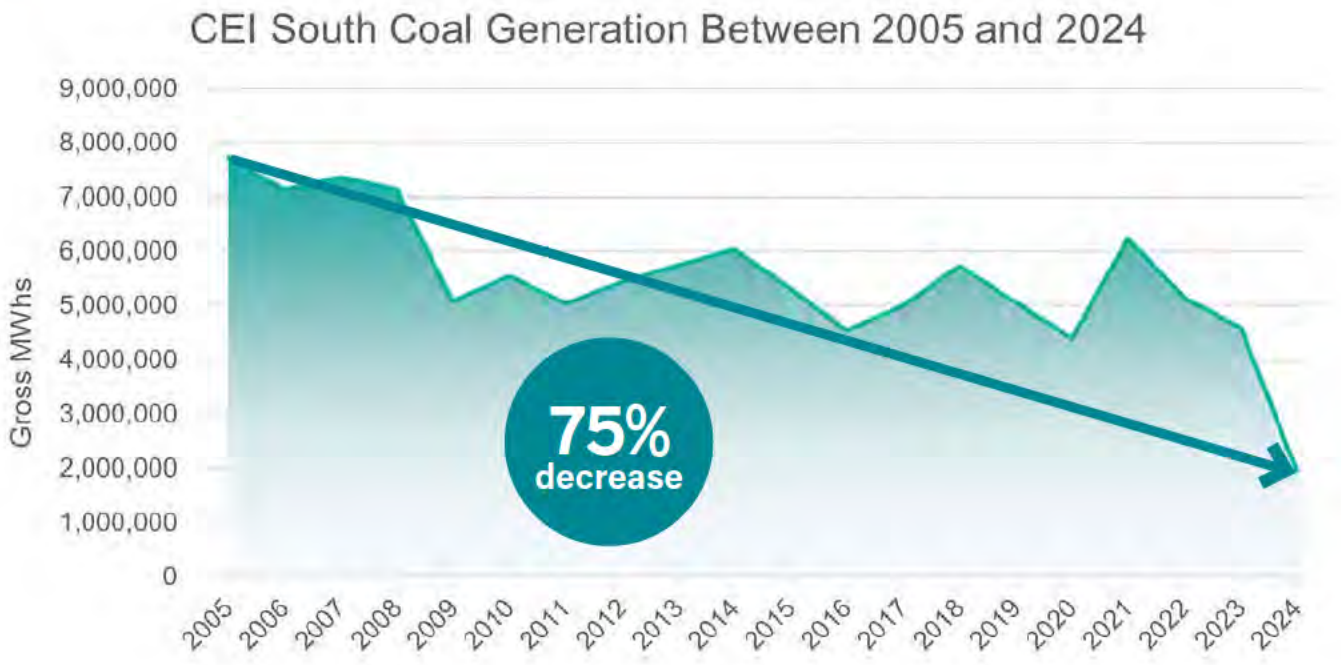


Unit [2]	Installed capacity ICAP (MW)	Primary Fuel	Unit in Service	Unit Retirement Date/Expiration	Unit Age	Coal Unit Environmental Controls [3]
F.B. Culley 2	90	Coal	1966	2025	59	Yes
F.B. Culley 3	270	Coal	1973	N/A	52	Yes
A.B. Brown 3	80	Gas	1991	N/A	34	
A.B. Brown 4	80	Gas	2002	N/A	23	
A.B. Brown 5	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.

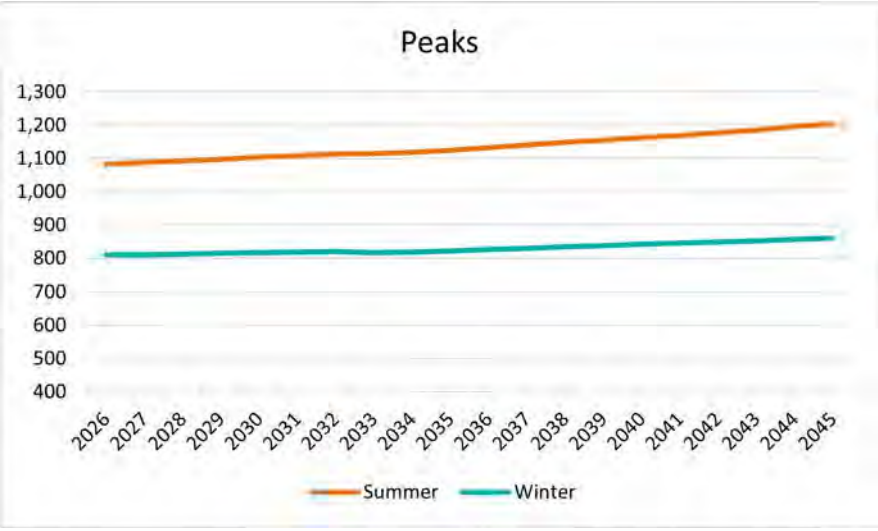
CEI South utilized direct feedback on analysis methodology, analysis inputs, and evaluation criteria from stakeholders, including but not limited to CEI South residential, commercial and industrial customers, regulators, elected officials, customer advocacy groups, trade associations and environmental 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.

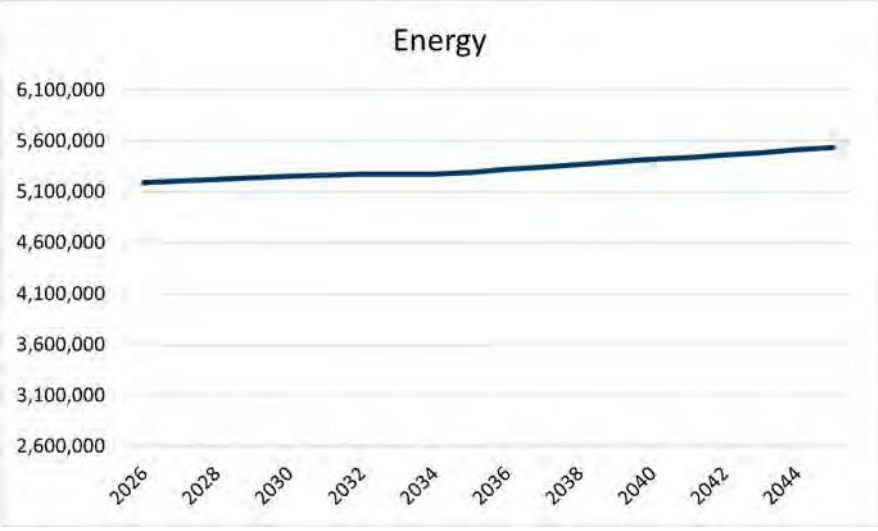
Customer Energy Needs

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





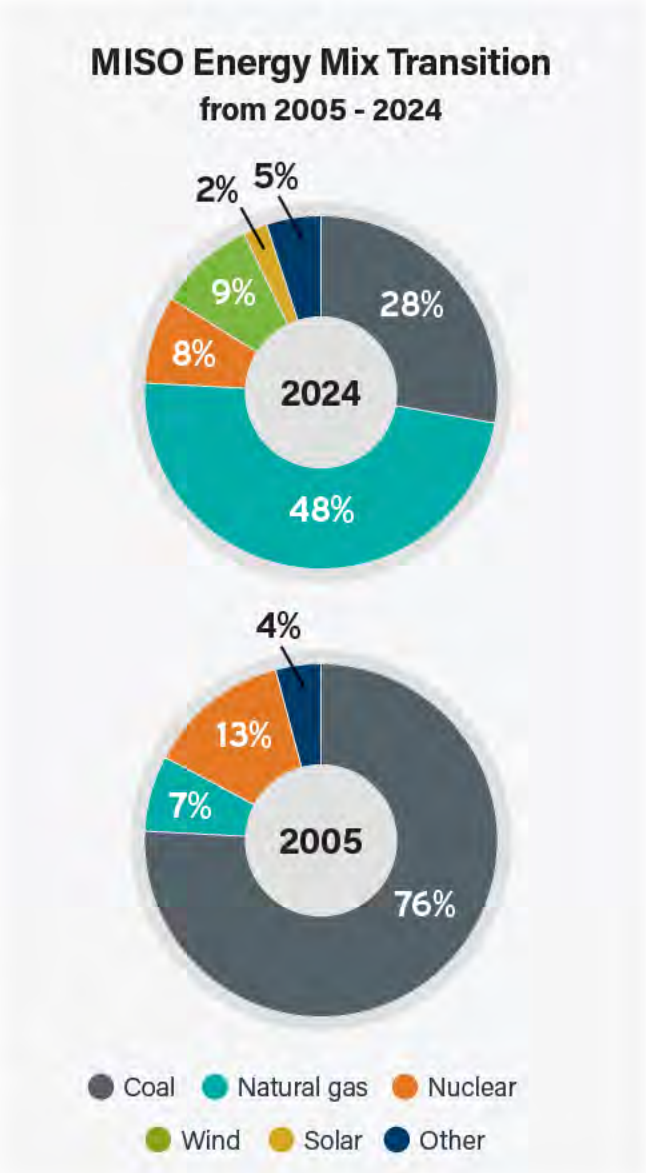


INDUSTRY TRANSITION

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.

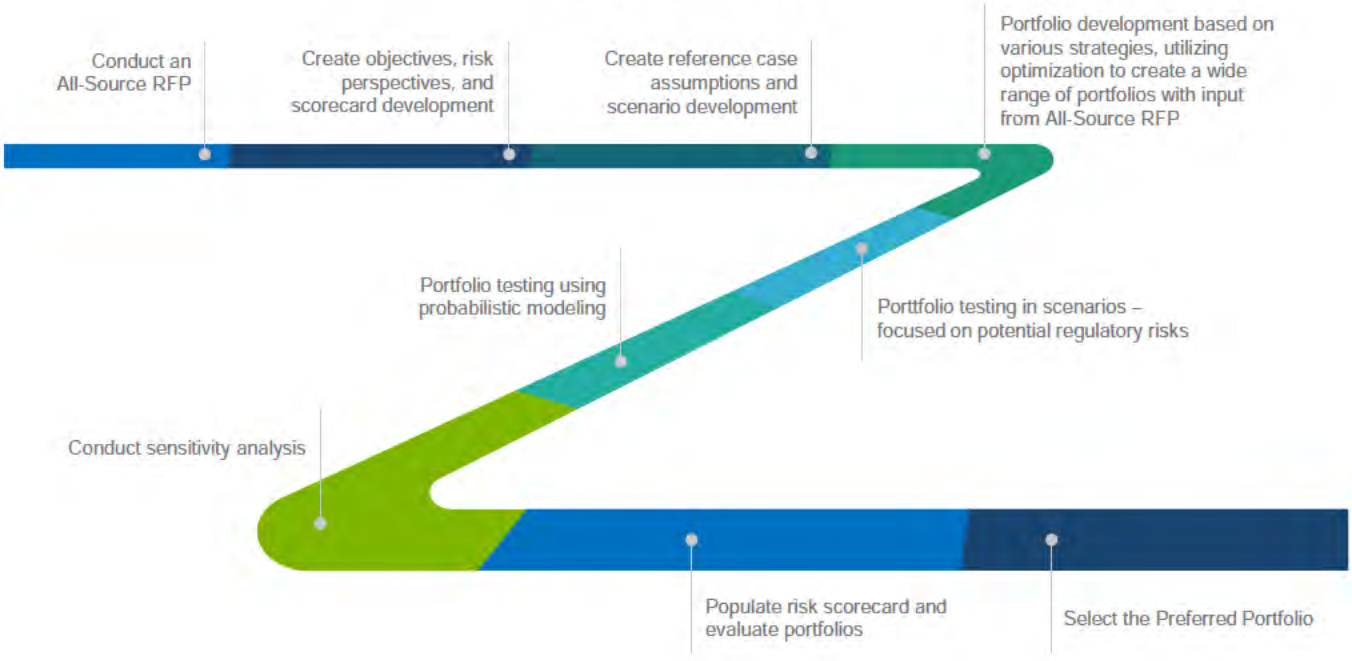


Analysis

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.

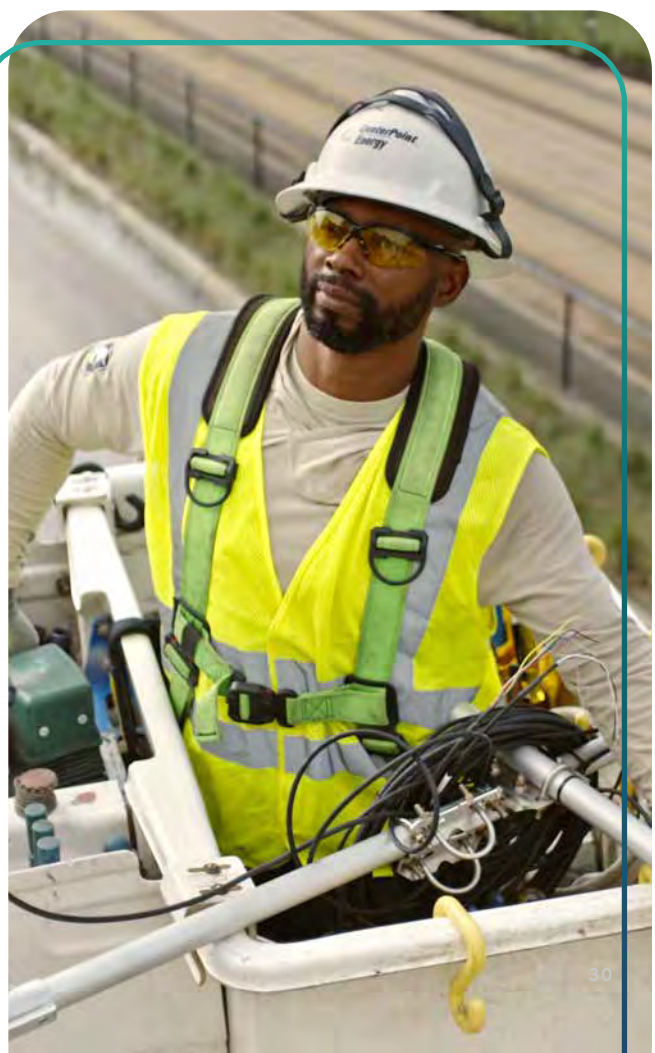
First, CEI South will continue to implement the generation transition that was identified in prior IRPs. CEI South is currently pursuing three renewable projects that are scheduled to be online in 2026: 147 MW Galesburg Wind (approved PPA), 150 MW Wheatland Solar (approved PPA), and 170 MW Salt Creek 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.





Integrated Resource Planning

Chapter 1

1.1. Integrated Resource Planning

CEI South takes integrated resource planning very seriously. The Integrated Resource Plan ("IRP") is used as a guide for how CEI South will serve existing and future customers over the next 20 years in a reliable, affordable, stable, resilient, and environmentally sustainable manner. The integrated resource plan sets the direction for future generation and Demand Side Management ("DSM") options; however, future analyses of changing conditions, filings and subsequent approvals from the IURC are needed to chart the specific course.

CEI South is required to submit its IRP to the IURC every three years and last submitted it in 2023 with a plan to transition its generation fleet away from a majority reliance on coal to a portfolio of renewable generation, supported by a diverse set of natural gas generation resources. Since that time two new quick start, fast ramping natural gas combustion turbines and the Posey Solar project have come on-line, while the conversion of F.B. Culley 3 to natural gas was paused for re-evaluation within this IRP, and several renewable projects were canceled due to increasing cost.

With a focus on stakeholder input, CEI South began the 2025 IRP process by gathering feedback from stakeholders on the last IRP and the Director's Report for the 2022/2023 IRP. Additionally, CEI South worked closely with IRP stakeholders throughout the process, including multiple tech-to-tech discussions and information sharing between public stakeholder meetings, as discussed in Section 8.6 Public Advisory Process.

Although the future remains uncertain; several factors have set the stage for the 2025 analysis. After many decades of stagnant growth, reindustrialization and the Artificial Intelligence ("AI") race has changed the trajectory and will require a significantly larger supply of around-the-clock, reliable, and uninterrupted power in the near-term. Renewable resources have been slow to come online, many of which are not projected to come on-line at all due to higher than projected interconnection costs, delays in the MISO queue, tariffs, declining accreditation from MISO, changes to state and federal policy, the proposed repeal of EPA greenhouse gas regulation, and the passage of the One Big Beautiful Bill Act ("OBBBA") that accelerated the sunset of IRA tax credits to wind and solar resources.

Despite considerable uncertainty throughout the IRP development, CEI South has remained agile in navigating evolving risk, including but not limited to incorporation of stakeholder feedback on methodology, modeling, and assumptions, adding two additional scenarios per stakeholder feedback, and updating originally proposed scenario assumptions in near real time to account for proposed changes in EPA regulation. This necessitated requesting and receiving approval for an extension to submit the IRP on or before December 5, 2025.

1.1.1. Indiana's Five Pillars

On April 20, 2023, House Enrolled Act 1007 was signed into law by Governor Eric J. Holcomb. Indiana incorporated the Five Pillars of Indiana energy policy into state law in Indiana Code 8-1-20.6, with an effective date of July 1, 2023. The law states that decisions concerning Indiana's electric generation resource mix, energy infrastructure, and electric service ratemaking constructs must consider the following attributes: reliability, resiliency, stability, affordability, and environmental sustainability. The Indiana Utility Regulatory Commission adopted General Administrative Order ("GAO") 2023-04, which was inclusive of IRPs.

The Five Pillars are Reliability, Resiliency, Stability, Affordability, and Environmental Sustainability. Each has been considered equally within this IRP and are defined below:

Figure 1-1 – Five Pillars



To better account for the five pillars, CEI South structured its portfolio scorecard, a tool to help evaluate risk and tradeoffs, by aligning measures with each of the pillars to aid in the selection of a Preferred Portfolio. While affordability often takes center stage, each pillar is essential in shaping a comprehensive energy strategy. Under the lens of the five pillars, CEI South included the following scorecard updates:

- Incorporated a view into near-term affordability with the inclusion of an energy burden analysis. This complements the traditional long-term affordability measures;
- Conducted a more in-depth evaluation of reliability, resilience, and system stability in this IRP through a dedicated transmission analysis, which informed the development of additional scorecard measures; and
- Enhanced its view into environmental sustainability by adding additional air measures into the scorecard.

1.1.2. State of the World

Over the last year and a half, there has been unprecedented change that directly effects resource planning, including but not limited to:

- Updates to how resources will be accredited to meet reliability requirements,
- Updates to greenhouse gas regulations from the EPA,
- Escalating costs for various resources,
- Policy changes on the state and federal levels,
- Increasing load for the first time in decades, and
- Change in the regulatory environment.

Changes like these have escalated in recent years. Utilities typically face one or two major challenges per planning cycle. These risks demand careful mitigation to ensure the selected resource portfolio remains flexible and capable of adapting to an uncertain future. CEI South and other utilities across the country are required to make long-term planning decisions in a way that mitigates all of the risks that present themselves. This cycle is particularly challenging with at least 6 major unresolved issues, each of which presents a different risk.

1.1.3. Generation Transition (MISO)

MISO is in the midst of a significant transformation in how it plans for and accredits capacity, reflecting both the rapid transition of the generation fleet and the increasing level of system risk. In 2023, MISO shifted from an annual construct to a Seasonal Accredited Capacity (“SAC”) framework, requiring utilities to demonstrate sufficient accredited resources in all four seasons. This shift recognizes that reliability risks no longer occur only in the summer season. Growing penetrations of solar and wind, shoulder-season maintenance outages, and evolving demand patterns have increased exposure to non-summer season peaks. Seasonal planning introduces more precision into capacity

accreditation and compels utilities to build portfolios resilient to reliability challenges year-round.

Looking ahead, MISO is also preparing to replace its current accreditation methods with a more probabilistic approach based on Direct Loss of Load (“DLOL”) modeling. This proposed framework, expected to take effect in the 2028/2029 Planning Year, will assign capacity value to resources based on their performance in avoiding loss-of-load events rather than static assumptions. It builds upon traditional Loss of Load Expectation (“LOLE”) analysis but offers finer granularity by considering not only the probability of shortfall but also the contribution of each resource type in mitigating it. For utilities, the transition means that intermittent resources such as wind and solar will receive capacity credit more directly tied to their effective reliability contribution, while fast-start and dispatchable resources may become even more valuable.

Alongside the move to seasonal and probabilistic accreditation, MISO is also advancing changes in how the Planning Resource Auction (“PRA”) clears capacity through the introduction of the Reliability Based Demand Curve (“RBDC”). The RBDC links capacity prices directly to reliability outcomes by steepening the demand curve as the system approaches shortfall conditions. In effect, it values incremental capacity more highly when the system is at risk, sending stronger price signals for new entry and retention of resources that support reliability. By aligning market prices more closely with the reliability value of capacity, RBDC is designed to help ensure sufficient investment while avoiding undue reliance on emergency procedures.

At the same time, the generation interconnection queue is undergoing substantial reform. With thousands of megawatts of renewable and storage projects proposed, MISO has adopted new cluster-based study processes, standardized timelines, and cost allocation reforms to accelerate development while maintaining fairness and reliability. These reforms are intended to reduce backlog, improve transparency, and align new resource development with regional transmission expansion.

Taken together, the seasonal construct, evolving probabilistic accreditation, implementation of RBDC, and queue reforms reflect the broader generation transition underway in MISO. The system is moving away from static, one-size-fits-all capacity rules toward more dynamic, risk-informed approaches that account for the realities of a rapidly changing resource mix. For utilities like CEI South, these changes require close monitoring and integration into planning processes to ensure that portfolios not only meet today’s requirements but remain reliable and compliant under tomorrow’s market rules.

1.1.4. Political and Regulatory Environment

Since the last IRP, significant shifts have occurred at both the federal and state levels, including the election of Donald J. Trump as President of the United States and Mike Braun as Governor of Indiana.

President Trump immediately rescinded executive orders issued during the Biden administration and replaced them with new directives aligning with his administration's policy agenda. Speaking in broad strokes, these changes were intended to unleash American energy dominance, paving the way to keep existing fossil generation on-line and to put in place barriers to renewable energy generation.

Along with the flurry of executive orders, President Trump signed the OBBBA into law. With his signature, this bill set into motion the core of President Trump's tax and spend agenda. It has had far reaching impacts throughout the energy industry and integrated resource planning. The law rolls back tax incentives for those that purchase electric vehicles, which could have an effect on load projections in the long-term. Additionally, the bill rapidly phases out Inflation Reduction Act ("IRA") tax incentives for wind and solar resources, while nuclear and battery resource provisions from the IRA were largely preserved.

President Trump has also brought in a new era of tariffs in an effort to bring back lost manufacturing by leveling the playing field with foreign countries. While tariffs could bring more load back to the system in the long run, near-term uncertainty and inflation have had the effect of raising costs for new generating resources, often built with materials sourced from all over the world.

Finally, President Trump has worked to appoint those that will promote his agenda through government agencies. These agencies have made shifts that must be accounted for within the IRP, most notably, the potential roll-back of EPA greenhouse gas regulations could ease restrictions on fossil-fueled dispatchable resources needed to support the administration's desire for dominance in Artificial Intelligence.

Although Governor Braun's election has not yet resulted in policy shifts as sweeping as those at the federal level, several notable developments in Indiana warrant attention. Governor Braun is also supportive of maintaining existing fossil fuel generation to support economic development opportunities, and he is a strong proponent of building small modular nuclear reactors in Indiana by the early 2030's. To carry out his energy agenda to ensure affordable and reliable power for current residents and economic development opportunities, Governor Braun named Suzanne Jaworowski Secretary of Energy and Natural Resources. In her position, she oversees the Indiana Department of

Environmental Management, the Indiana Regulatory Commission, the Office of Utility Consumer Counselor, and several other agencies.

In August, Governor Braun named long-time utility consumer advocate Abby Gray as Utility Consumer Counselor and directed her find ways to lower bills for Hoosiers. Additionally, Governor Braun will soon be appointing three new Commissioners to the IURC.

1.1.5. Environmental Regulations

In June of 2025, EPA proposed to rescind greenhouse gas limits for new and reconstructed gas turbines and existing and modified coal fired generating units under Clean Air Act Sections 111(b) and (d). As an alternative, the proposal would withdraw a previous determination that carbon capture and storage is commercially available and cost effective to reduce greenhouse gas emissions. This change had a major effect on modeling assumptions within the current IRP, as the ultimate finalization of either option would rescind the drivers for retirement of uncontrolled (for CO_2) units by 2032. While this is still a proposal, the proposal is an action in response to the Administration's Executive Order 14154, "Unleashing American Energy", which directs EPA to identify rules that "impose an undue burden" on domestic energy resources. CEI South believes that the current requirements applicable to GHG's under 111(b) and (d) will not be the most likely future regulatory scenario and therefore updated its Reference Case. Ultimately, the proposed rule revisions will be litigated, and a new proposal could come from a future administration. CEI South developed scenarios to account for these future regulatory uncertainties and potential boundary conditions.

1.1.6. Large Loads

With the rise of AI data centers and onshoring of industry, the country is facing rapid electric growth that has not been seen in decades, if ever. Depending on the project, these loads can start large and scale very quickly, some of which grow to be larger than a mid-sized city such as Evansville, IN. CEI South has fielded many economic development inquires over the last two years, several of which fit this mold.

As part of this IRP, CEI South initially planned a large load sensitivity that evaluated possible build outs based on conversations. However, stakeholders were understandably very interested in this topic given the implications for our system. In response, CEI South agreed it was prudent to develop a separate scenario to address this realistic possibility. As a result, CEI South built an Alternate Reference Case to evaluate the best path forward should an agreement be reached with a potential large load addition.

1.1.7. CenterPoint Energy Rate Case and Community Engagement

In December of 2023, CEI South filed its first rate case in 14 years. Ultimately, a settlement was approved, increasing revenues by $80 million dollars. The increase was approved to be phased in over a year between February 2025 and March 2026, with the largest increase coming in the summer of 2025 as the Posey solar plant and the first of the two new combustion gas turbines (A.B. Brown unit 6) came on-line. 80% of the requested increase was associated with these generation units, including unit 5, which came online in August. Customer affordability was a key issue throughout the case with our customers and their advocates. With affordability top of mind, CEI South worked to evaluate the bill impact of various portfolios in the near to mid-term, as well as evaluating the long-term affordability of each portfolio. Ultimately, near to mid-term affordability proved to be one of the key differentiators in the selection of the 2025 Preferred Portfolio.

To strengthen communication with customers, CEI South hosted an initial round of Community Connect sessions across its service territory. These events offered customers the opportunity to engage directly with CenterPoint employees about key investments aimed at improving system reliability and enhancing bill transparency. Subject matter experts were on hand to answer questions and address concerns related to CEI South's long-term planning and the IRP Preferred Portfolio. Dates and times of the Community Connect sessions are listed in the table below.

Figure 1-2 – Community Connect Sessions

DATE	TIME	LOCATION
Thursday, 11/6	4 - 7 p.m.	**South Spencer High School** 1142 N. County Road 275 W., Rockport, IN
Saturday, 11/8	9 a.m. - noon	**Vanderburgh County 4H Fairgrounds** 201 E. Boonville-New Harmony Road, Evansville, IN
Wednesday, 11/12	4 - 7 p.m.	**Mount Vernon Junior High School** 701 Tile Factory Road, Mount Vernon, IN
Thursday, 11/13	4 - 7 p.m.	**CK Newsome Community Center** 100 E. Walnut Street #1, Evansville, IN
Saturday, 11/15	9 a.m. - noon	**Ohio Township Phoenix Event Center** 3433 Libbert Road, Newburgh, IN

1.1.8. CEI South Current Generation Portfolio

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.

Figure 1-3 – CEI South Generating Units

Unit[6]	Installed Capacity ICAP (MW)	Primary Fuel	Unit in Service	Unit Retirement Date / Expiration	Unit Age	Coal Unit Environmental Controls[7]
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	232	Gas	2025	N/A	<1	
A.B. Brown 6	232	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	2025	N/A	N/A	
Salt Creek	170	Wind PPA	2025	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	

1.1.9. Status on Implementing Prior IRP (Retirements and Additions)

Since the last IRP filing, CEI South has encountered significant challenges in moving forward with key pieces of the last two IRP Preferred Portfolios. First, several renewable projects have been terminated due to market dynamics that caused prices to escalate beyond what the Commission approved and beyond where CEI South believed to be affordable for its customers. 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

[6] CEI South has a 1.5% ownership share of Ohio Valley Electric Corporation ("OVEC") which equates to approximately 32 MW.

[7] Both Coal units are controlled for Sulfur Dioxide ("SO_2"), Nitrogen Oxide ("NO_X"), Particulate Matter (dust), and Mercury. F.B. Culley 3 is controlled for Sulfur Trioxide ("SO_3") and Sulfuric Acid ("$H2S0_4$").

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 similar upward pricing pressure; after years of negotiation and a re-evaluation of this project in this IRP, CEI South opted to walk away from this project in an effort to keep customer rates as affordable as possible.

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. At that time, the Preferred Portfolio in CEI South's previous 2022/2023 IRP concluded that a generation transition with the conversion of F.B. Culley 3 from coal to natural gas, along with DSM, wind, and solar resources was the optimal path forward. CEI South began implementing this 2022/2023 IRP by filing two cases seeking approval for (1) signed purchase power agreements ("PPA") for two 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, this IRP affirms the direction taken by CEI South. These renewable resources still qualify for Federal incentives, which dramatically lowered the cost of these renewable resources relative to what could be acquired in the future, post elimination of IRA tax incentives for wind and solar resources.

In preparation for retirement, CEI South submitted an Attachment Y to MISO to suspend operations of its smallest, least efficient coal unit, F.B. Culley 2. This unit is slated for suspension at the end of 2025. A key decision in this IRP was to determine how to replace this unit and whether or not to preserve the existing interconnection to the grid. CEI South will have approximately three years to replace the unit, preserving the interconnection. Options that were available and evaluated were small gas units or battery storage.

1.1.10. Culley 3 Conversion

In the last IRP, CEI South selected a Preferred Portfolio that converted F.B. Culley 3, a 270 MW coal plant, to natural gas by 2027. Given the inputs and likely potential future at that time, this was a competitive option. In light of growing change and uncertainty, CEI South chose to pause its conversion plans and opted not to pursue a Certificate of Public Convenience and Necessity from the Indiana Utility Regulatory Commission at this time. CEI South chose to re-evaluate the F.B. Culley conversion with renewables within this IRP. While the F.B. Culley coal-to-gas conversion may become a viable option in the future, current analysis indicates it is not projected to be cost-effective. As detailed later in this IRP, a conversion paired with renewables is projected to be approximately 14% more expensive than the Preferred Portfolio.



Resource Planning Process

Chapter 2

2.1. Planning Structure

CEI South's IRP was developed using a structured, data-driven planning process that incorporates real-world operating conditions, market signals, stakeholder input, and long-range policy and technology expectations. While uncertainty remains a fundamental characteristic of long-term planning, CEI South's objective is to develop a portfolio that is resilient across a wide range of plausible futures while maintaining affordability, reliability, environmental sustainability, stability, resilience, and operational feasibility. The IRP process is organized around five major planning steps:

1) **Real-World Inputs and Modeling Foundations** – Establishing accurate load forecasts, technology costs, demand-side potential, resource data, and fuel assumptions, supported by market solicitations and expert consultation.
2) **Development of Resource Strategies and Planning Scenarios** – Structuring candidate resource strategies, evaluating transmission deliverability, and modeling a range of policy and demand futures.
3) **Planning Priorities and Guiding Principles** – Defining the core decision-making values that shape portfolio evaluation, supported by stakeholder perspectives and long-term CEI South objectives.
4) **Comprehensive Portfolio Development & Testing** – Using a suite of planning tools to simulate long-term portfolio performance, test sensitivities, and assess operational and financial tradeoffs.
5) **Portfolio Evaluation** – Comparing portfolios using a structured framework aligned with CEI South's long-term planning priorities.

The remainder of this section outlines each step in more detail, highlighting the analytical foundation that supports the Preferred Portfolio selection later in the IRP.

2.2. Real-World Inputs and Modeling Foundations

In Q2 2024, CenterPoint launched an open All-Source Request for Proposals ("RFP") (*Technical Appendix Attachment 2.1 2024 All-Source Request for Proposal*) to solicit capacity and energy resource options from the market, including specifically requesting options to replace the F.B. Culley 2 generator and reuse the existing transmission interconnection. This broad solicitation was essential for capturing current, technology-specific costs and operational characteristics. The 2024 All Source RFP yielded a diverse set of project proposals, including renewables, storage, thermal resources, and demand-side offerings. These responses informed both near-term procurement strategies and were also translated into representative long-term modeling inputs.

In addition to the All-Source RFP, CEI South worked with 1898 & Co. to conduct a detailed technology assessment (*Technical Appendix Attachment 2.2 2025 Technology Assessment Summary (Confidential)*) to support the evaluation of a wide range of

resources and to supplement the All-Source RFP. Resource-specific cost assumptions were based on a combination of historical operations data and forward-looking financial models. Fixed and variable O&M, depreciation, book life, and capital recovery factors were incorporated to reflect the true economic impact of maintaining or replacing legacy assets. Each resource type was reviewed for cost, performance, availability, and operational viability, which informed the resources that were included in modeling.
CEI South continued its long-standing partnership with Itron, a recognized leader in energy forecasting to produce 20-year energy and demand forecasts. The resulting load forecasts incorporated recent trends in fleet electrification, trended weather, customer behavior, economic growth, customer-owned rooftop solar, and appliance efficiency. This foundational input was used across all planning scenarios.

To evaluate the long-term potential of customer energy savings, CEI South worked with GDS Associates to conduct a comprehensive Market Potential Study (*Technical Appendix Attachment 3.6 2025 DSM Market Potential Study*) focused on demand-side management ("DSM"). The study assessed achievable impacts across the planning horizon by analyzing customer segmentation, end-use technologies, cost-effectiveness, and adoption potential. These results were integrated into portfolio modeling to reflect Demand Response ("DR") and Energy Efficiency ("EE") as resource options on a consistent and comparable basis with supply-side alternatives.

Supporting these major studies was a rigorous data development effort. CEI South used publicly available datasets, averaged confidential vendor information in order to incorporate multiple perspectives and to allow for public viewing, and internal data to populate a robust suite of assumptions. For instance, CEI South utilized industry forecasts for natural gas and other fuels, including NYMEX futures, third-party consultant projections, and public sources such as the EIA. These assumptions were scenario-specific and reflected differing regulatory environments and market conditions.

This work helped ensure that resource modeling was grounded in transparent and realistic expectations.

2.3. Development of Resource Strategies and Planning Scenarios

CEI South developed a set of generation strategies to reflect plausible pathways based on CEI South's existing fleet, known constraints, and evolving regulatory and market dynamics. For example, as part of evaluating the future of existing coal-fired generation, CEI South modeled multiple resource conversion and replacement strategies to test how the system responds to retirement timing, capacity shortfalls, and differing replacement technology mixes.

These deterministic generation strategies served as a foundational planning step, representing different strategic postures. Some explored early retirement and rapid decarbonization; others maintained legacy assets longer to evaluate affordability or for fuel diversity. To support this process, CEI South created several fixed resource configurations, including storage options, new gas replacements, continuation of existing resources, conversion of existing resources, and renewable heavy alternative, to observe how the capacity expansion model responded. These “what-if” inputs were used to test the system’s flexibility and better understand which technologies filled capacity gaps most effectively under different assumptions.

In parallel, CEI South initiated a transmission study (*Technical Appendix Attachment 2.3 Transmission Study (Confidential)*) to examine the deliverability, reliability, and cost implications of these generation strategies. This was a critical component of planning, as the viability of new generation, especially renewable resources, often depends on transmission availability and local system limitations. Transmission constraints, upgrade needs, and regional challenges were modeled alongside generation expansion to ensure that the resulting portfolios were not only economically viable but also physically feasible on an electric transmission basis. The findings from the transmission study were used to:

- Identify system constraints that might require upgrades or lead to curtailment risks;
- Quantify the cost of transmission upgrades associated with portfolio sensitivities; and
- Refine resource strategies and modeling assumptions where needed.

This integration of transmission and generation modeling ensured that resource portfolios were built on a technically sound foundation, which attempts to minimize the risk of stranded assets or overlooked system limitations.

2.4. Stakeholder Engagement

Stakeholder engagement is a cornerstone of integrated resource planning, as input is shared on all portions of the analysis. The stakeholder process functions as a collaborative forum – providing a diverse range of views with multiple opportunities to provide input on the assumptions, inputs, and methodologies to inform CEI South’s IRP development. Over the past twelve months, CEI South has provided many engagement opportunities to a diverse audience of CEI South customers, regulators, customer advocacy groups, environmental advocacy groups, fuel suppliers and advocacy groups, shareholders, economic development groups, generation developers, and elected officials. Throughout the 2025 IRP, stakeholders were encouraged to engage and participate in the development of the Integrated Resource Plan. Engagement opportunities included public meetings, technical meetings, and direct communication

channels via CEI South's IRP website and the IRP-specific email address, irp@centerpointenergy.com. CEI South has also engaged in written correspondence in response to data requests from several stakeholders.

CEI South hosted four public meetings in Evansville, Indiana – with in-person and virtual participation options (Figure 2-1). An average of 70 individuals, representing over 30 organizations, registered for the public meetings. Meeting agendas focused on a broad range of IRP topics, including the overall process, timelines, impactful industry factors, resource evaluations, modeling inputs and methodologies, scenarios and sensitivities. To ensure ample opportunity for stakeholder feedback and questions, Q&A touchpoints were scheduled throughout each meeting. Public meeting presentations and summaries were shared with stakeholders on CEI South's IRP website, www.centerpointenergy.com/irp.

Figure 2-1 – 2025 Stakeholder Meeting Schedule



In addition to public meetings, CEI South hosted three technical meetings. These meetings included detailed and often confidential discussions of modeling inputs and assumptions. Interested stakeholders, with a signed NDA, were able to participate in the technical meetings as well as access confidential modeling data provided throughout the process through a secure file share site. These meetings offer a forum to discuss detailed assumptions and evaluation criteria to gain insight from multiple perspectives.

Section 8.6, Public Advisory Process, further details CEI South's public engagement, including a robust description of the process, key issues discussed, stakeholder feedback, data requests and stakeholder impact on the development of the IRP.

2.5. Planning Scenarios

To ensure CEI South's Preferred Portfolio performs reliably under a broad range of future conditions, the IRP includes a suite planning scenarios. Each scenario reflects a distinct

"worldview" shaped by key uncertainties in environmental regulation, load growth, technology costs, fuel markets, and federal policy implementation. Together, they test the durability of candidate portfolios across plausible futures rather than anchoring planning decisions to any single forecast.

These scenarios share a consistent modeling foundation, using the same optimization tools, reliability targets, and engineering constraints, but differ in the external forces shaping utility operations. This framework allows CEI South to explore how shifts in demand, policy, and market conditions could alter resource needs, economic outcomes, and implementation feasibility.

2.6. Reference Case

The Reference Case represents CEI South's best estimate of future conditions and serves as the baseline for portfolio development and scenario evaluation. It reflects current law along with recent policy developments, specifically, developments in the proposed repeal of carbon regulation and modified elements of certain Inflation Reduction Act ("IRA") provisions. These assumptions were selected to reflect CEI South's planning judgment about the most likely regulatory, market, and economic trajectory over the 20-year horizon. To develop this scenario, CEI South worked with 1898 & Co. and other technical consultants to establish consistent and transparent assumptions across all major inputs:

- **Load Forecast:** CEI South's long-term energy and demand forecast was developed by Itron and reflects residential, commercial, and industrial usage patterns. It incorporates appliance efficiency trends, fleet electrification, long-term weather normalization, continued expansion of customer owned solar panels, and modest economic growth across the service territory.
- **Fuel Prices:** The Reference Case uses a consensus forecast approach for natural gas and coal, averaging inputs from sources such as S&P Global, Wood Mackenzie, Hitachi, and EVA. This reduces bias from any single forecast and reflects a transparent, market-aligned view of future commodity prices.
- **MISO Capacity Prices:** Scenarios include a forecast of MISO Zone 6 capacity prices, based on available projections from Hitachi, S&P Global, and Wood Mackenzie. These help inform portfolio revenue requirements and cost competitiveness resource portfolios, whether buying or selling excess capacity[8].

[8] Note that portfolios were not able to sell capacity in capacity expansion modeling runs. This helped prevent building more resources than needed for the purpose of selling capacity into the market.

- **CO_2 Price Proxy:** With the proposed repeal of Environmental Protection Agency ("EPA") Clean Air Act ("CAA") 111, the Reference Case only includes costs for compliance upgrades under framework modeled a proxy utilizing the Affordable Clean Energy ("ACE") Rule for existing coal resources, providing an efficiency requirement without assuming a carbon price.
- **Capital Costs:** Where available, baseline resource capital costs were developed utilizing a blend of All-Source RFP results and National Renewable Energy Laboratory ("NREL") Annual Technology Baseline ("ATB") curves, with adjustments made for inflation and supply chain constraints. These inputs ensure new technologies are evaluated on realistic, market-informed economics.
- **Resource Cost and Performance:** All-Source RFP data was supplemented with a comprehensive technology assessment by 1898 & Co., which was used to validate the capital, fixed and variable O&M, and operational performance assumptions of all resource types under consideration. Where data was not available from the All-Source RFP, the technology assessment was utilized. For example, CEI South utilized the technology assessment for several gas options, advanced nuclear, etc.
- **Demand-Side Resources:** A Market Potential Study ("MPS") developed with GDS Associates informed energy efficiency and demand response potential. These demand-side inputs were modeled on a consistent and comparable basis with supply-side resources to capture full system cost and performance tradeoffs.
- **Transmission Planning:** CEI South conducted a focused transmission study in parallel with generation strategy development to evaluate deliverability, upgrade needs, and local system constraints. The study identified areas where interconnection limitations or thermal constraints could impact various portfolios and ensured that Reference Case portfolios reflect realistic transmission system capabilities.

Portfolio modeling under the Reference Case was conducted using EnCompass, which performed a capacity expansion analysis to identify the least-cost resource mix, followed by chronological dispatch modeling to assess operational feasibility and system performance. The Reference Case was also used as the central comparison point in risk and scorecard evaluation to test how alternative portfolios perform under expected conditions.

2.7. Alternative Scenarios

While the Reference Case provides an outlook on likely future conditions, CEI South recognizes that long-term resource planning must account for the inherent uncertainty in regulatory policy, technology costs, economic development potential, and customer

demand. To stress-test portfolios across a broad range of possible futures, the IRP included four Alternative Scenarios that were each structured to represent distinct, plausible deviations from the Reference Case.

These alternative scenarios are not forecasts or policy goals; instead, they serve as analytical “bookends” that help reveal how portfolios perform when challenged by differing policy mandates, commodity prices, demand growth rates, or environmental regulation.

Each scenario alters multiple input drivers simultaneously, such as fuel prices, load trajectories, capital costs, and environmental policy, to reflect a coherent and internally consistent worldview. Together, they provide insight into how different futures affect system needs, cost exposure, and implementation risk.

Alternate Reference Case
This scenario retains the same policy and regulatory assumptions as the Reference Case but introduces high load growth and is representative of several potential economic development opportunities. It explores the impact of potential large-scale developments such as emerging technologies like AI data centers, metal smelting plants, etc. that could rapidly accelerate electricity demand. This high-demand future was set up to evaluate potential portfolios to maintain affordability, operability, and resource adequacy under increased load conditions on an accelerated timeline. It also tests the responsiveness of transmission and interconnection pathways under fast buildout.

High Regulatory
The High Regulatory scenario reflects a future shaped by progressive federal or state decarbonization mandates. This includes a consensus carbon price utilizing Hitachi, EVA, and S&P forecasts as source data, faster fossil retirements, and tighter compliance obligations under the Clean Air Act and other environmental statutes. Clean energy deployment is further accelerated through economic incentives including the renewable tax credits under the IRA, supporting rapid expansion of renewables and storage. Portfolios in this future must accommodate a faster transition away from legacy assets while preserving reliability and cost control under accelerated timelines and regulatory pressure.

Alternate High Regulatory
This variation on the high regulatory scenario was created due to stakeholder input; it assumes continued regulation under the Clean Air Act, without direct carbon pricing, but introduces elevated load growth tied to electric vehicle adoption, enhanced electrification incentives, and economic expansion. While regulatory pressure is still present, the primary driver of change in this scenario is demand growth, coupled with slightly less regulation than the high regulatory scenario. Supply chain constraints and development

bottlenecks amplify the complexity of meeting new load, increasing capital costs and siting challenges. Energy efficiency program costs are assumed to continue at baseline levels; as there is greater opportunity for EE under increased load conditions. This scenario tests portfolios for their ability to scale under load and capital pressure while maintaining regulatory compliance.

Low Regulatory

The Low Regulatory scenario represents a future with further repeal of progressive environmental rules. CAA 111(b) and (d) are repealed, and no new decarbonization mandates are introduced. IRA provisions are cancelled, and resource decisions are driven primarily by market forces and asset-level economics. This Low Regulatory scenario emphasizes affordability and system stability, favoring legacy asset utilization and measured adoption of new technologies. This scenario helps identify portfolios that remain viable in policy-light conditions with limited external drivers for transition.

Scenarios Summary

The following graphic provides a side-by-side comparison of the five planning scenarios used in this IRP. Each scenario reflects a distinct set of assumptions related to environmental regulation, federal policy, demand growth, fuel pricing, capital costs, and technology adoption. This visual summary highlights the key drivers that differentiate these futures and illustrates how CEI South tested the robustness of candidate portfolios across a wide spectrum of uncertainties.

Figure 2-2 – Scenario Summary

Key Drivers:	Policy Factors			Load	Commodity Prices		Capital Costs	
Scenario	Environmental Policy	Economic Policy	CO_2 Regulation	Load	Natural Gas Price	Coal Price	Generation	EE Costs
Reference Case	ACE Proxy	Modified IRA	No additional CO_2 regulation	Base	Base	Base	Base	Base
Alternate Reference Case	ACE Proxy	Modified IRA	No additional CO_2 regulation	Much Higher	Base	Base	Base	Base
High Regulatory	Clean Air Act 111 (b & d) and expansion to existing gas resources	IRA	Addition of CO_2 Tax	Lower	Higher	Higher	Lower	Higher
Alternate High Regulatory	Clean Air Act 111 (b & d) and expansion to existing gas resources; Electrification and EV policy	IRA	No additional CO_2 regulation	Higher	Higher	Higher	Higher	Base
Low Regulatory	No Clean Air Act 111 (b & d)	No IRA	No additional CO_2 regulation	Higher	Lower	Lower	Higher	Lower

Together, these five scenarios form the analytical backbone of CEI South's deterministic portfolio development and evaluation processes. Four of these worldviews, core scenarios (Reference Case, High Regulatory, Alternate High Regulatory, and Low Regulatory), served as the primary analytical foundation for this IRP. By modeling a range of regulatory, economic, and operational conditions, the IRP attempts to capture the spectrum of challenges that may emerge over the planning horizon. Each scenario was constructed to test how resource decisions could change relative to key drivers, as well as providing a view into how each portfolio would perform if applied to a different future. It also helps ensure that no single set of assumptions determines the outcome.

The fifth scenario, the Alternate Reference Case was developed as an alternate parallel analysis, providing additional perspective on the unique impact of a large load addition within CEI South's service territory. Since the load forecast and overall system need significantly differ from those found in the other scenarios, this worldview was modeled separately. This is discussed further in Section 6, The Alternate Preferred Portfolio.

This scenario-based framework enhances transparency and decision-making confidence. It enables CEI South to identify portfolios that are not only cost-effective under expected conditions but also resilient in the face of disruptive change. The insights from scenario modeling directly inform the risk evaluation and scorecard comparison process that follows, ultimately helping shape the selection of a Preferred Portfolio that balances affordability, reliability, resilience, stability, and environmental sustainability, and implementation feasibility across all plausible futures.

2.8. Planning Priorities and Guiding Principles

To bring clarity to how CEI South evaluates potential resource portfolios, this IRP is organized around the five pillars, into three overarching evaluation layers. These layers reflect the practical structure of utility decision-making; first, establishing whether a portfolio is technically viable, second, determining which feasible portfolios best align with customer priorities, stakeholder values, and long-term policy uncertainty, and third, ensuring all risks such as market, policy, and execution risks are accounted for.

Technical Requirements

Reliability – Reliability is foundational to electric system planning and refers to the ability of a portfolio to maintain sufficient generation capacity to meet peak demand. CEI South assessed resource adequacy using capacity expansion modeling that enforced MISO Planning Reserve Margin Requirements ("PRMR"), along with seasonal and annual load shape variation. Resource accreditation was modeled according to MISO's seasonal capacity valuation methodologies and included the transition to direct-loss-of-load

accreditation methodology beginning in 2028. Portfolios that failed to maintain reserve adequacy were not included for consideration.

Stability – Grid operability refers to the capacity of a portfolio to maintain real-time and near-term system stability, including frequency regulation, voltage support, inertial response, and ramping adequacy. To evaluate operability, CEI South leveraged production cost modeling that simulated hourly dispatch and reserve commitment over the full planning horizon. These simulations tested portfolios for ability to manage renewable intermittency, net load variability, and contingency events while complying with reliability standards. Dispatchable thermal resources, fast-ramping assets, DR, and renewable generation were all critical to ensuring operability in modeled futures.

Resilience – Resilience reflects the ability of the electric system to prepare for, absorb, and recover from disruptive events, such as extreme weather, prolonged fuel supply limitations, correlated renewable shortfalls, and simultaneous generation derates. CEI South evaluated resilience through scenario-based and probabilistic-based modeling. Portfolio resilience was quantified through the total installed capacity of resources capable of fast start and spinning reserve benefits. Beyond the metrics, the inclusion of resources that offer black start capability were considered. Through price fluctuations, capacity factor limitations, and other variations in market conditions and assumptions, the portfolios were stress-tested and the system-wide response capability was evaluated.

Strategic Differentiators

Affordability – Affordability is evaluated using the Net Present Value of Revenue Requirements (“NPVRR”), which captures all generation-related costs, including but not limited to the following: capital, O&M, fuel, and market purchases – discounted over the 20-year planning horizon. This metric enables consistent comparison of portfolios with differing investment profiles and cost timing. CEI South examined NPVRR three ways: the mean value, and the 95^{th}/5^{th} percentile across 200 stochastic iterations. The 5^{th} and 95^{th} percentile represent possible boundary conditions for the 20-year costs, helping to measure cost risk. In addition to system-level costs, CEI South considered Incremental Electric Energy Burden, defined as total electric costs as a percentage of household income, to evaluate near to mid-term affordability of portfolio decisions on customer bills.

Environmental Sustainability – Environmental sustainability was assessed by analyzing portfolio emissions relative to expected environmental regulations and policy drivers. Modeling included assumptions around IRA incentives, potential Clean Air Act regulatory requirements, and carbon prices in the high regulatory scenario. Portfolios were also reviewed for alignment with stakeholder values around decarbonization, public health, and long-term climate risk mitigation.

Risk Management

MISO Market – Participation in the MISO market provides valuable flexibility, but increased reliance on market purchases introduces cost and reliability risks, especially as regional conditions evolve. Thermal retirements and rising renewable penetration may reduce capacity market liquidity and heighten price volatility during system stress.

To help illustrate tradeoffs, CEI South modeled energy market exposure across all scenarios, applying purchase limits mirroring system constraints and requiring portfolios to have a minimum level of self-sufficiency. This approach helps ensure resource adequacy even when market conditions are unfavorable.

Federal Policy – The Inflation Reduction Act included significant tax credits that enhance the economics of renewables, storage, and low-carbon technologies. While these incentives improve portfolio affordability and emissions performance, they also introduce planning risk due to evolving regulatory guidance, compliance complexity, and potential policy reversals. Scenarios were constructed with and without IRA tax incentives to evaluate boundary conditions, the One Big Beautiful Bill Act repeal and reinstatement of IRA incentives.

Execution and Supply Chain – Implementing large-scale resource transitions requires coordination across permitting, procurement, interconnection, and construction, each vulnerable to delays and cost escalation. National supply chain constraints, equipment lead times, and labor shortages present material risk to project execution.

CEI South incorporated these risks into modeling through cost sensitivities and contingencies, while also qualitatively assessing the scale and complexity of each portfolio. Portfolios with phased buildouts, technology diversity, and distributed development timelines were favored to reduce execution risk and support achievable, cost-effective implementation.

The final definitions of the objectives and metrics that were provided in the fourth Stakeholder meeting can be reviewed in the following table.

Figure 2-3 – Objectives, Measures, & Metrics

Objective	Measure	Metrics
Affordability: Consider portfolios' impact on the retail electric utility service providers' ability to provide affordable power across residential, commercial, and industrial customer classes	20-year NPVRR across 200 dispatch iterations under varying market conditions	millions$
	95th percentile of NPVRR across 200 dispatch	millions$

Objective	Measure	Metrics
	iterations under varying market conditions	
	5th percentile of NPVRR across 200 dispatch iterations under varying market conditions	millions$
	Incremental Electric energy burden (2030 – 2035)	% HH Income
Environmental Sustainability: Consider the impact of environmental regulations on the cost of providing electric utility service and demand from consumers for environmentally sustainable sources of electric generation	CO_2 Intensity	Tons/ CO_2/kwh
	CO_2 Equivalent Emissions	Tons CO_2e
	SO_x and NO_x Emissions	Tons
Reliability: Consider portfolios' ability of the electric system to supply the aggregate electrical demand and energy requirements of end use customers at all times and withstand sudden disturbances **Resiliency:** Consider portfolios' ability to adapt to changing conditions and withstand and rapidly recover from disruptions **Stability:** Consider portfolios' ability to maintain a state of equilibrium during normal and abnormal conditions or disturbances and deliver a stable source of electricity, in which frequency and voltage are maintained within defined parameters	Unserved energy across 200 dispatch iterations under varying market conditions	MWh
	Spinning Reserve	Portfolio MW's that offer spinning reserve
	Fast Start Capability	Portfolio MW's that offer fast start
	Transmission reliability analysis	Dynamic VAR support ("MVAR") Short Circuit Ratio ("SCR")
Risk/Other:	Energy market purchase and sales	% (average, near/long-term)
	Capacity sales and purchases	$

2.9. Comprehensive Portfolio Development & Testing

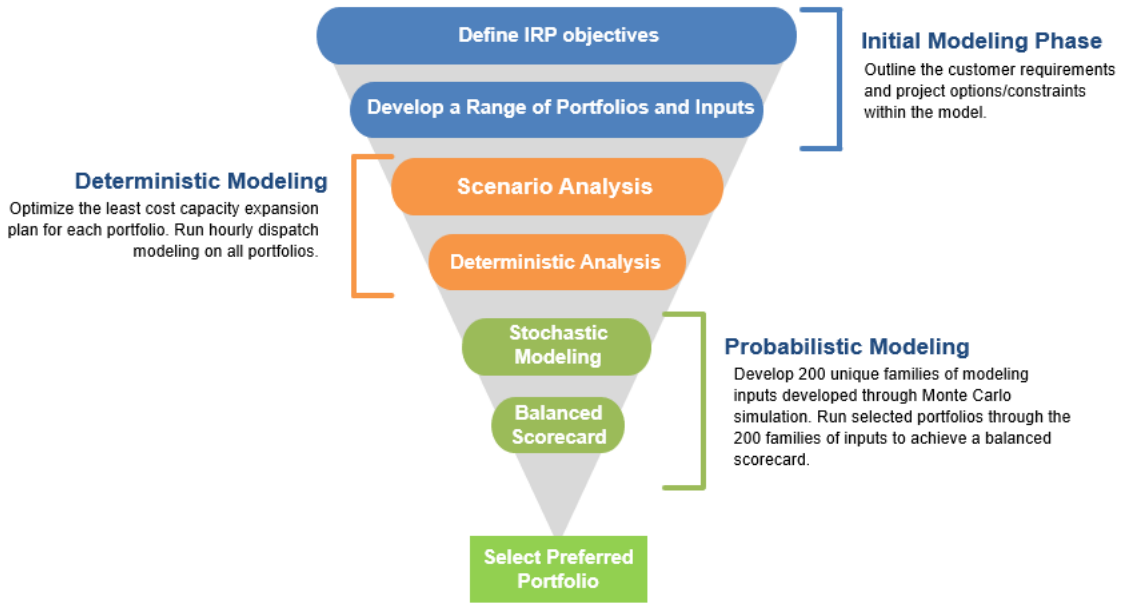
Following the completion of scenario design and modeling setup, CEI South initiated an iterative portfolio development process to explore and evaluate long-term resource pathways. Three major decisions were evaluated within this IRP: replacement of F.B. Culley 2 interconnection, the next three-year DSM Plan, and evaluation of F.B. Culley 3,

CEI South's last remaining coal unit that it operates. For portfolio development, economic decisions for DSM programs were locked in prior to building out the final 12 portfolios. Then, the process began with initial runs of the primary scenarios designed to identify common themes across load, policy, and cost conditions. Resources that consistently emerged across scenarios, such as early storage or demand-side measures, were considered for inclusion in a "going-in" resource position to anchor subsequent modeling. Then CEI South focused on capacity need and built around various resource options to replace or maintain F.B. Culley 3.

Building from this foundation, CEI South constructed a broad set of candidate portfolios that reflect diverse planning priorities and technology pathways. These portfolios were then evaluated against CEI South's predefined criteria, including but not limited to technical performance, customer affordability, emissions outcomes, and implementation feasibility.

Figure 2-4 below illustrates the structured, multi-step approach used to refine, test, and compare resource strategies before selecting a final Preferred Portfolio. Note that with the inclusion of the Alternate Reference Case, this multi-step approach was performed once with the core scenarios and then again with the Alternate Reference Case inputs.

Figure 2-4 – Portfolio Development Process



Modeled Portfolios

Each portfolio represents a distinct pathway for meeting future energy needs, varying by generation mix, retirement timing, renewable adoption, and storage deployment. These resource portfolios test specific planning themes, and while some emphasize emerging resource types, others prioritize system flexibility. Several explore the role of legacy resources under evolving market and regulatory conditions. By modeling a wide range of options, CEI South was able to evaluate tradeoffs and performance across multiple dimensions, including reliability, cost, emissions, and implementation risk, under the four core planning scenarios. Twelve portfolios were evaluated in the final risk analysis. These portfolios and the selection process will be discussed further in Section 4, Portfolio Development and Evaluation.

The modeling framework included EnCompass and PSSE software packages to support both long-term system development and near-term operational analysis. These tools allowed CEI South to capture cost, reliability, and policy tradeoffs with appropriate technical rigor.

Capacity Expansion Modeling

For each scenario, capacity expansion modeling was used to identify optimal long-term resource plans that met planning reserve margins, and reliability criteria, while minimizing system cost. Fixed generation strategies, such as early coal retirement or prescribed storage additions, were used in certain runs to explore how portfolio configurations responded under controlled planning assumptions. Additionally, this strategy was used to create portfolios with a wide range of potential technologies to maintain needed capacity.

Production Cost Modeling

Once expansion plans were established, system dispatch and production costs were simulated on an hourly basis. This allowed CEI South to assess operational dynamics, including renewable integration, unit starts, expected unserved energy, and emissions output. These production cost insights ensured that modeled portfolios were not only cost-effective in theory but also viable under real-world system conditions.

Probabilistic Analysis

Recognizing the uncertainty inherent in long-term planning, CEI South performed targeted sensitivity analyses to test portfolio robustness. Key variables including fuel prices, load growth, carbon costs, energy sales, and capital expenses were varied within reasonable bounds. This helped identify portfolios that consistently performed well across multiple risk dimensions, even under adverse conditions.

Sensitivity Analysis

Sensitivity analysis is conducted to evaluate certain risks. It includes changing only one

variable at a time to understand the impact of a single risk factor. In some cases, the sensitivity is used as a screening tool for ideas to see if the risk is worth further exploration within more comprehensive modeling. In other cases, it was used to provide more insight into the impact of one cost driver or explore potential differences in resource build out. Sensitivity analysis is particularly helpful in explaining isolated impacts that stakeholders or the company is interested in.

Together, these modeling efforts produced a well-rounded view of how candidate portfolios would perform across regulatory, economic, and operational contexts.

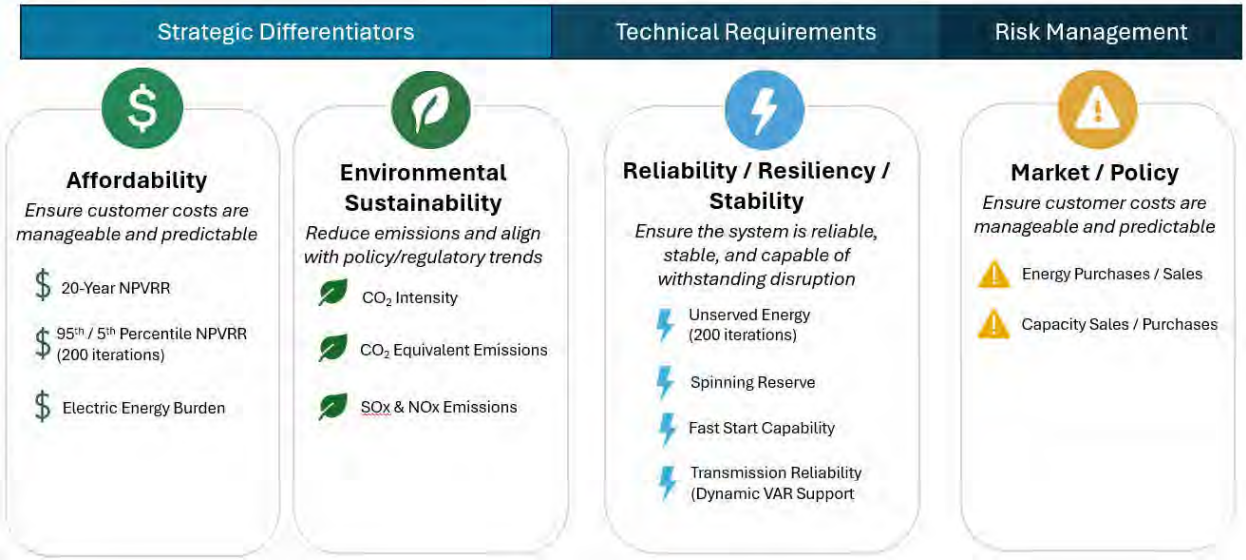
2.10. Portfolio Scorecard Evaluation

Once candidate portfolios were developed and tested, CEI South used a scorecard-based framework to compare performance across the three evaluation layers outlined above. This approach translated complex modeling outputs into a structured decision-making tool, allowing CEI South to balance technical feasibility with strategic value.

Evaluation Framework Summary

Figure 2-5 summarizes how CEI South's evaluation criteria are organized into the three assessment layers, Technical Requirements, Strategic Differentiators, and Risk Management. The image also illustrates the specific pillars, objectives, and performance metrics considered within each layer. This structure enables transparent, side-by-side comparison of portfolios across operational, economic, environmental and risk dimensions.

Figure 2-5 – Evaluation Objectives, Measures & Metrics



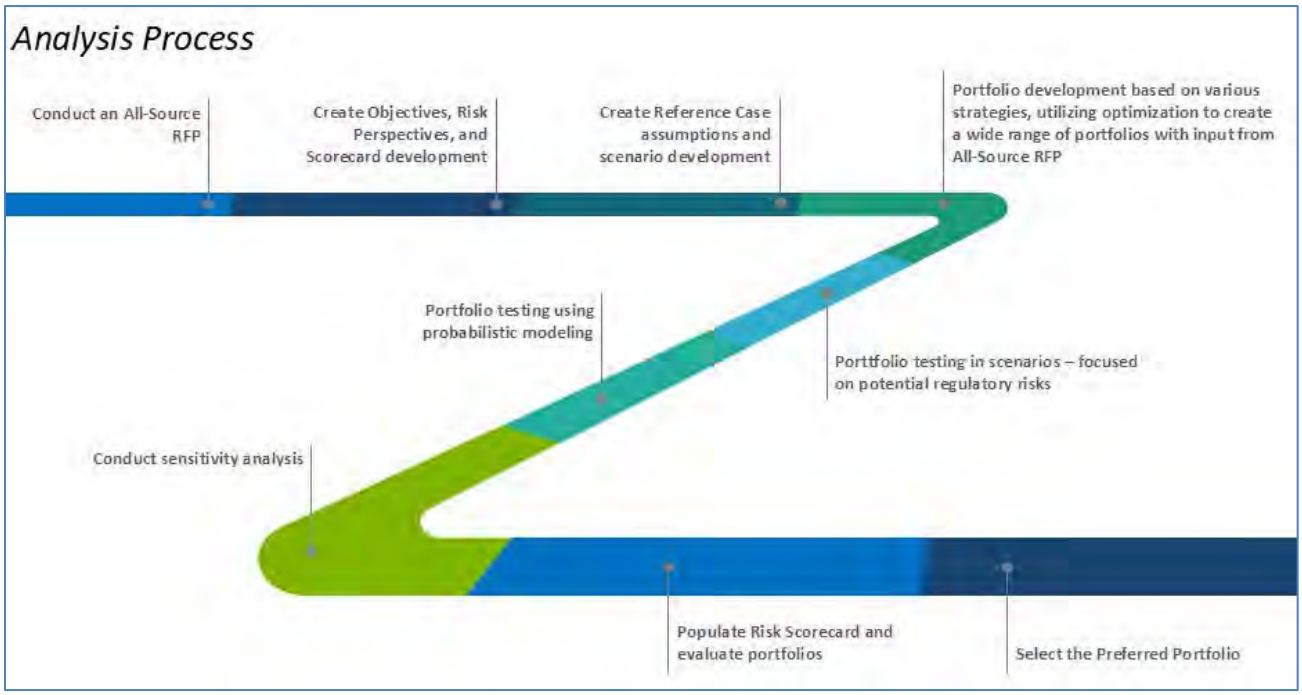
Together, this method ensures that CEI South's Preferred Portfolio is not only technically sound and cost-effective, but also robust under a range of future uncertainties. By integrating operational standards, long-term strategic objectives, and explicit risk considerations, the framework supports balanced decision-making and reflects CEI South's commitment to reliable, affordable, resilient, stable, and environmentally sustainable service for its customers. This structured approach also provides transparency and an opportunity for stakeholder engagement, reinforcing confidence in the IRP process and its outcomes.

2.11. Analytical Process & Tools

2.11.1. Analytical Roadmap

As shown in Figure 2-6, CEI South initiated the IRP process with the 2024 All-Source RFP (*Technical Appendix Attachment 2.1*), which provided current market data on resource availability and pricing. Following the 2024 All Source RFP, CenterPoint developed key evaluation metrics, perspectives, and scenario worldviews based on stakeholder input and existing knowledge. These scenarios, combined with additional planning considerations, were used to create potential future portfolios. Each portfolio was then evaluated through probabilistic modeling and various sensitivity analyses to quantify risk and performance under varied market conditions. Finally, the results were evaluated, and a Preferred Portfolio was selected.

Figure 2-6 – Analytical Roadmap



2.11.2. Modeling Tools

The primary modeling software used to assist in portfolio development, probabilistic modeling, and sensitivity analysis was the EnCompass capacity expansion and production cost simulation software package, licensed from Yes Energy. The National Database provided by Horizons Energy was used to represent the broader power grid beyond CEI South's service territory.

In parallel with generation system planning, a comprehensive transmission assessment was performed using the PSS/E software, licensed from Siemens. This analysis incorporated the MISO Transmission Expansion Planning ("MTEP") 2024 dataset to reflect the current state of the regional transmission network, supplemented with system-specific insights provided by CEI South.

2.11.3. Process Enhancements

Several enhancements were made to the IRP process in alignment with feedback from the previous IRP cycle and stakeholder requests. These updates included refinements to objectives and metrics, expanded sensitivity analysis, improvements to probabilistic

modeling, and other process modifications intended to increase transparency and stakeholder engagement throughout the IRP development.

2.11.3.1. Enhancements to Objectives and Metrics

Additional scoring measures were introduced across the pillars to provide a more comprehensive assessment of the impacts evaluated in this study. Under the affordability metric, the 5th percentile of the NPVRR was added to the final scorecard, in addition to the traditional 95th percentile, to better represent the potential range of customer cost outcomes under varying future conditions. In response to stakeholder requests, electric energy burden was also incorporated as a new affordability metric. Accordingly, 5- and 10-year incremental electric energy burdens were calculated by dividing the bill impact in those years by the median household income in Vanderburgh County. This metric is intended to illustrate the potential near to mid-term impacts to customers associated with portfolio decisions made in this IRP cycle.

To strengthen the evaluation of environmental sustainability, new scoring measures were added to capture criteria air pollutants not previously reported in the scoring process. Specifically, cumulative tons of sulfur oxides ("So_x") and nitrogen oxides ("No_x") emitted were added to the environmental metrics. While previously captured in the broader CO_2 equivalent emissions intensity metric, this explicit inclusion provides greater transparency into portfolio environmental performance.

The transmission reliability analysis was conducted to assess system stability measuring the available dynamic reactive power ("VAR") support and short circuit ratio ("SCR"). Both metrics were evaluated under single element outage (N-1) conditions. The dynamic VAR support metric quantifies the maximum available reactive power on the system during an outage event by summing the total system VAR capability and accounting for each generator's reactive power contribution. Scenarios with lower dynamic VAR support may indicate potential voltage stability concerns. The SCR represents the ratio of the apparent power available at a given system bus following a fault to a benchmark apparent power value of 100 MW. Scenarios exhibiting lower SCR values are indicative of potential stability limitations. Together, these metrics help identify locations or scenarios where the system may require additional reactive support or reinforcement to maintain reliable operation.

Finally, in the risk category, capacity sales and purchases were added to the scorecard to better capture exposure associated with interactions in the market. This metric is intended to quantify the potential risks tied to capacity sales, particularly given their influence on the overall affordability results and customer cost outcomes. Moreover, highlighting reliance on

capacity purchases in this way clearly demonstrates the risks related to market capacity availability and price volatility.

2.11.3.2. Enhancements to Probabilistic Modeling

One key enhancement to the probabilistic modeling framework involved the addition of energy sales variability within the stochastic analysis. To better reflect a range of potential market conditions, the model varied the limits of allowable energy sales across the 200 probabilistic iterations. These limits were implemented at the current transfer capability of 660 MW as well as reduced limits of 330 MW and 165 MW, with each limit applied to one-third of the total draws. This improvement provides a more realistic representation of operational flexibility and market exposure, while also preventing portfolio overreliance on market energy sales revenues to offset costs.

Another improvement expanded the probabilistic modeling of capital costs beyond renewables and storage to include all resources in the model. Each resource type was assigned high, base, and low capital cost forecasts to reflect a realistic range of potential outcomes. This addition allows the model to better capture uncertainty in future costs and improves the understanding of how capital cost changes influence overall portfolio performance.

2.11.3.3. Stakeholder Scenario Input

Throughout the IRP process, stakeholders were continually offered the opportunity to provide feedback and input for incorporation into the analysis. For example, during the initial stakeholder meeting, draft scenarios were presented, prompting stakeholders to request an additional scenario with substantially different key drivers. In response, CEI South developed an Alternate High Regulatory worldview, in which environmental regulations become more stringent, while load continues to grow a rapid pace due to electrification of heating equipment and vehicles, resulting in upward pressure on capital costs. Stakeholders also proposed the development of an Alternate Low Regulatory scenario—mirroring the original Low Regulatory scenario but incorporating lower projected load growth. This latter case was included as a sensitivity analysis rather than a new scenario.

2.11.3.4. Alternate Reference Case

This IRP coincides with a period of unprecedented uncertainty in the industry, particularly related to the rapid emergence of large loads seeking interconnection to the power grid. Following stakeholder interest surrounding the impacts of potential large load additions in CEI South territory and continued interest from multiple industries to locate in CEI South's territory, CEI South introduced an Alternate Reference Case. This analysis utilized IRP capacity expansion modeling to develop multiple portfolios for further evaluation using

probabilistic modeling and selection of an Alternate Preferred Portfolio. More information on the Alternate Reference case can be found in Section 6, The Alternate Preferred Portfolio.

2.11.3.5. Expanded Sensitivity Analysis

To provide a more comprehensive understanding of portfolio performance under varying conditions, CEI South expanded the scope of sensitivity analyses performed in this IRP. These sensitivities examined the effects of several key factors, including the distributed solar incentive, large load additions, A.B. Brown 5 and 6 conversion costs, inclusion of F.B. Culley 2 storage, demand response term, and the Alternate Low Regulatory case. Together, these analyses provided greater insight into how changes in resource costs, load levels, distributed generation, and market conditions could influence portfolio development and overall system reliability.



Forecasts and Key Modeling Assumptions

Chapter 3

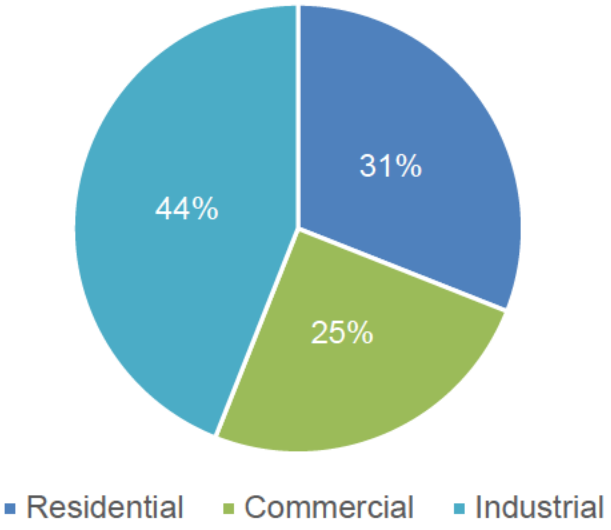
3.1. Load Forecast

3.1.1. Methodology

CUSTOMER TYPES

CEI South serves more than 150,000 electric customers in Southwestern Indiana; Evansville is the largest city within the service area. The service area includes a large industrial base with industrial customers accounting for approximately 44% of energy sales in 2024. The residential class accounts for 31% of sales with approximately 133,000 customers and the commercial class is 25% of sales; there are approximately 19,000 nonresidential customers. System 2024 energy requirements were 5,032 GWh with non-weather normalized system peak reaching 1,065 MW. Figure 3-1 shows 2024 class-level sales distribution.

Figure 3-1 – 2024 CEI South Annual Sales Breakdown



3.1.2. Forecast Drivers and Data Sources

The main drivers of the energy and demand forecast include the following: historical energy and demand data, economic and demographic information, weather data, equipment efficiencies and equipment market share data.

Itron used more than 10 years of historical energy and demand data within the energy and demand forecasts. This data is maintained by CEI South in an internal database and was provided to Itron. Energy data is aggregated by rate class for the purposes of forecasting.

There are two major rate classes for residential customers: the standard residential rate and the transitional electric heating rate (rate closed to new premises). Information for these rates is combined for the purposes of forecasting residential average use per customer ("AUPC"). Similarly, small to large commercial (general service) rates are combined to produce the commercial forecast and large customer rates are combined to produce the industrial forecast. The demand forecast utilizes total system demand.

Economics and demographics are drivers of electricity consumption. Historically, there has been a positive relationship between economic performance and electricity consumption. As the economy improves, electricity consumption goes up and vice versa. Economic and demographic information was provided by S&P Global (formerly IHS Markit), which contains both historical results and projected data throughout the IRP forecast period. Examples of economic variables used include, but are not limited to, population, income, output and employment.

Weather is also a driver of electric consumption. CEI South's peak demand is traditionally in summer when temperatures are hottest. Air conditioning drives summer usage. Itron used a trended weather assumption for the normal weather in the sales and demand forecast to capture recent weather activity. The trended weather picks up the 0.06 degree annual increase in temperature the Evansville area has experienced since 1988.

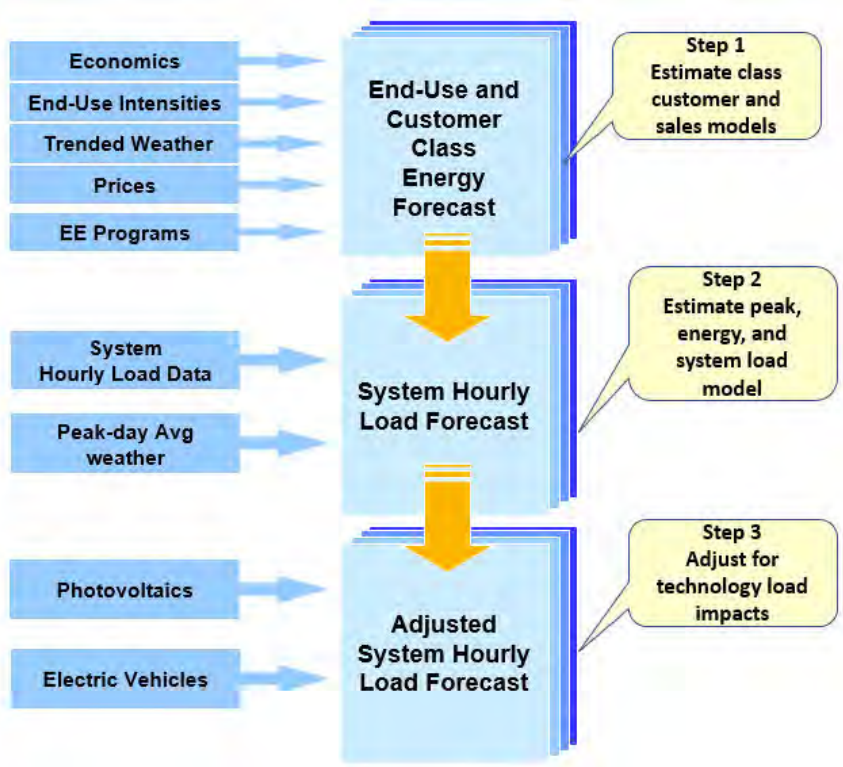
Itron provides regional Energy Information Administration ("EIA") historic and projected data for equipment efficiencies and market shares. This data captures projected changes in equipment efficiencies based on known codes and standards and market share projections over the forecast period, including but not limited to the following: electric furnaces, heat pumps, geothermal, central air conditioning, room air conditioning, electric water heaters, refrigeration, dish washers, dryers, etc. Residential market share data was adjusted to CEI South's service territory based on the appliance saturation survey data.

3.1.3. Model Framework

The long-term energy and demand forecasts are based on a build-up approach. End-use sales derived from the customer class sales models (residential, commercial, industrial and street lighting) drive system energy and peak demand. Energy requirements are calculated by adjusting sales forecast upwards for line losses. Peak demand is forecasted through a monthly peak-demand linear regression model that relates peak demand to peak-day weather conditions and end-use energy requirements (heating, cooling and other use). System energy and peak are adjusted for residential and commercial PV adoption and EV charging impacts.

Figure 3-2 shows the general framework and model inputs.

Figure 3-2 – Class Build-up Model



In the long-term, both economic growth and structural changes drive energy and demand requirements. Structural changes include the impact of changing appliance ownership trends, end-use efficiency changes, increasing housing square footage and thermal shell efficiency improvements. Changing structural components are captured in the residential and commercial sales forecast models through a specification that combines economic drivers with end-use energy intensity trends. This type of model is known as a Statistically Adjusted End-Use ("SAE") model. The SAE model variables explicitly incorporate end-use saturation and efficiency projections, as well as changes in population, economic conditions, price and weather. Both residential and commercial sales are forecasted using an SAE specification. Industrial sales are forecasted using a two-step approach, which includes a generalized econometric model that relates industrial sales to seasonal patterns and industrial economic activity. Streetlight sales are forecasted using a simple trend and seasonal model.

3.1.4. Reference Case

ENERGY AND DEMAND FORECAST (REFERENCE CASE)

For the IRP, the long-term energy and demand forecast does not include energy savings from future DSM programs; DSM activity is considered a supply option and not a reduction to demand. Excluding DSM, energy requirements increasing 0.3% per year, summer peak demand increases of 0.5% per year and winter peak demand increases 0.3% per year growth over the next 20 years. The table below shows CEI South's energy and demand forecast; the forecast includes the impact of customer owned distributed generation, electric vehicles, trended weather (warmer summers and winters), company owned distributed generation (solar and landfill gas) and customer EE outside of energy company sponsored programs but excludes future energy company sponsored DSM program savings. For more information on CEI South long-term energy and demand forecasts, including load shapes, see *Technical Appendix Attachment 3.1 2025 CEIS Long-Term Electric Energy & Demand Forecast Report, Technical Appendix Attachment 3.2 Energy and Demand Forecast Model Inputs/Outputs (Confidential)*, and *Technical Appendix Attachment 3.3 CEIS 2024 System Hourly Load.*

Figure 3-3 – Energy and Demand Forecast

Year	Energy (MWh)		Summer Peak (MW)		Winter Peak (MW)	
2025	5,201,610		1,083		813	
2026	5,191,351	-0.2%	1,083	0.0%	810	-0.4%
2027	5,203,796	0.2%	1,088	0.5%	811	0.1%
2028	5,222,633	0.4%	1,093	0.5%	813	0.2%
2029	5,235,038	0.2%	1,098	0.5%	815	0.2%
2030	5,251,045	0.3%	1,104	0.5%	817	0.2%
2031	5,262,958	0.2%	1,108	0.4%	818	0.1%
2032	5,275,867	0.2%	1,113	0.4%	819	0.2%
2033	5,271,139	-0.1%	1,115	0.2%	818	-0.2%
2034	5,272,156	0.0%	1,118	0.3%	818	0.0%
2035	5,288,369	0.3%	1,124	0.5%	821	0.4%
2036	5,321,526	0.6%	1,133	0.8%	826	0.6%
2037	5,342,859	0.4%	1,140	0.6%	830	0.4%
2038	5,367,527	0.5%	1,148	0.7%	834	0.5%
2039	5,391,397	0.4%	1,155	0.6%	838	0.5%
2040	5,422,019	0.6%	1,163	0.7%	842	0.6%
2041	5,438,402	0.3%	1,169	0.5%	846	0.4%
2042	5,460,741	0.4%	1,177	0.7%	849	0.4%

Year	Energy (MWh)		Summer Peak (MW)		Winter Peak (MW)	
2043	5,483,087	0.4%	1,186	0.7%	852	0.4%
2044	5,512,360	0.5%	1,196	0.9%	857	0.5%
2045	5,535,614	0.4%	1,204	0.7%	860	0.4%
CAGR 25-45		0.3%		0.5%		0.3%

3.1.5. Alternate Scenarios

Itron developed three alternative scenario load forecasts as part of the IRP, one for each core scenario; they include a Low Regulatory, High Regulatory, and Alternate High Regulatory with electrification forecast. These forecasts are developed by altering the model inputs such as the EV/PV forecasts, economics, and end-use saturations and efficiencies. In addition to scenario forecasts, Itron developed four large load forecasts, three for the large load sensitivity and one for the alternate reference case. These forecasts assume the additional of a large load such as an industrial customer or data center.

Figure 3-4, Figure 3-5, and Figure 3-6 show the scenario, large load, and Alternate Reference Case forecasts.

Figure 3-4 – Alternate Scenario Forecasts

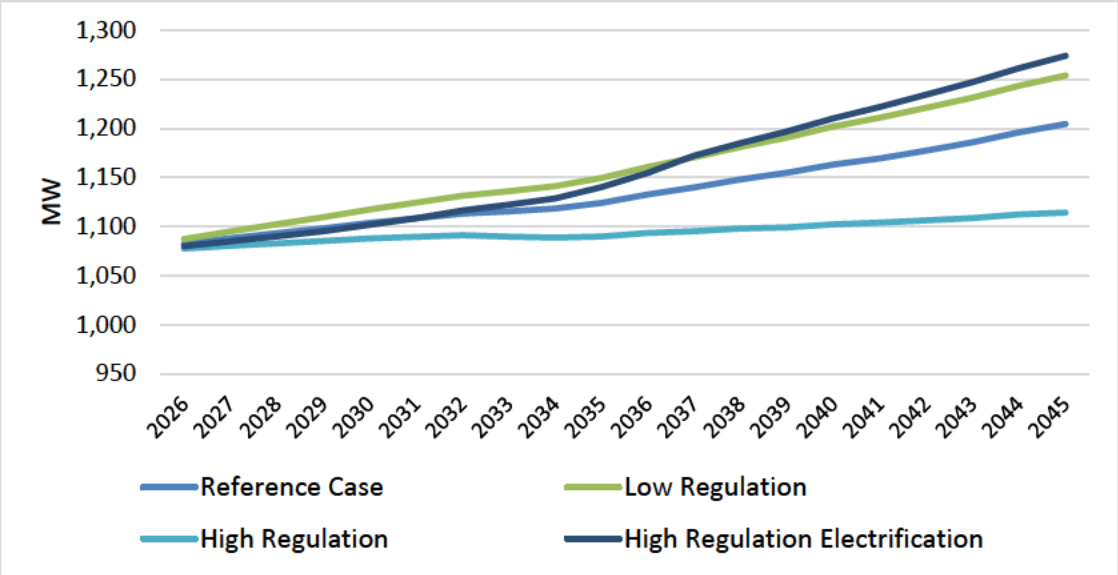


Figure 3-5 – Sensitivity Forecasts

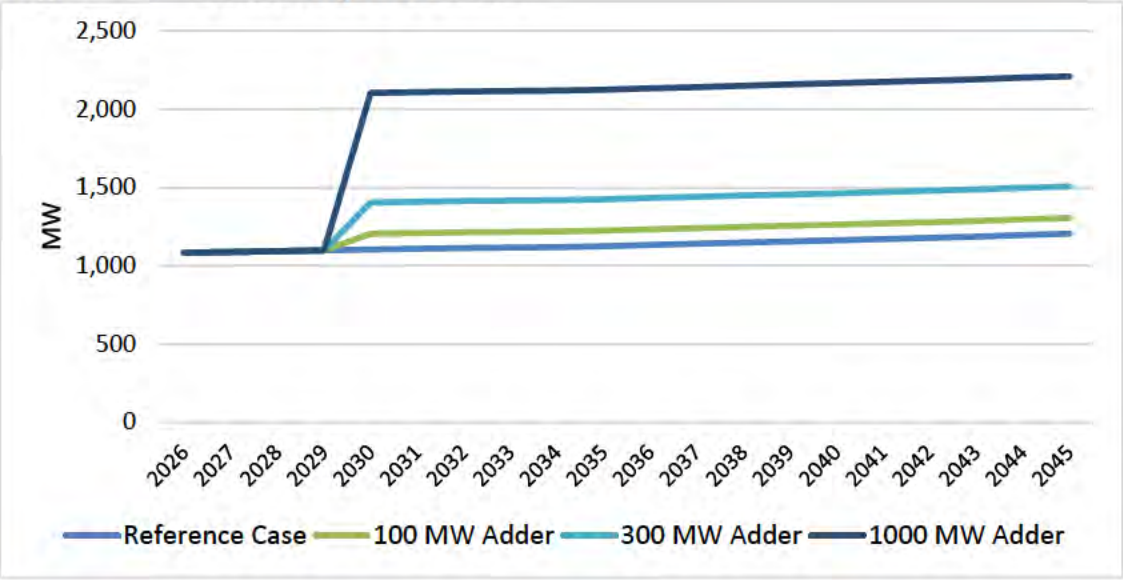
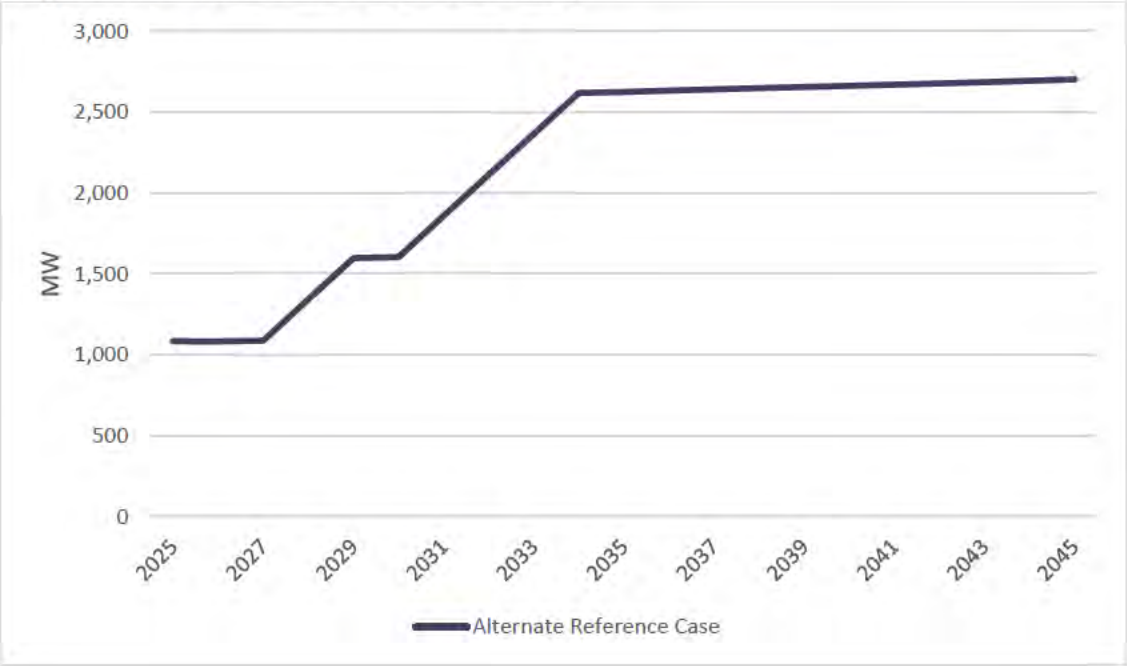


Figure 3-6 – Alternate Reference Case



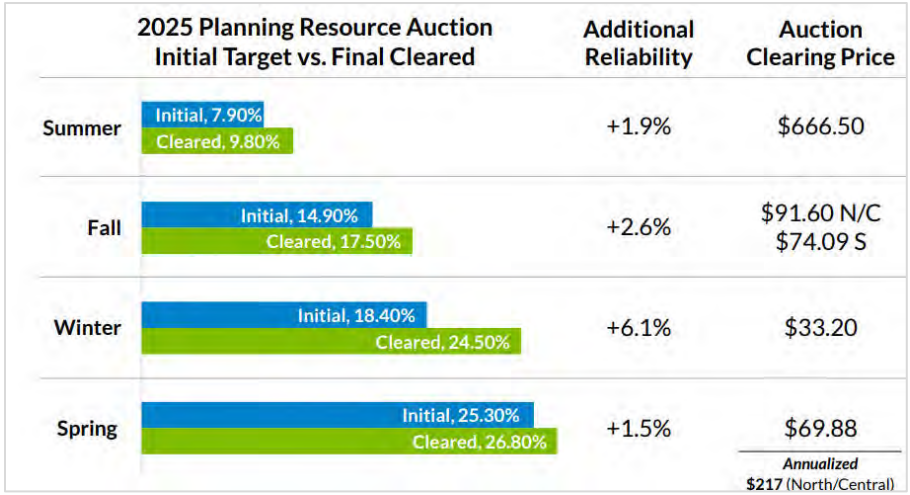
3.2. MISO

3.2.1. Planning Reserve Margin Requirement

MISO's Planning Reserve Margin ("PRM") is the percentage of additional capacity that Load Serving Entities ("LSEs"), including CEI South, must maintain above their forecasted peak demand to ensure grid reliability. The Planning Reserve Margin Requirement ("PRMR") is calculated based on the LSE's peak load forecast and the applicable PRM. The PRMR is further detailed by the Local Clearing Requirement ("LCR") which mandates how much of a LRZ PRMR must be met by generation resources physically located within that LRZ for each respective season. In recent years the number of available resources to meet load needs throughout MISO has tightened excess capacity that acts as a reliability safeguard. This trend is continuing as more baseload units are projected to retire in the coming years.

In 2024, FERC approved MISO's transition from a vertical demand curve to a reliability-based demand curve ("RBDC") for its capacity market, characterized by a sloped design, it is intended to improve MISO's capacity market by assigning value to surplus capacity based on its contribution to reliability, while also stabilizing prices, reducing volatility, and encouraging long-term investment in dependable energy resources. For LSE's the introduction of the RBDC adds complexity as each season has an initial PRM, but the final PRM can shift based on auction outcomes—requiring LSEs to estimate their potential final PRMR. The illustration in Figure 3-7[9] shows the impact of the RBDC on the 2025/2026 Planning Auction PRM.

Figure 3-7 – 25/26 RBDC Impact on the Planning Resource Auction



[9]"MISO Resource Adequacy PY 25-26: 2025 PRA Results Posting 20250529_Corrections". MISO Energy. May 29, 2025. https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250529_Corrections694160.pdf, page 5

3.2.2. Capacity Price

MISO's PRA is held annually for each of the load zones within the MISO footprint to ensure sufficient capacity resources. The PRA has yielded a wide fluctuation in capacity pricing for Zone 6 since its inaugural year of 2013, as shown in Figure 3-8 below. These large swings have made it difficult to forecast prices. Outside of the 2022-2023 anomaly, prices were relatively low for MISO's Zone 6 market participants. However, in the last three Planning Years, since the implementation of the Seasonal Construct, prices have been steadily increasing. RBDC prices are in line with MISO expectations and send more accurate price signals that properly value incremental capacity.

Figure 3-8 – MISO Capacity Prices



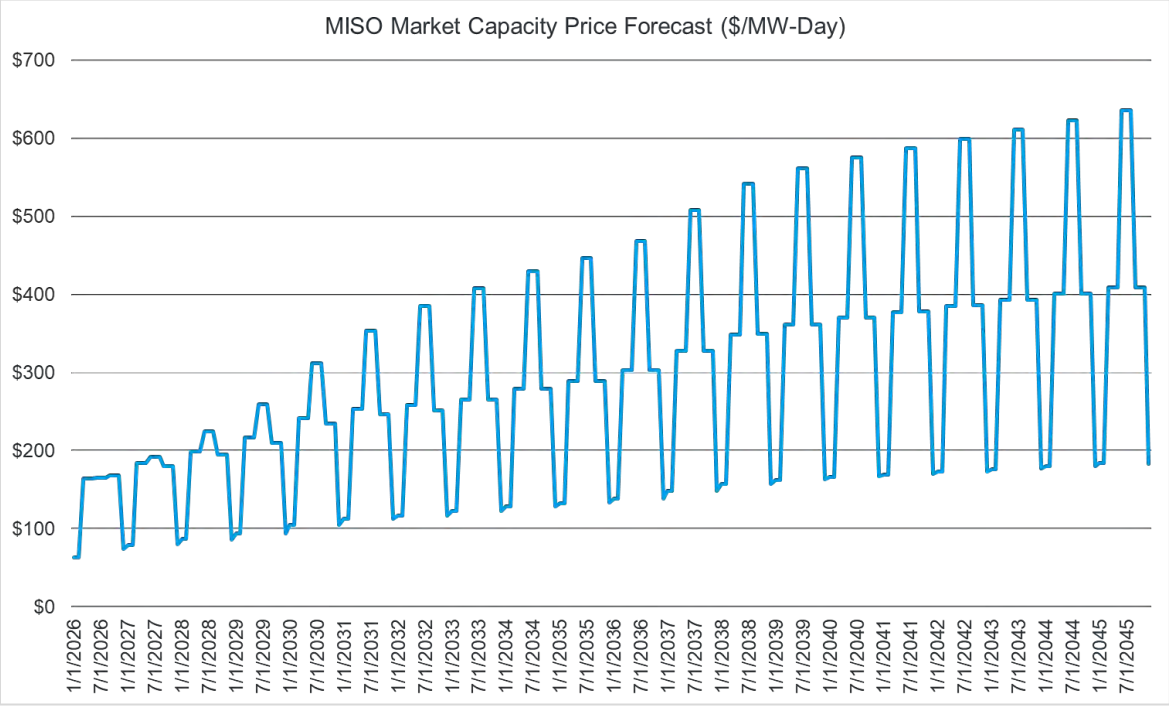
In Figure 3-9, the 2025-2026 seasonal PRA zone 6 cleared at $666.50 in the Summer, $91.60 in the Fall, $33.20 in the Winter, and $69.88 in the Spring, all in $/MW-Day.

Figure 3-9 – 2025-2026 MISO Seasonal Capacity Prices

Planning Year	Highest Clearing Price for MISO-region per MW-Day	Clearing Price for Zone 6 (Indiana & Kentucky) per MW-Day
Summer	$666.50	$666.50
Fall	$91.60	$91.60
Winter	$33.20	$33.20
Spring	$69.88	$69.88

Forward-looking capacity prices were modeled using a consensus forecast from their sources, Hitachi, S&P Global, and Wood Mackenzie. This limits reliance on a single forecast and captures views from several experts. Seasonal capacity price forecasts are given in Figure 3-10. As illustrated below, the capacity price in all seasons is increasing over time, with the summer capacity price increasing at the quickest pace.

Figure 3-10 - MISO Market Capacity Price Forecast



3.2.3. Addressing Resource Adequacy and Reliability Challenges

To address escalating reliability risks and resource adequacy challenges, MISO is executing a series of strategic reforms guided by its Reliability Imperative—a framework launched in 2020 that defines the shared responsibility among MISO, its members, and states to ensure grid reliability amid rapid change. The Reliability Imperative is structured around four pillars: Market Redefinition, Transmission Evolution, System Enhancements, and Operations of the Future, each driving targeted initiatives to manage uncertainty, integrate new technologies, and modernize planning and operations.

Key reforms have included the transition to a seasonal PRA in Fall 2022, the implementation of the RBDC effective June 3, 2024, and resource accreditation reforms scheduled for full rollout by the 2028–2029 planning year. These changes improve capacity valuation, align planning with seasonal risks, and incentivize reliable resource performance. MISO's interconnection reforms, including the Expedited Resource Addition Study ("ERAS") process launched in May 2025, aim to accelerate critical resource deployment, with the first Definitive Planning cycle beginning January 2026.

Additionally, FERC Order 881, effective December 31, 2028[10], requires utilities to implement ambient-adjusted transmission line ratings, enhancing grid efficiency and transparency, which may require improved forecasting tools and data integration to reflect dynamic transmission capabilities. FERC Order 2222 mandates the integration of Distributed Energy Resources ("DERs") into wholesale markets. MISO's compliance efforts in 2025 have involved building new workflow models and structuring communication frameworks for key roles that CEI South will incorporate into future IRPs as it becomes clearer how DER aggregation, visibility, and dispatchability affects our system. The impact of these regulatory changes is addressed in more detail below.

3.2.3.1. Direct Loss of Load ("DLOL") Resource Accreditation

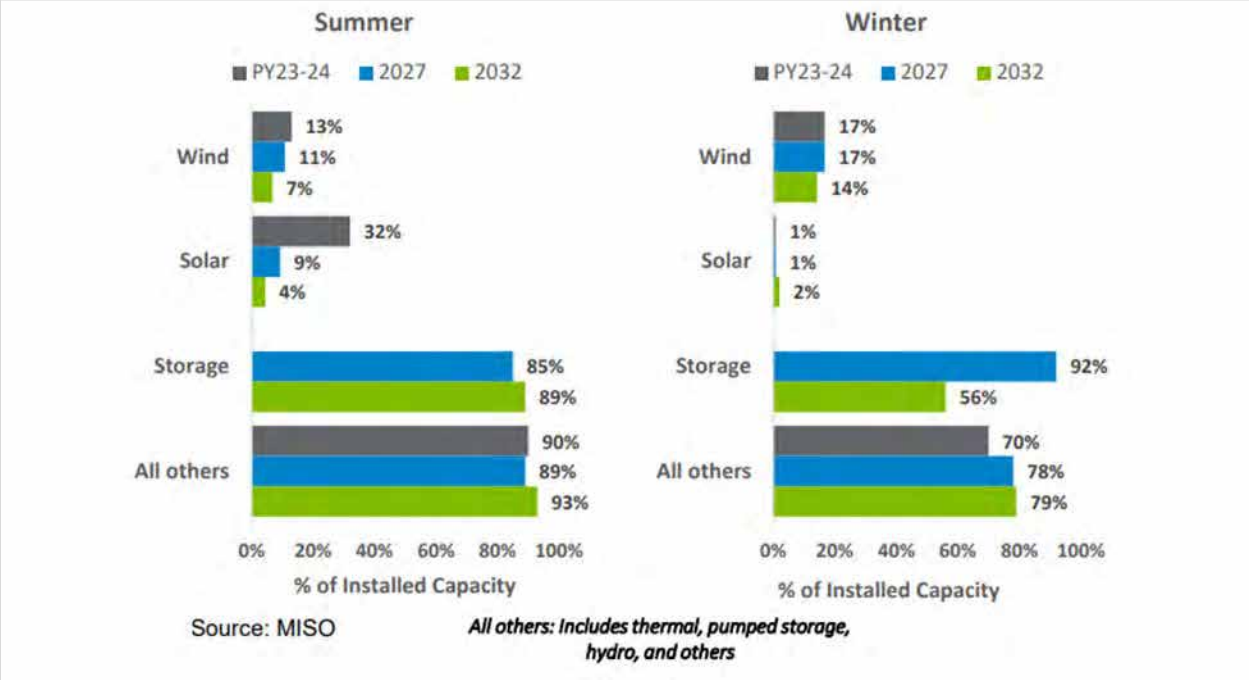
MISO is undergoing a pivotal transformation in its resource portfolio. A substantial portion of dispatchable thermal generation is approaching retirement, while being replaced by a growing share of weather-dependent, intermittent wind and solar resources. This shift combined with the increasing penetration of variable generation and the rising frequency of extreme weather events is fundamentally altering the nature of system risk and presenting new challenges to maintaining reliable grid operations, as part of MISO's broader Resource Availability and Need ("RAN") initiative (2019) and Market Redefinition, MISO proposes a two-step accreditation framework, known as the DLOL-based methodology, to address emerging reliability challenges and ensure a balanced, diverse resource mix. This approach also builds on recent reforms, including FERC's approval of Seasonal Accreditation ("SAC") and the shift to a seasonal PRA.

MISO's proposed DLOL-based resource accreditation methodology involves two steps. First, it uses a probabilistic assessment to estimate a resource's expected contribution to reliability by analyzing class-level performance during high-risk periods, based on 30 years of weather and load data through Monte Carlo simulations. Second, it applies a

[10] "Commissioner Rosner's Concurrence on Order Granting Extension of Time re MISO, Inc. under ER22-2363 | Federal Energy Regulatory Commission". FERC News. June 6, 2025. https://www.ferc.gov/news-events/news/commissioner-rosners-concurrence-order-granting-extension-time-re-miso-inc-under.

deterministic assessment that evaluates each resource's historical performance during critical reliability hours to assign accreditation within its resource class. Seasonal and resource-specific impacts under MISO's DLOL based resource accreditation methodology reflect a shift in reliability risk from summer to winter, which significantly affects solar and wind resources. Solar accreditation declines as penetration increases due to reduced effectiveness during evening risk hours, while both wind and solar receive lower proposed accreditation values compared to current methods. In contrast, thermal and storage resources maintain more stable accreditation levels, though they are still influenced by probabilistic risk modeling. The DLOL methodology began a three-year transition starting September 1, 2024, with full implementation targeted for the 2028/29 Planning Year.

Figure 3-11 – MISO DLOL Accreditation Forecast



3.2.3.2. Demand and Emergency Resources Accreditation Reforms

MISO's Demand and Emergency Resources Accreditation Reforms introduce a performance-based approach to resource accreditation, emphasizing availability during high-risk reliability periods. Utilities must now account for seasonal and hourly availability rather than static nameplate capacity and adjust planning reserve margins accordingly. With emergency DR programs being phased out starting in 2025 and full implementation of the reforms by Planning Year 2028–2029, IRPs developed during this transition must

reflect evolving accreditation values and anticipate reduced capacity credits for certain demand-side resources[11].

3.2.4. Generation Interconnection Process

Before a new generating facility can connect to the MISO-controlled transmission network, the new energy source is evaluated and approved through the MISO Generator Interconnection Process. The Generator Interconnection Process ("GI") defines the steps an interconnection customer and MISO take to move interconnection requests through the interconnection queue[12].

The three steps are: Pre-Queue, Application Review and Definitive Planning.

Pre-Queue: Provides interconnection customers with an overview of the Generator Interconnection process, including timelines and output expectations.

Application Review: MISO reviews the request, checks customer readiness, and conducts a mandatory scoping meeting.

Definitive Planning Phase ("DPP"): The final phase of MISO's generator interconnection study process where MISO conducts reliability and deliverability studies that determine whether there is available transmission capacity to accommodate the interconnection of a new, proposed generation facility or whether network upgrades are needed.

Upon completion of the third DPP, MISO and the GI requestor begin the GI Agreement ("GIA") process. After satisfying all terms of the GIA, the GI requestor will receive a fully executed GIA that enables the generator to connect to the MISO transmission system and depending on the transmission service selected, participate, and receive full accreditation in the MISO energy and capacity markets.

3.2.4.1. Interconnection Reforms

In parallel to MISO's strengthening of system reliability and resource adequacy initiatives, MISO is advancing key interconnection reforms to meet the 373-day processing timeline per MISO's Tariff. This includes implementing a queue volume cap to manage the surge

[11] "IRP Contemporary Issues Technical Conference". IN.GOV-IURC. June 6, 2024. https://www.in.gov/iurc/files/MISO-Resource-Accreditation-Reform-IRP-Contemporary-Issues-Technical-Conference-06062024.pdf

[12] Midcontinent Independent System Operator, Inc., Generator Interconnection and Retirement, available at https://www misoenergy.org/planning/resource-utilization/generator-interconnection/

in interconnection requests, limiting new proposals to 50% of each region's non-coincident peak load to reduce delays and improve study accuracy. Alongside this, financial reforms have increased milestone payments and introduced penalties for late-stage withdrawals from the queue to discourage speculative projects and streamline the process. SUGAR (Suite of Unified Grid Analyses with Renewables) is MISO's advanced automation tool developed to streamline and accelerate interconnection studies. SUGAR significantly reduces engineering time from months to minutes by automating tasks like base case creation, voltage and thermal violation detection, and contingency analysis. It has demonstrated a 99.2% match rate with legacy MISO studies and is being used to support Phase 1 of the DPP. Together, these coordinated initiatives reflect MISO's commitment to efficient resource integration and maintaining system reliability[13].

3.2.4.2. Expedited Resource Addition Study ("ERAS")

Resource adequacy is the cornerstone of MISO's FERC-approved ERAS process, which was established to accelerate the interconnection of generation resources deemed critical for near-term reliability. ERAS enables states or load-serving entities like CEI South to nominate projects that directly address resource adequacy needs such as meeting planning reserve margins or replacing retiring capacity allowing these projects to bypass the traditional queue. Designed as a temporary mechanism to mitigate emerging reliability risks until broader queue reforms are implemented by 2028. ERAS is limited in scope and duration, concluding by August 31, 2027, with a cap of 68 projects and a maximum of 15 per quarter[14].

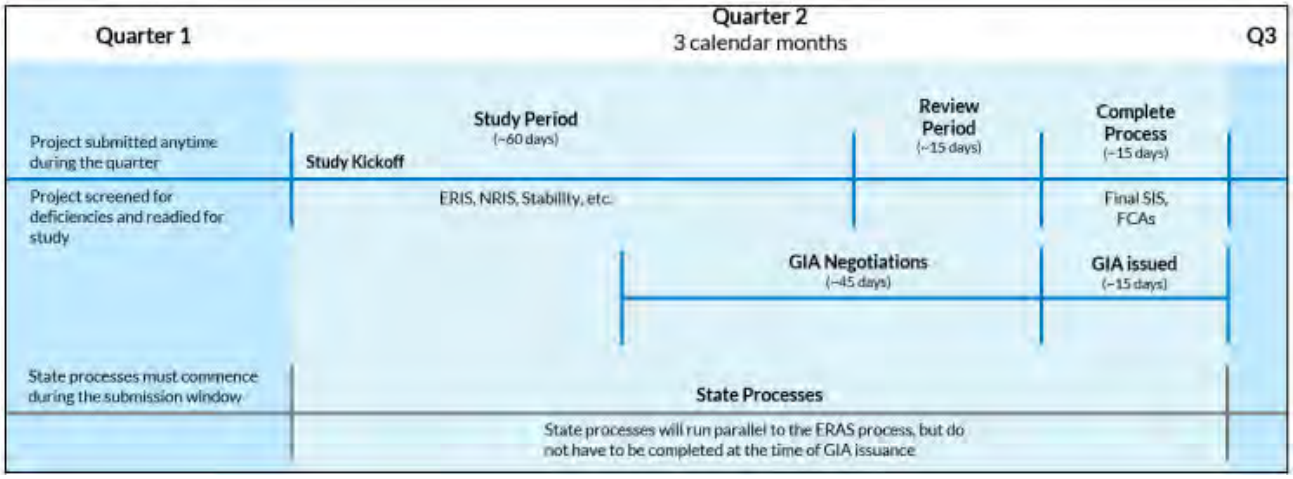
Eligible projects must resolve a specific load addition or resource adequacy deficiency, be commercially operable within 3–6 years of submission, and receive interconnection service capped at 150% of the identified need within the same Local Resource Zone. Each nomination must be verified by the Relevant Electric Retail Rate Authority ("RERRA") to confirm the necessity of the project. As of September 2025, MISO has received 47 ERAS applications totaling 27 GW of capacity. These projects represent a diverse mix of energy sources—primarily gas (74%), followed by nuclear (15%), solar and wind (each 4%), and storage (3%). The applications span multiple states, indicating a

[13]"MISO Dashboard". MISO Energy. June 26, 2025. https://www misoenergy.org/engage/MISO-Dashboard/generator-interconnection-queue-improvements/

[14] 2025-11-25_193 FERC ¶ 61,168_Docket No. ER25-3543-000729602.pdf. FERC Order approving MISO's September 2025 request to increase from ten projects to fifteen projects per quarter.

broad geographic interest in expedited resource development[15]. Under the ERAS process GIAs are expected to be executed as early as Q4 2025.

Figure 3-12 – ERAS Timeline



3.2.5. Impact of Regulatory Changes

Recent FERC orders 2023, 2222, and 881 introduce significant changes led by MISO. It also requires transmission providers to evaluate Grid Enhancing Technologies ("GETs") to improve system efficiency These orders may promote more agile, data-driven, and distributed approaches to resource planning in the future, requiring adaptation to evolving grid realities and regulatory requirements.

FERC Order 2023:

Requires MISO and other Regional Transmission Operators to overhaul their generator interconnection processes. It mandates MISO to modernize its generator interconnection process by adopting a "first-ready, first-served" cluster study model, enhancing transparency, and enforcing stricter timelines. It calls for MISO to prioritize commercially viable projects, streamline queue management, and evaluate Grid Enhancing Technologies to optimize transmission capacity. The order also reinforces cost allocation principles, ensuring developers fund necessary upgrades[16]. These reforms aim to reduce interconnection delays, support renewable integration, and align MISO's procedures with

[15]"Board of Directors – System Planning Committee". MISO Energy. June 10, 2025. https://cdn misoenergy.org/06_2025-09-16_SPC_Open_Long%20Term%20Resource%20Adequacy%20%20Interconnection%20Queue%20Update_FINAL717559.pdf., page 6

[16] "Fact Sheet – Improvements to Generator Interconnection Procedures and Agreements". FERC. July 27, 2023. https://www.ferc.gov/news-events/news/fact-sheet-improvements-generator-interconnection-procedures-and-agreements

FERC's national standards. Compliance filings were submitted in April and May 2024, and continuing through 2026. MISO continues to work with stakeholders to enhance transparency and align its processes with FERC's expectations for Transmission Evolution initiatives.

FERC Order 2022:

Issued in September 2020, requires RTOs/ISOs to allow DERs to aggregate and participate in wholesale markets. MISO submitted its second compliance filing in early 2025, which FERC accepted, allowing full market integration of DER aggregators by 2030. Utilities will adapt IRPs by integrating DERs more explicitly into planning models, potentially revising forecasting methods to include aggregated DER impacts, and coordinating more closely with distribution system operators and aggregators. Intermediate steps may allow limited participation under demand response models between 2027 and 2029. MISO is currently upgrading its market platform and settlement systems, with major milestones expected in 2025–2028.[17]

FERC Order 881:

Mandates that all U.S. transmission providers—including RTOs, ISOs, and utilities implement Ambient Adjusted Ratings ("AARs")[18]. This order requires CEI South to develop a Facility Rating Methodologies, ensuring hourly electronic updates of line ratings based on forecasted ambient temperatures, and maintaining secure databases of rating methodologies. This shift enhances grid efficiency by unlocking unused transmission capacity based on real-time weather data.

Overall, Order 881 drives more accurate, cost-effective, and flexible transmission resource planning. Originally set for July 2025, MISO requested and received an extension to December 31, 2028, citing vendor delays and software readiness issues. Despite the delay, stakeholders and FERC encourage MISO to implement components of AARs ahead of schedule to reduce congestion costs and improve reliability.

3.3. Fuel

The thermal units in this analysis are fueled by three main sources: natural gas, coal, and uranium. Fuel forecasts were obtained from a variety of sources in order to capture perspectives from multiple industry experts, allowing CEI South to be more transparent and

[17] "Distribution Energy Resource Task Force (DERTF)". MISO Energy. April 11, 2024. https://cdn.misoenergy.org/2024%20Order%202222%20Compliance%20Framework631391.pdf

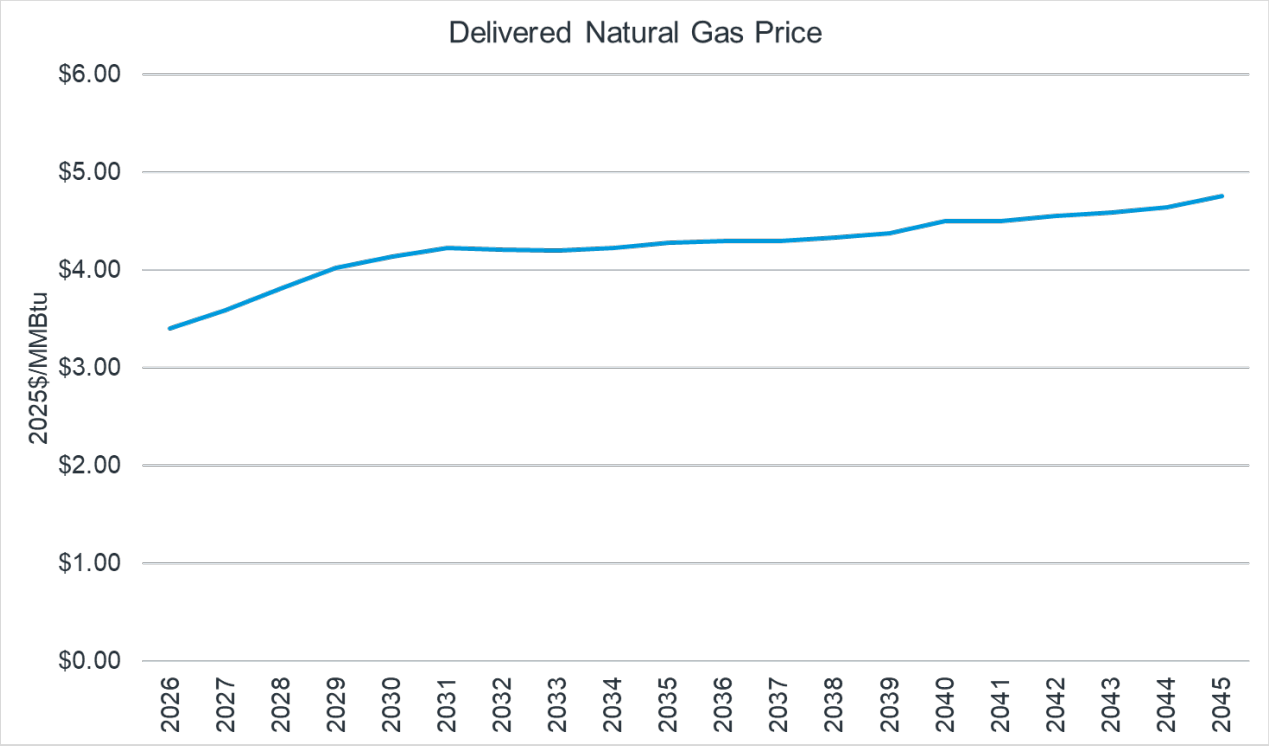
[18] "FERC Rule to Improve Transmission Line Ratings Will Help Lower Transmission Costs". FERC. December 16, 2021. https://www.ferc.gov/news-events/news/ferc-rule-improve-transmission-line-ratings-will-help-lower-transmission-costs

less reliant on a single perspective in the planning process. For natural gas and coal, forecasts from Wood Mackenzie, Hitachi, S&P Global, and EVA were averaged.

3.3.1. Natural Gas

In addition to the sources mentioned above, CEI South utilized NYMEX data to adjust the Henry Hub price based on historical price separation between Henry Hub and delivered gas prices to the CEI South system. Figure 3-13 displays the delivered natural gas price forecast for the Reference Case.

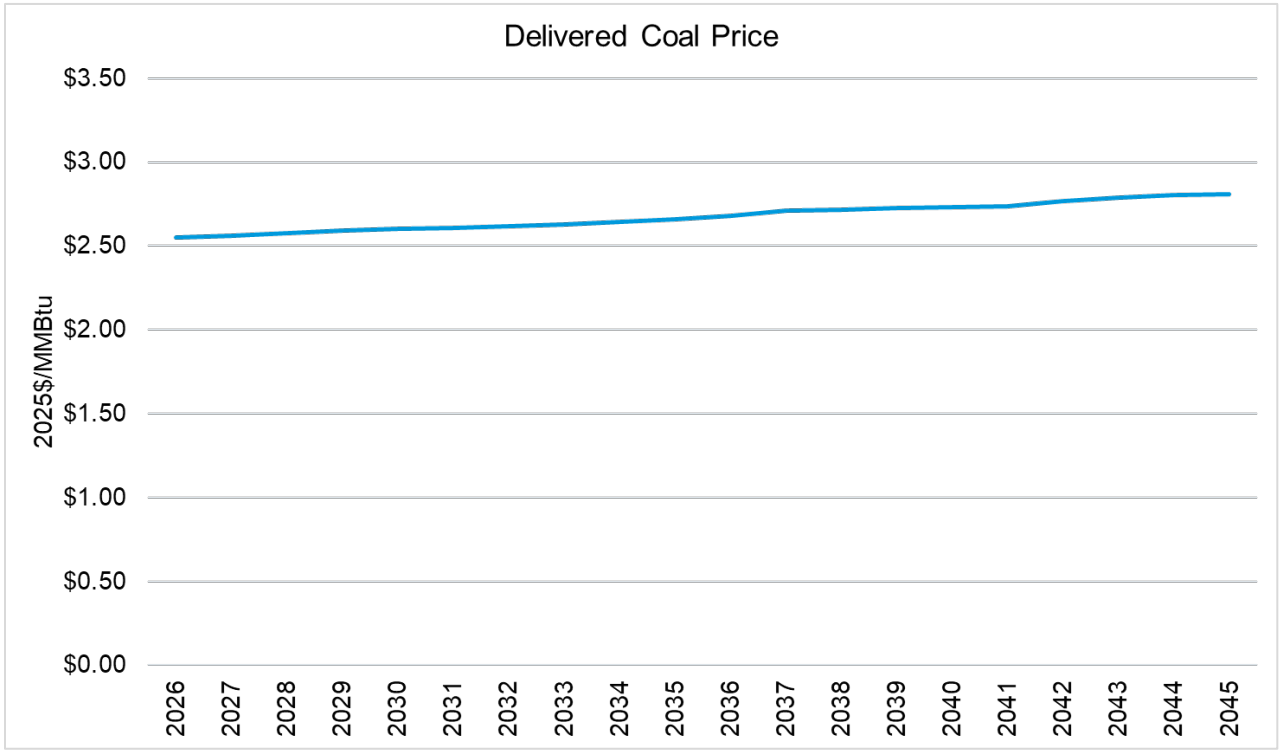
Figure 3-13 – Reference Case Natural Gas Price Forecast (2025$/MMBtu)



3.3.2. Coal

CenterPoint's coal facility is fueled by Indiana-mined coal. Similar to natural gas, a transportation adder based on historical data was included to obtain a price for coal delivered to CEI South. Figure 3-14 displays the consensus coal price forecast for the Reference Case.

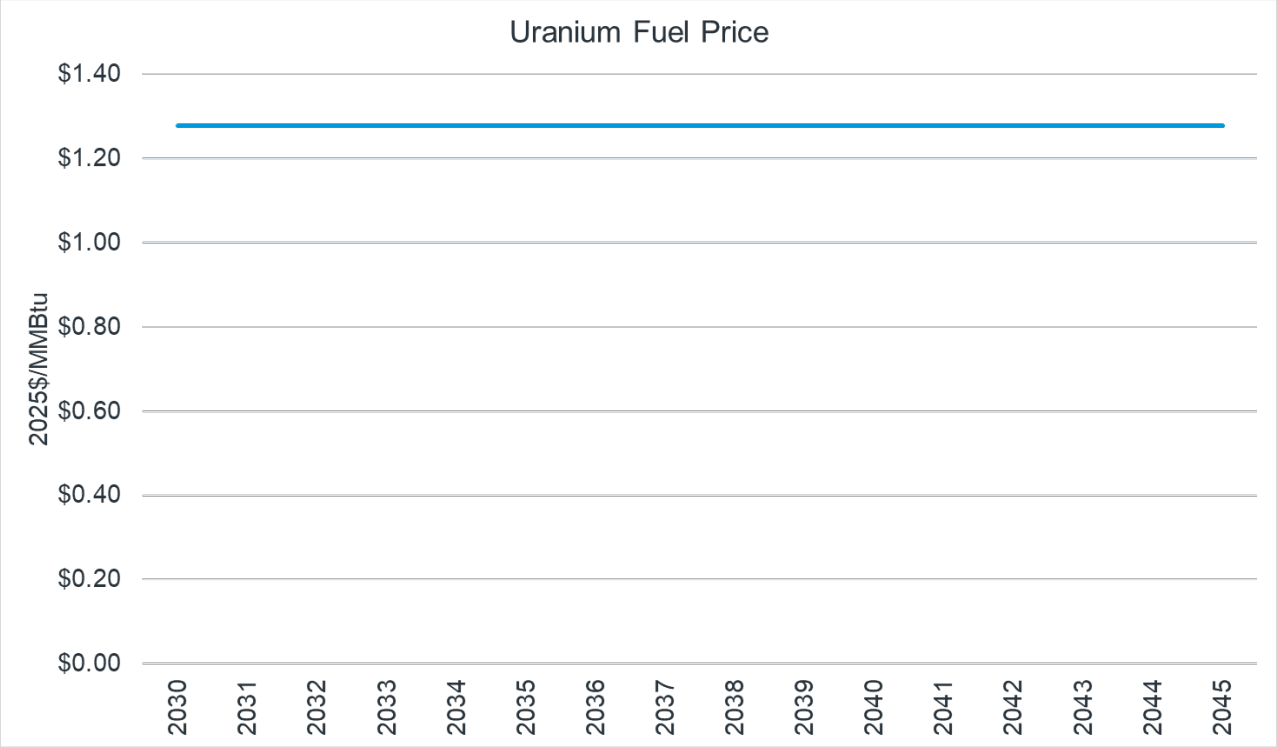
Figure 3-14 – Reference Case Coal Price Forecast (2025$/MMBtu)



3.3.3. Uranium

Nuclear power plants use uranium fuel to produce heat. The uranium price forecast, shown in Figure 3-15, was sourced from the 2024 Annual Technology Baseline published by the NREL[19]. Because uranium is a fuel associated with an emerging technology in NREL's dataset, the forecast begins in 2030 and assumes a constant price throughout the study period.

Figure 3-15 – Reference Case Uranium Price Forecast (2025$/MMBtu)

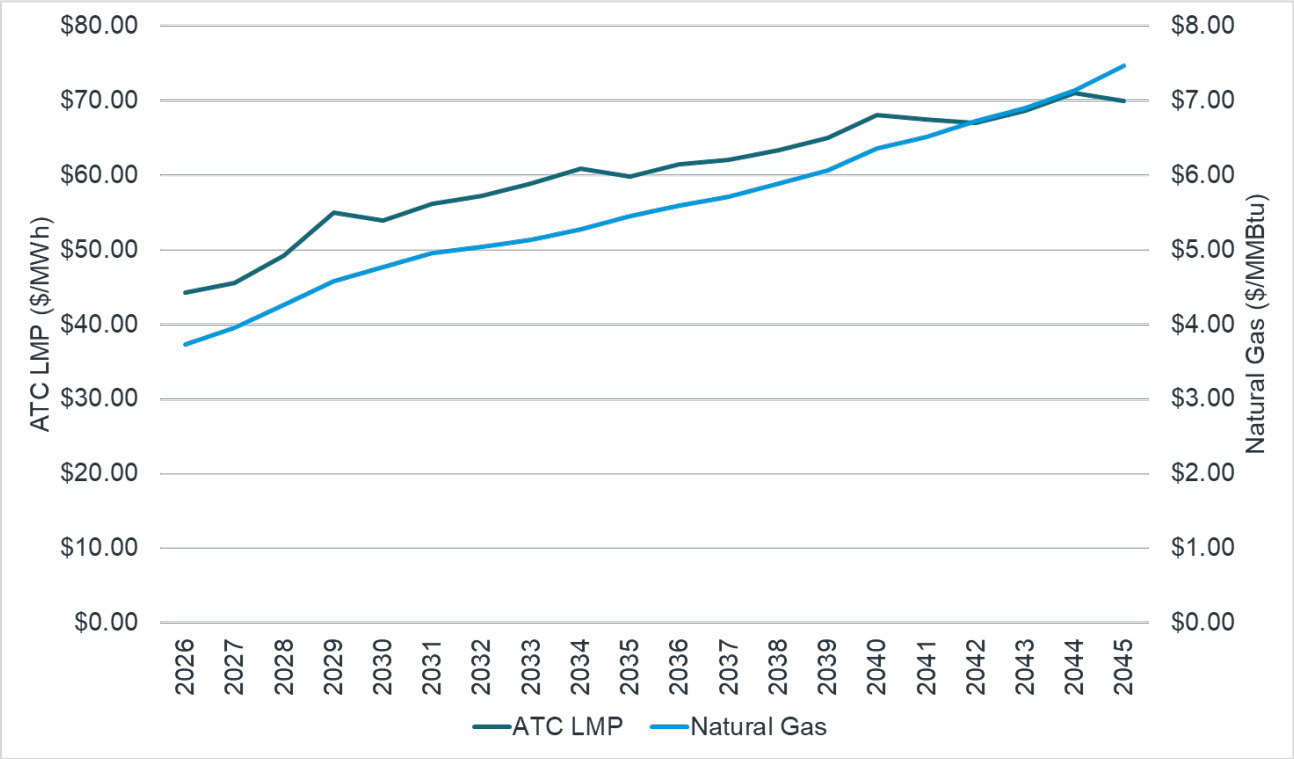


3.4. Power Prices

Energy prices as an input into the IRP model were developed by 1898 & Co. using the EnCompass software. The starting model for the analysis was the national database licensed from Horizons Energy, LLC. Updates to the National Database were made to specifically align the input assumptions with the IRP Scenario assumptions. A summary of around the clock ("ATC") power price forecast can be seen below in Figure 3-16 which also illustrates the macro correlation to natural gas prices over the study period.

[19] The NREL ATB Excel workbook can be found here: https://atb.nrel.gov/electricity/2024/data. Uranium fuel costs were taken from the "Nuclear" tab. The moderate forecast for a small nuclear facility was used.

Figure 3-16 – Reference Case Power Price Forecast (Nominal $)



3.5. Environmental Regulations

The current modeling analysis includes relevant costs primarily focused on evaluation of alternatives to comply with the ELG, 316(b), and ACE rule proxy requirements where applicable. The costs presented below are preliminary screening level estimates used for modeling purposes only. Individual elements of the estimate may go up or down depending on final design specifications, permit requirements, and vendor bids. It should be noted that environmental regulatory requirements represent one of the areas presenting significant uncertainty with respect to the current administration's activities related to regulatory reform and potential future requirements related to greenhouse gas emissions from fossil fuel-fired generating units.

3.5.1. Effluent Limitations Guidelines ("ELG")

F. B. Culley Unit 3 is equipped with dry fly ash and dry bottom ash handling systems, thereby eliminating ash transport water discharges in compliance with the current requirements of the ELG rule. The Spray Dryer Evaporator Zero Liquid Discharge system

has been completed and is online, timely meeting the ELG requirements that are incorporated into the NPDES permit and eliminating the discharge of FGD Wastewater. F.B. Culley Unit 2 still utilizes bottom ash transport water and is slated for retirement on December 31, 2025, in compliance with the requirements of its NPDES permit.

In May 2024, EPA published updated Effluent Limitation Guidelines rule, which contains a provision that requires Zero Liquid Discharge ("ZLD") of unmanaged Combustion Residual Leachate ("CRL") for facilities that do not permanently cease combustion of coal by the end of 2034. This technology is factored into scenarios that include operating Culley Unit 3 on coal past 2034.

3.5.2. Coal Combustion Residuals ("CCRs")

Company continues to close its ash ponds in timely compliance with the requirements of the CCR rule, which was first promulgated in 2015 and has undergone multiple revisions since implementation. The timing of the closures is based on forced closure (i.e., exceedance of Ground Water Protection Standard ("GWPS") and failure of aquifer location restriction) and compliance with the Site-Specific Alternatives to Initiate Closure plans that were submitted to U.S. EPA under the requirements of the CCR Part A rule. The base cost for the closures does not change regardless of future generation and closure cost for CCR units is not part of the IRP modeling.

3.5.3. Greenhouse Gas Regulations

As noted previously, the federal regulation of greenhouse gases is an area of significant uncertainty stemming from years of litigation and continual swings in requirements between federal administrations. In June 2019 the first Trump administration finalized the ACE rule, which replaced the 2015 Clean Power Plan (a cap and trade program which sought to lower CO_2 emissions from existing power plants by 30% from 2005 levels) with a requirement that existing fossil fuel-fired generating units meet certain efficiency targets. This rule was referred to as the Affordable Clean Energy Rule ("ACE"). The ACE rule was repealed and replaced by the Biden administration's New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units which was effective on July 8, 2024 (Biden Rule). The Biden Rule is currently in effect; however, on June 17, 2025, the second Trump administration has proposed revisions to the Biden Rule. The current proposal would rescind greenhouse gas emissions targets as they related to fossil fuel-fired EGUs, or in the alternative declare carbon capture and sequestration technology. We believe it is unlikely that we will cease to have any regulatory requirements applicable to greenhouse gas emissions from fossil fuel-fired generating units, so CEI South used ACE as a proxy for

carbon legislation in the reference case (see Figure 3-17). Since F.B. Culley 2 is planned for suspension in 2025, no ACE costs were included for this unit.

Figure 3-17 – ACE Proxy Cost

Unit	Total ACE Update Cost (2025$)
F.B. Culley 3	$32 Million

3.5.4. 316(b)

In 2014 EPA issued its final rule regarding Section 316(b) of the Clean Water Act which seeks to mitigate impacts to aquatic life from large water intake structures. The rule establishes requirements for Cooling Water Intake Structures ("CWIS") at existing fossil fuel-fired generating facilities and applies to the Culley generating facility which employs a once-through cooling water system. The 316(b) rule requirements are implemented through the facility's NPDES permit. Company is currently in the final stages of finalizing the selected technology and estimated costs for compliance at the Culley facility is included in the current IRP modeling scenarios as appropriate.

3.6. Tax Incentives

3.6.1. Inflation Reduction Act ("IRA") and One Big Beautiful Bill Act ("OBBBA")

The IRA was signed into law by President Biden on August 16, 2022. The $500 billion legislation was intended to mitigate the effects of climate change by offering numerous incentives to promote investment in clean energy production and included tax credits for households to offset energy costs. A substantial portion of the funding was directed toward reshaping the nation's energy infrastructure. Key provisions of the IRA included the extension of wind Production Tax Credits ("PTC"), the allowance of solar production tax credits, the continuance of solar Investment Tax Credits ("ITC"), funding for energy efficiency, the introduction of the ITC for stand-alone battery storage, and incentives for electric vehicle charging.

Vast portions of the IRA were eliminated with the passage of the OBBBA, signed into law on July 4, 2025. The legislation repeals most clean energy provisions and includes eligibility conditions that effectively disqualify clean energy projects that are not shovel-ready. The OBBBA includes a dual-condition eligibility test; a project must begin construction (start physical work or incur at least 5% of total project costs and maintain continuous progress)

within 60 days of the bill's enactment and be placed into service by December 31, 2028. Projects that do not meet these criteria will no longer be eligible for the PTC or ITC. Additionally, the law removes consumer energy incentives for distributed energy adoption after 2025 and repeals electric vehicle tax credits after 2026. Credits for carbon capture and storage, clean fuels credit, and zero emissions nuclear power production credits remain in place.

These updates to the renewable tax credits were incorporated into the modeling assumptions based on the description of the scenarios. In the Reference Case and Alternate Reference Case, solar ITC and wind PTC eligibility expires at the end of 2029, while nuclear and storage resources retain their full credits through 2033, followed by declining values in 2034 and 2035. Figure 3-18 shows the updated tax credits included in the reference and alternate reference case scenarios.

Figure 3-18 – Reference and Alt Reference Scenario Tax Credits

		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Solar	ITC	30%	30%	30%	30%	30%	0%	0%	0%	0%	0%	0%	0%
Storage	ITC	30%	30%	30%	30%	30%	30%	30%	30%	30%	23%	15%	0%
Wind	PTC	100%	100%	100%	100%	100%	0%	0%	0%	0%	0%	0%	0%
Nuclear	PTC	100%	100%	100%	100%	100%	100%	100%	100%	100%	75%	50%	0%

For the High Regulatory and Alternate High Regulatory worldviews, the previous legislation governing tax credit eligibility was retained. Under these scenarios, solar and storage resources qualify for the full ITC through the end of 2032 and wind resources qualify for full PTC through 2029, with a reduced credit from 2030 through 2032. Figure 3-19 shows the pre-OBBBA tax credits that are included in the High Regulatory and Alternate High Regulatory scenarios.

Figure 3-19 – High Reg and Alt High Reg Scenario Tax Credits

		2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036
Solar	ITC	30%	30%	30%	30%	30%	30%	30%	30%	0%	0%	0%	0%
Storage	ITC	30%	30%	30%	30%	30%	30%	30%	30%	0%	0%	0%	0%
Wind	PTC	100%	100%	100%	100%	100%	100%	100%	100%	0%	0%	0%	0%

3.7. Resource Options

3.7.1. Current Resource Mix

Thermal generating units are often categorized as either base load, intermediate, or peaking units. This characterization has more to do with the economic dispatch of the units and how much service time they operate rather than unique design characteristics, outside of intermittent renewables, which do not have variable fuel costs. Base load units generally have the lowest energy costs per kWh and tend to operate most of the time, thereby providing the base of the generating supply stack after intermittent renewables, which operate as available and typically unrelated to market prices and conditions. The supply stack is the variable cost of production of power by each generating unit, stacked from least cost to most cost. In general, units that cost less to run are dispatched before units that cost more.

F.B. Culley 3 has historically operated as a base load unit but with low natural gas prices and the introduction of more renewables into the market, capacity factors have decreased. F.B. Culley 3, CEI South's last coal unit that it plans to operate past 2025, more recently has operated more like an intermediate unit, particularly in shoulder months during Spring and Fall seasons. Intermediate units may cycle on and off frequently and may sit idle seasonally. CEI South's current peaking units have relatively high energy costs per kWh and are typically only started when energy demand exceeds 24/7 baseload capacity. Currently, CEI South's small gas turbines, units 3 and 4, are dispatched during these peak periods to assure reliability. These small peaking units may only run for a few hours and remain idle for long periods of time until called on. Most recently, CEI South has added two new combustion turbines and one solar array. These assets will provide necessary support for grid stability following the retirement of A.B. Brown coal units 1 and 2 in 2023.

3.7.1.1. Generation

CEI South's current and expected generation mix consists of approximately 1,807 MW of installed capacity. This capacity currently consists of approximately 360 MW of coal-fired generation from F.B. Culley 2 & 3. Following the suspension of F.B. Culley 2, which is scheduled for the end of 2025, the installed capacity of coal-fired generation in CenterPoint's fleet will drop to 270 MW. CEI South's existing generation also includes 624 MW of gas fired peaking generation, 3 MW of renewable landfill gas generation, 397 MW of wind procured through Power Purchase Agreements ("PPAs"), 391 MW of solar (with 150 of that total coming from PPAs), and a 1.5% ownership share of Ohio Valley Electric Corporation ("OVEC") which equates to approximately 32 MW.

3.7.1.2. Existing Resources

Figure 3-20 references both Installed Capacity ("ICAP") and Seasonal Accredited Capacity ("SAC"). Installed capacity is also referred to as nameplate capacity. Seasonal accredited capacity is the amount of capacity that can be relied upon to meet load during tight operating hours. MISO now uses SAC for planning purposes. The SAC accreditation recognizes all resources are not equally reliable or, in some cases, capable of achieving their design output. MISO uses a three-year operating history and a weather normalized capability verification to determine the SAC accreditation of each unit. CEI South used historical data and MISO's current methodology for thermal units to determine seasonal accreditation values along with the MISO seasonal planning reserve margin requirements (7.9% for summer, 14.9% for fall, 18.4% for winter, and 25.3 in spring[20]) in the current IRP. This information was utilized to help ensure all portfolios met MISO obligations on a seasonal basis.

Figure 3-20 – CEI South's Owned Generating Units (2026/2027 Planning Year)[21]

Unit	Installed Capacity (MW)	Summer - Seasonal Accredited Capacity (SAC - MW)	Fall - SAC (MW)	Winter -SAC (MW)	Spring - SAC (MW)	Primary Fuel	Initial Service Year
F.B. Culley 3	270	181.4	248.8	231.6	269.6	Coal	1973
A.B. Brown 3	80	67.4	72.1	91.7	75.8	Gas	1991
A.B. Brown 4	80	70.5	67.3	89.2	80.3	Gas	2002
A.B. Brown 5	232	209.1	195.1	183.5	195.1	Gas	2025
A.B. Brown 6	232	209.1	195.1	183.5	195.1	Gas	2025
Posey Solar	191	85.0	66.7	48.7	89.2	Sun	2025
Troy Solar	50	22.25	17.5	12.75	23.35	Sun	2021
Blackfoot	3	N/A	N/A	N/A	N/A	Landfill Gas	2009
Oak Hill Solar	2	N/A	N/A	N/A	N/A	Sun	2018
Volkman Rd. Solar	2	N/A	N/A	N/A	N/A	Sun	2018

[20] "Loss of Load Expectation Working Group (LOLEWG)". MISO Energy. October 24, 2024. https://cdn.misoenergy.org/20241024%20LOLEWG%20Item%2003%20PY%202025-2026%20LOLE%20Study%20Results654956.pdf, Slide 2

[21] CEI South plans to place F.B. Culley 2 into suspension by December 31,2025.

3.7.1.2.1. Energy Efficiency

CEI South utilizes a portfolio of Demand Side Management ("DSM") programs to achieve demand reductions and energy savings, thereby providing reliable electric service to its customers. CEI South's DSM programs have been approved by the Commission and implemented pursuant to various IURC orders over the years.

Since 1992, CEI South has operated a Direct Load Control ("DLC") program called Summer Cycler which can reduce residential and small commercial air-conditioning and water heating electricity loads when needed during summer peak hours. A description of the program is included below. While this technology can still be reliably counted on to help lower demand for electricity at times of peak load, this aging technology will be phased out over time. CEI South's Summer Cycler program has served CEI South and its customers well for more than three decades, but more recent technology is now making the program obsolete. Between 2010 and 2024, CEI South's DSM programs reduced demand by approximately 97,000 kW and provided annual incremental gross energy savings of approximately 521,000,000 kWh.

Figure 3-21 below outlines the estimated program penetration on an annual basis since CEI South programs began in 2010. Gross cumulative savings below, are shown as a percent of eligible retail sales. Note that historical DSM savings are implicitly included in the load forecast as these savings are embedded in the historical sales data.

Figure 3-21 – Gross Cumulative Savings[22] [23]

Year	Eligible Retail Sales (GWh)	Gross Cumulative Savings (GWh)	Gross Cumulative Savings (GW)	Percent of Sales Achieved (Cumulative)
2010	5,617	2.53	0.00051	0.04%
2011	5,595	19.40	0.00331	0.35%
2012	5,465	66.95	0.01212	1.23%
2013	5,459	128.64	0.02416	2.36%
2014	3,499	175.98	0.03215	5.03%
2015	3,224	202.82	0.03698	6.29%
2016	3,256	236.40	0.04222	7.26%
2017	3,281	268.86	0.04861	8.20%
2018	3,491	309.28	0.05624	8.86%

[22] Gross Cumulative Savings are adjusted for Residential Behavioral, which has a one-year program life therefore not cumulative in nature.
[23] Statewide DSM programs ended in 2013. The drop in eligible sales is attributed to industrial customers opting out of DSM programs effective July 1, 2014.

Year	Eligible Retail Sales (GWh)	Gross Cumulative Savings (GWh)	Gross Cumulative Savings (GW)	Percent of Sales Achieved (Cumulative)
2019	3,135	352.76	0.06455	11.25%
2020	3,176	398.16	0.07411	12.54%
2021	3,174	428.56	0.08102	13.50%
2022	3,209	454.79	0.08638	14.17%
2023	3,265	490.01	0.09265	15.01%
2024	3,285	521.50	0.09717	15.87%

3.7.1.2.1.1.1. 2025-2027 Plan Overview

Consistent with the 2022/2023 IRP, the framework for the 2025-2027 EE Plan was modeled at a savings level of 1.1% of retail sales adjusted for an opt-out rate of 77% of eligible load. Below is a listing of residential, as well as commercial and industrial programs offered in 2025-2027. For full program descriptions including the customer class, end use of each program and participant incentives provided by the programs, please refer to the 2025-2027 EE Plan detail found in the *Technical Appendix Attachment 3.4 CEIS Electric 2025-2027 DSM Plan*.

Residential Programs

- Residential Prescriptive
- Residential Midstream
- Home Energy Assessment
- In Store Discount
- Multi Family Energy Solutions
- Community Connections
- Residential New Construction
- Income Qualified Weatherization
- Energy Efficiency Store (Marketplace)
- Residential Behavior Savings
- Smart Cycle (“DLC Change Out”)
- Bring Your Own Thermostat (“BYOT”)
- Conservation Voltage Reduction (“CVR”) Residential

Commercial and Industrial Programs

- Commercial and Industrial Prescriptive
- Commercial and Industrial Midstream
- Commercial and Industrial Custom

- Small Business Energy Solutions
- Building Optimization
- Conservation Voltage Reduction ("CVR") Commercial

The 2025-2027 plan was included as an existing resource in the 2025 IRP and has an assumed average measure life of 13 years. The table below shows the amount of net savings included in the IRP as a resource (gross savings can be found in *Technical Appendix Attachment 3.4 CEIS Electric 2025-2027 DSM Plan*).

Figure 3-22 – Energy Efficiency Savings[24]

	2025		2026		2027	
Sector	Net kWH Energy Savings	Net kW Demand Savings	Net kWH Energy Savings	Net kW Demand Savings	Net =kWH Energy Savings	Net kW Demand Savings
Residential	13,259,256	7,818	14,814,287	8,854	14,732,977	7,874
C&I	19,224,000	2,528	21,344,251	2,982	21,570,750	2,757
Total	**32,483,256**	**10,345**	**36,158,538**	**11,836**	**36,303,727**	**10,631**

3.7.1.3. Demand Response

CEI South's tariff currently includes five Demand Response ("DR") programs:

- Direct Load Control Rider ("DLC"),
- Thermostat Load Control Rider ("TLC"),
- Two interruptible options for larger customers (Interruptible Contract Rider and Interruptible Option Rider),
- Aggregation Demand Response Rider ("ADR") and
- MISO Demand Response Rider.

Demand response programs allow CEI South to curtail load for reliability purposes. CEI South's MISO DR tariff and interruptible tariffs have no customers currently enrolled and registered with MISO. CEI South has recently contracted a third-party DR aggregator from the All-Source RFP to begin a DR aggregation program based on CEI South's customer load and industry demographics.

[24] Gross Cumulative Savings are adjusted for Residential Behavioral, which has a one-year program life therefore not cumulative in nature.

3.7.1.3.1. Current DLC (SUMMER CYCLER)

The DLC program provides remote dispatch control for residential and small commercial air conditioning, and electric water heating through radio-controlled load management receivers. Under the program, CEI South compensates customers in exchange for the right to initiate events to reduce air-conditioning and water-heating electric loads during summer peak hours. CEI South can initiate a load control event for several reasons, including to balance utility system supply and demand, to alleviate transmission or distribution constraints, or to respond to load curtailment requests from MISO.

CEI South manages the program internally and utilizes outside vendors for support services, including equipment installation and maintenance. Prospective goals for the program consist of maintaining load reduction capability and program participation while achieving high customer satisfaction. CEI South also utilizes an outside vendor, The Cadmus Group, to evaluate the DLC program and provide unbiased demand and energy savings estimates.

In 2024, Cadmus predicted that the DLC Program was capable of generating approximately 8 MWs of peak demand savings from residential air-conditioning load control and residential water heating load control during MISO load curtailment events during the summer season. This figure will continue to decrease over time with the increasing occurrence of switch failures.

Until recently, DLC switches have been the default choice for residential load control programs. CEI South has had a DLC program since the early 1990's and as of 2024 had approximately 16,000 residential customers with 22,250 switches participating in the program. However, with the advent of smart thermostats and the myriad of benefits they offer for both EE and DR, CEI South has begun replacing DLC switches with smart thermostats, and the DLC program is closed to new customers as of February 13, 2025.

3.7.1.3.2. Current Interruptible Load

CEI South makes available a credit for qualified commercial and industrial customers to curtail demand under certain conditions. CEI South previously had three customers who were participating for a total demand reduction of approximately 31 MW. MISO issued a curtailment on June 10, 2021. CEI South's largest interruptible customer at approximately 30 MW elected to no longer participate in the interruptible tariff after the event. CEI South worked with stakeholders to help update its interruptible tariffs to streamline language, open them up to a wider number of potential participants, and bring in line with MISO's on-going updates to the Load Modifying Resource ("LMR") rules to derisk this segment of resources. CEI South requested and received approval from the Commission to update these tariffs

accordingly in its most recent rate case in Cause No. 45990. Even with these updates, CEI South still has no customers on the tariff registered as a resource with MISO. See section 3.7.1.3.4 for more information on how CEI South is working to partner with customers to maximize its demand response potential with this segment of C&I customers.

3.7.1.3.3. SMART THERMOSTATS

CEI South launched its pilot Smart Wi-Fi Thermostat program in 2016, by installing 2,000 smart Wi-Fi enabled thermostats in homes in its service territory. As an alternative to DLC switches, smart thermostats can optimize heating and cooling of a home to reduce energy usage and control load while learning from occupant behavior/preference, adjusting Heating, Ventilation and Air Conditioning ("HVAC") settings. Evaluation results are showing significantly more load reduction delivered by smart thermostats than DLC switches. As such, CEI South has designed a program to replace switches with smart Wi-Fi thermostats, a strategic option for cost-effective load control. The Smart DLC Change-out program focuses on residential single-family homes and apartment dwellers. By installing connected devices in customer homes rather than using one-way signal switches, CEI South will be able to provide its customer base deeper energy savings opportunities and shift future energy focus to customer engagement. This change-out program is reflected in IRP modeling.

CEI South also launched the Bring your Own Thermostat program as a DR program. The BYOT program is a further expansion of the Residential Smart/Wi-Fi thermostat initiative. The 2025-2027 Plan provides for approximately 1,430 kW demand each year from the BYOT program based on approximately 1,300 participants each year. BYOT allows customers who have or will purchase their own device from multiple potential vendors to participate in the Thermostat Load Control program. By taking advantage of two-way communicating smart/Wi-Fi thermostats, BYOT programs can help utilities reduce acquisition costs for load curtailment programs and improve customer satisfaction. BYOT allows the utility to avoid the costs of hardware, installation and maintenance associated with transitioning to a smart thermostat. Through the use of smart/Wi-Fi enabled thermostats, the utility can remotely verify how many customers are connected to the network at any given time and determine which thermostats are participating in DR events. Smart thermostat DR programs provide approximately 1 kW per thermostat in load reductions during a DR event.

3.7.1.3.4. Aggregation Demand Response

CEI South received approval to launch the Aggregation Demand Response program in Cause No. 45590. CEI South recently executed a contract with a third-party aggregator for C&I customers which allows the third-party aggregator to provide customers with a

customized energy reduction plan specific to customer's needs based on customer type, such as the following: commercial office building, public school systems, and manufacturing. Aggregators often have the metering and controls technology to allow customers to see and manage their load reduction in real time.

CEI South has included 12 MWs in 2026 ramping up to 25 MWs in 2027 through 2045 based on a market potential analysis during the bidding process. CEI South is one of the first utilities to offer a new Aggregation program in Indiana within approximately the last 10 years. CEI South put this program in place in recognition of stakeholder interest, providing more optionality for C&I customers than CEI South alone can provide.

Aggregation provides long-term affordability by allowing participating customers to earn payments, improve resilience by allowing customers to receive advance notification of grid stability issues, protecting facilities from potential power outages, and supporting the community by helping to maintain reliable, low-cost energy. Aggregation allows for energy industry experts to work with customers to define strategies that leverage existing assets, manage enrollment and execution, and helps maximize revenue for participants.

3.7.2. Potential Future Resource Options

CEI South evaluated a broad range of supply-side technologies, including natural gas, renewable energy, storage technologies, and advanced nuclear. Operational inputs for all supply-side resources were developed from the technology assessment conducted by 1898 & Co., while capital costs were primarily sourced from CEI South's 2024 All-Source RFP results to reflect current market conditions. Where RFP data was not available, capital costs from the technology assessment were used, unless otherwise noted. Detailed information for the All-Source RFP and the technology assessment can be found in *Technical Appendix Attachments 2.1* and *2.2 (Confidential)*, respectively.

The following section details supply-side resource options including conversion opportunities at existing sites, followed by new natural gas, renewables, advanced nuclear, and storage technologies. Then, demand-side resources are outlined including Energy Efficiency and Demand Response programs. Finally, innovative rate designs are also considered.

3.7.2.1. Existing Site Conversions

CEI South evaluated two existing sites, F.B. Culley 3, and A.B. Brown 5 and 6, for potential conversion of existing units to provide additional capacity and energy to meet system needs. F.B. Culley 2 interconnection replacement was also explored in this IRP.

F.B. Culley 2:

At the F.B. Culley 2 site, three power generation technologies were evaluated: reciprocating engines, aeroderivative engines, and storage. The option to let the interconnection agreement at F.B. Culley 2 expire without reuse was also considered. The three resource types were selected based on available space at the site, available infrastructure, regulations on timing of a replacement resource, and CEI South's system needs. Operational parameters of all stated resource options, as well as the capital costs of the natural gas resources, were sourced from the technology assessment. The capital investment of a storage resource at the F.B. Culley 2 site was informed by the 2024 All Source RFP. The gas transportation costs included in all existing site conversions are for firm gas supply and were informed by vendor and internal estimates. Additional detail surrounding gas transportation costs is given in the *Technical Appendix Attachment 3.5 Gas Pipeline Cost Estimates (Confidential)*. Figure 3-23 displays the operational and financial parameters for these potential resources.

Figure 3-23 – F.B. Culley 2 Potential Future Resource Options

Operating Characteristics and Estimated Costs	Reciprocating Engines	Aeroderivative Engines	Storage
Technology Description	Five 18-MW Engines	Two 50 MW Engines	4-Hour Lithium-Ion Storage
Base Load Net Output (MW)	91.5	104.4	90
Base Load Heat Rate (HHV Btu/MWh)	8,340	9,310	N/A
Capital Expenditures (2025$/kW)	$2,650	$3,440	$1,573
Fixed O&M (2025$MM/year)	$2.6	$3.2	$3.2
Gas Transportation Costs (2025$MM/yr)	$10.2	$9.6	N/A
Variable O&M (2025$/MWh)	$4.0	$0.90	N/A

F.B. Culley 3:

At the F.B. Culley 3 site, CEI South analyzed three potential operating pathways for the existing coal plant: continue operating on coal until retirement, convert to operating on natural gas, or co-fire with 40% natural gas. For the first two options, multiple implementation dates were studied. Potential retirement dates for F.B. Culley 3 included December 31, 2031, December 31, 2034, and beyond the planning horizon of this IRP. For conversion to natural gas, start dates of January 1, 2030 and January 1, 2035 were analyzed. Portfolios that included unit conversion also assumed a four-month outage prior to the conversion to allow for necessary construction. The co-fire pathway was modeled with only a single implementation date, primarily driven by the former Clean Air Act 111(d) rule. This includes beginning co-fire operation on January 1, 2030, followed by unit retiring by the end of 2038. These pathways are described in Figure 3-24. Converting F.B. Culley

3 to natural gas will likely result in the unit operating at a lower capacity factor compared to its current coal-fired operation, more similar to that of a peaking resource. The capital costs for this option were developed using vendor estimates, historical data, and internal calculations.

Figure 3-24 – F.B. Culley 3 Potential Future Resource Options

Operating Characteristics and Estimated Costs	Operate on Coal	Conversion to Natural Gas	Convert to Co-Fire
Description of Available Options	• Continue through 2045 • Retire on 12/31/2031 • Retire on 12/31/2034	• Start Gas Fired operation on 1/1/2030 • Start Gas Fired operation on 1/1/2035	• Start Co-Firing operation on 1/1/2030, followed by unit retirement on 12/31/2038
Base Load Net Output (MW)	270	270	270
Base Load Heat Rate (HHV Btu/MWh)	10,560	10,560	10,560
Gas Transportation Costs (2025$MM/yr)	N/A	$15.5MM	$8.9MM

A.B. Brown:

At the A.B. Brown site, the simple cycle gas turbines ("SCGT") placed in service in 2025 (A.B. Brown Units 5 and 6) were evaluated for conversion to a 2x1 combined cycle gas turbine (CCGT), which would improve thermal efficiency, increase generation capacity, and transition the primary use of the facility to be a baseload resource. In this configuration, the exhaust heat from each existing combustion turbine would be captured by a Heat Recovery Steam Generator ("HRSG") which converts the waste heat into steam. This steam then drives a steam turbine generator to produce additional electricity without additional fuel input. Furthermore, this combined cycle configuration was investigated with and without duct firing. In the duct-fired CCGT, natural gas burners are installed in the HRSG to inject supplemental fuel directly into the exhaust steam, raising the temperature and causing the production of more steam. This design provides approximately 150 MW of additional output compared to the non-duct fired configuration. Both options were included to evaluate the tradeoff between increased output and higher capital investments, fuel usage and slightly lower efficiency when operated in this mode. Two implementation dates were considered for this conversion, with the unit being fully operational as a combined cycle at the start of 2030 or 2034. Figure 3-25 depicts the operational and financial parameters of this option.

Figure 3-25 – A.B. Brown Potential Future Conversion Options

Operating Characteristics and Estimated Costs	2x1 F Class SCGT to CCGT Conversion, Unfired	2x1 F Class SCGT to CCGT Conversion, Fired
Base Load Net Output (MW)	735	734
Base Load Heat Rate (HHV Btu/MWh)	6,430	6,440
Duct Fired Net Output (MW)	N/A	893
Duct Fired Heat Rate (HHV Btu/MWh)	N/A	6,830
Capital Expenditures (2025$/kW)	$1,050	$950
Fixed O&M (2025$MM/yr)	$6.2	$6.2
Gas Transportation Costs (2025$MM/yr)	$37.7	$37.7
Variable O&M (2025$/MWh)	$1.5	$1.5

3.7.2.2. Natural Gas

Natural gas power plants are characterized by igniting natural gas and transforming the heat generated from combustion into electrical energy. In addition to the natural gas projects at existing sites, CEI South evaluated a wide range of natural gas technologies including peaking resources such as simple-cycle turbines and reciprocating engines, and intermediate and baseload options such as combined cycle units. This wide range of available natural gas-powered alternatives allow for the evaluation of the tradeoffs between cost effectiveness, reliability, and environmental sustainability.

3.7.2.3. Simple Cycle Gas Turbines

SCGTs utilize natural gas to produce power. The gas turbine (Brayton) cycle is one of the most efficient cycles for the conversion of gaseous fuels to mechanical power or electricity. Typically, SCGTs are used for peaking power due to fast load ramp rates, higher heat rates compared to other technologies and relatively low capital costs. See Figure 3-26 for further details on the simple cycle gas turbine technologies evaluated.

To aid in the evaluation of SCGT, technology estimates were developed to represent the natural gas pipeline costs to supply firm gas service to the unit. An average pipeline cost (in dollar per MW) was developed from the F.B. Culley and A.B. Brown site estimates and then applied to the maximum capacity of all evaluated generic thermal resources. More detail on the estimated gas transportation costs is given in the *Technical Appendix Attachment 3.5 Gas Pipeline Cost Estimate (Confidential)*.

Figure 3-26 – Simple Cycle Gas Turbine Technologies

Operating Characteristics and Estimated Costs	1xF-Class SCGT	1xJ-Class SCGT
Base Load Net Output (MW)	235	426.4
Base Load Net Heat Rate (HHV Btu/kWh)	9,930	8,940
Base Project Costs (2025$/kW)	$1,520	$1,190
Fixed O&M Costs (2025$MM/year)	$2.5	$2.6
Gas Transportation Costs (2025$MM/year)	$17.7	$32.2
Variable O&M (2025$/MWh)	$0.9	$1.2

3.7.2.4. Combined Cycle Gas Turbines

CCGTs utilize natural gas to produce power in a gas turbine which can be converted to electric power by a coupled generator and to also use the hot exhaust gases from the gas turbine to produce steam in a HRSG. This steam is then used to drive the steam turbine and generator to produce electric power. Using both gas and steam turbine (Brayton and Rankine) cycles in a single plant results in high conversion efficiencies and low emissions. Additionally, natural gas can be fired in the HRSG to produce additional steam and associated output for peaking load, a process commonly referred to as duct firing.

For this assessment, seven different configurations were evaluated: a 1x1 F class (unfired and fired), 2x1 G/H class (unfired and fired), 1x1 J class (unfired), and 2x1 J class (unfired and fired), as shown in Figure 3-27 and Figure 3-28. A 1x1 CCGT is configured with one gas turbine and one steam turbine where a 2x1 CCGT is configured with two gas turbines and one steam turbine. General Electric (“GE”) turbines were used as representative CCGT technologies for the operational and financial parameters. The F class is based on the GE 7FA.05 turbine, the J class is based on the GE 7HA.03, and the G/H class is based on the GE 7HA.01 turbine.

Figure 3-27 – Combined Cycle Gas Turbine Technologies (Unfired Configuration)

Combined Cycle Gas Turbines - Unfired				
Operating Characteristics and Estimated Costs	1x1 F-Class	2x1 G/H-Class	1x1 J-Class	2x1 J-Class
Base Load Net Output (MW)	366	848	620	1,254
Base Load Net Heat Rate (HHV Btu/kWh)	6,470	6,260	6,150	6,080
Base Project Costs (2025$/Unfired kW)	$2,271	$1,961	$2,039	$1,695
Fixed O&M Costs (2025$MM/year)	$5.9	$6.7	$6.1	$6.8
Gas Transportation Costs (2025$MM/year)	$27.5	$63.9	$46.7	$94.6
Variable O&M (2025$/MWh)	$1.6	$1.6	$1.6	$1.5

Figure 3-28 – Combined Cycle Gas Turbine Technologies (Fired Configuration)

Combined Cycle Gas Turbines - Fired			
Operating Characteristics and Estimated Costs	1x1 F-Class	2x1 G/H-Class	2x1 J-Class
Base Load Net Output (MW)	365	847	1,244
Total Duct-Fired (Peaking) Net Output (MW)	445	1,034	1,454
Base Load Net Heat Rate (HHV Btu/kWh)	6,490	6,260	6,120
Total Duct-Fired Heat Rate (HHV Btu/kWh)	6,843	6,682	6,569
Base Project Costs (2025$/Fired kW)	$2,518	$2,070	$1,808
Fixed O&M Costs (2025$MM/year)	$5.9	$6.7	$6.8
Gas Transportation Costs ($MM/year)	$33.5	$78.0	$109.7
Variable O&M ($/MWh)	$1.6	$1.6	$1.5

3.7.2.5. Aeroderivative and Reciprocating Engines

Aeroderivative and reciprocating internal combustion engines represent smaller-scale, highly flexible natural gas technologies. Aeroderivative turbines are adapted from jet engine technology, while reciprocating engines are most technologically similar to the engine found in a car. These technologies are well-suited to provide peaking and balancing services during periods of system stress or low renewable output. Both engine types have smaller unit sizes, fast start-up times, and strong operational flexibility when compared to large heavy-frame gas plants. Figure 3-29 explains the operating and financial characteristics of these natural gas units.

Figure 3-29 – Aeroderivative and Reciprocating Engines

Operating Characteristics and Estimated Costs	Aeroderivative Engines	Reciprocating Engines
Base Load Net Output (MW)	52 MW (single engine)	110 MW (six 18-MW engines)
Base Load Net Heat Rate (HHV Btu/kWh)	9,310	8,340
Base Project Costs (2025$/kW)	$3,440	$2,650
Fixed O&M Costs (2025$MM/year)	$2.1	$3.1
Gas Transportation Costs (2025$MM/year)	$3.9	$8.3
Variable O&M ($/MWh)	$0.90	$4.0

3.7.2.6. Renewables

Three renewable technologies were evaluated in the IRP. Those technologies were wind energy, solar photovoltaic ("PV"), and hydroelectric. Our base assumptions for renewable tax credits reflect the updates specified in the OBBBA, including the end of solar and wind tax credits by 2030. Wind resources were modeled to include Production Tax Credits, while solar resources included discounts for the Investment Tax Credit. Under the IRA solar resources have the option to choose between the investment tax credit and the production tax credit. Based on the assumed capacity factor of solar resources, the investment tax credits are anticipated to provide more value and therefore were used in the model.

3.7.2.6.1. Wind

Wind turbines convert the kinetic energy of wind into mechanical energy. Typically, wind turbines are used to pump water or generate electrical energy which is supplied to the grid. See Figure 3-30 for further details on wind technologies evaluated. Aside from the hybrid storage price, the following assumptions were based on the 1898 & Co. technology assessment.

Figure 3-30 – Wind Technologies

Operating Characteristics and Estimated Costs	Wind	Wind + 4-Hour Storage
Base Load Net Output (MW) + (MW for Storage)	200	200 + 100
Base Project Costs (2025$/kW) + ($/kW for Storage)	$2,194	$2,194 + $1,436
Fixed O&M Costs (2025$MM/year)[25]	$10.5	$10.5 + $3.3
Annual Capacity Factor	37%	37%

[25] Variable O&M costs are included in the Fixed O&M estimate in this table.

3.7.2.6.2. Solar

The conversion of solar radiation to useful energy, in the form of electricity, is a relatively mature concept with extensive commercial experience that is continually developing into a diverse mix of technological designs. Solar conversion technology is generally grouped into solar PV technology, which directly converts sunlight to electricity due to the electrical properties of the materials comprising the cell.

PV cells consist of a base material (most commonly silicon), which is manufactured into thin slices and then layered with positively and negatively charged materials. At the junction of these oppositely charged materials, a "depletion" layer forms. When sunlight strikes the cell, the separation of charged particles generates an electric field that forces current to flow from the negative material to the positive material. This flow of current is captured via wiring connected to an electrode array on one side of the cell and an aluminum back-plate on the other. See Figure 3-31 for further details on the solar PV technologies evaluated. Base project costs are informed by the 2024 All Source RFP data where available. Where current market pricing was not available, the technology assessment provided a starting point for cost estimates, which was then tailored to current market conditions as seen in the 2024 All Source RFP.

Figure 3-31 – Solar Technologies

Operating Characteristics and Estimated Costs	10 MW Solar PV	100 MW Solar PV	100 MW Solar PV + 4-Hour Storage
Base Load Net Output (MW) + (MW for Storage)	10	100	100 + 50
Base Project Costs (2025$/kW) + (2025$/kW for Storage)	$2,560	$2,351	$2,504 + $1,626
Fixed O&M Costs (2025$MM/year)[26]	$0.1	$1.2	$1.2 + $1.8

3.7.2.6.3. Hydroelectric

Low-head hydroelectric power generation facilities are designed to produce electricity by utilizing water resources with low pressure differences, typically less than 5 feet head but up to 130 feet. This allows the technology to be implemented with a smaller impact to wildlife and environmental surroundings than conventional hydropower. However, power supply is dependent on water supply flow and quality, which are sensitive to adverse environmental conditions like dense vegetation or algae growth, sediment levels and drought. Additionally, low-head hydropower is relatively new and undeveloped, thus resulting in a high capital cost for the relatively small generation output. See Figure 3-32 for further details on the hydroelectric technology evaluated.

[26] Variable O&M costs are included in the Fixed O&M estimate.

Data from a U.S. Army Corps of Engineers report was used to determine the economically feasible output from the Newburgh and John T. Myers dams located locally on the Ohio River. This report showed that, when taking economics into consideration, both dams combined had an average potential output near 50 MW, which was consistent with tech assessment data used in the analysis. A separate publication from the U.S Army Corps of Engineers showed the estimated construction cost of the Cannelton facility was very close to the assumptions used in the analysis.

Figure 3-32 – Hydroelectric Technologies

Operating Characteristics and Estimated Costs	John T. Myers	Newburgh
Base Load Net Output (MW)	36	22
Base Project Costs (2025$/kW)	$6,901	$6,901
Fixed O&M Costs (2025$MM/year)	$3.8	$2.3

3.7.2.7. Storage

In addition to storage resources paired with renewable technologies, standalone storage was evaluated in this IRP. Short duration Lithium-Ion batteries as well as more nascent long duration technologies were considered. These are summarized in Figure 3-33 and Figure 3-34.

Lithium-ion technology represents a significant majority of utility scale, stationary energy storage projects being developed and installed in the current market. It is the most commercially and technically mature battery storage solution in today's market and is commonly the most cost-effective option for grid-scale applications/use cases with a 1-4 hour discharge duration at rated power. Cost and performance information for these resources are informed by the 2024 All-Source RFP where data was available. Where current market pricing was not available, the technology assessment provided a starting point for cost estimates, which was then tailored to current market conditions as seen in the 2024 All Source RFP.

In effort to consider a wide range of resources, additional emerging energy storage options were also considered as long duration (>4 hours) storage. There are numerous technologies of varying commercial and technical maturity, and while CEI South recognizes the desire for technology diversity, two representative technologies were selected to represent the broader category of long duration energy storage ("LDES"). Compressed Air Energy Storage ("CAES") is a maturing technology that is suitable for large, utility scale projects. While CAES will be limited in implementation depending on

certain geologic characteristics, it generally represents the lower end of today's LDES capital cost range and is therefore a representative technology for resource planning. Additionally, following requests from stakeholders, iron-air energy storage technology was also included in this analysis. The cost and performance estimates for the 100 MW/ 100 Hour storage technology is shown in Figure 3-34.

Figure 3-33 – Lithium-Ion Energy Storage

Operating Characteristics and Estimated Costs	Lithium Ion 50 MW / 200 MWh	Lithium Ion 100 MW /400 MWh	Lithium Ion 100 MW /800 MWh
Base Load Net Output (MW)	50	500	100
Storage Duration (hours)	4	4	8
Round-Trip Cycle Efficiency	85%	85%	85%
Base Project Costs (2025$/kW)	$2,461	$2,273	$4,067
Fixed O&M Costs (2025$MM/year)[27]	$2.0	$3.5	$6.3

Figure 3-34 – Emerging Energy Storage Technologies

Operating Characteristics and Estimated Costs	Compressed Air Representative Technology	Iron Air Representative Technology
Base Load Net Output (MW)	100	100
Storage Duration (hours)	10	100
Round-Trip Cycle Efficiency	68%	34%
Base Project Costs (2025$/kW)	$5,020	$2,840
Fixed O&M Costs (2025$MM/year)[27]	$4.2	$5.0

3.7.2.8. Advanced Nuclear

Nuclear power generation technology has been a dependable, carbon-free power resource in the United States for many decades. In a nuclear power plant, nuclear fission, or the splitting of atoms, occurs. This process creates heat energy which is used to generate steam and spin a turbine, which in turn produces electricity. The nuclear technology considered in this evaluation is a small modular reactor ("SMR") design, which is characterized by compact reactor modules that can be deployed individually or in groups to match system needs. The design incorporates passive safety systems, simplified plant configurations, and high thermal efficiency, which enable lower operating costs and enhanced safety as compared to traditional nuclear generators. The assumed economic and operational data can be found in Figure 3-35.

[27] Variable O&M costs are included in the Fixed O&M estimate.

Although commercial SMR projects are still under development, evaluating a nuclear option provides insight into potential long-term strategies for reliable, sustainable power generation. In the near-term, CEI South views the technology as a future-facing resource rather than a near-term build candidate. For the purposes of this IRP, it is assumed that 2035 is the earliest possible in-service date for this technology.

Figure 3-35 – Advanced Nuclear Technology

Operating Characteristics and Estimated Costs	Nuclear
Base Load Net Output (MW)	100
Base Load Net Heat Rate (HHV Btu/kWh)	11,580
Base Project Costs (2025$/kW)	$15,812
Fixed O&M Costs (2025$MM/year)	$21.6MM
Variable O&M Costs (2025$/MWh)	$2.8

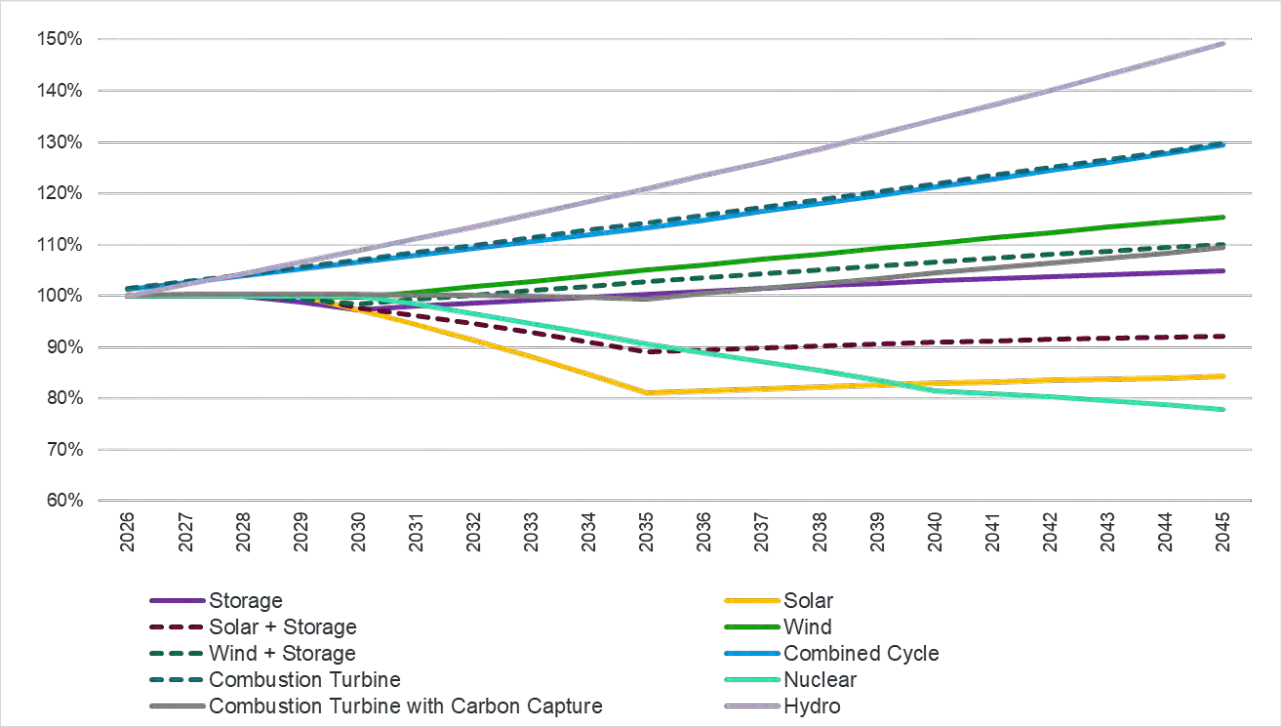
3.7.2.9. Cost Curve Discussion

Forward looking capital cost forecasts were developed and used as part of the 2025 IRP process. Capital cost curves vary based on the generation technology, as shown in Figure 3-36.

Technologies whose capital costs do not decline significantly over the IRP time period, such as wind, natural gas, and coal are generally more mature, while technologies such as advanced nuclear, solar, and hybrid solar plus storage are less mature and expected to experience larger reductions in capital cost over the IRP time period. In the next 20 years, new technological developments and increasing efficiencies for nuclear, solar, and hybrid solar plus storage are expected to decrease capital costs over time. Due to uncertainty associated with these less mature technologies, CEI South relied upon information collected as part of the 2024 All Source RFP as well as cost curves provided by the NREL in their 2024 Annual Technology Baseline ("ATB") Workbook[28] to help project capital costs over the study period.

[28] The NREL ATB Excel workbook can be found here: https://atb.nrel.gov/electricity/2024/data. Capital cost curves were pulled from the "CAPEX ($/kW)" of each included technology.

Figure 3-36 – Forward Looking Capital Cost Curves– Forward Looking Capital Cost Curves



3.7.2.10. Energy Efficiency

In developing a resource plan that integrates demand side and supply side resources, it is incumbent for the energy company to provide the integrating process with a set of DSM options that can be incorporated into the plan. This process aligns with IURC's Rule 170 IAC 4-7-6(b) which states:

> "In describing possible alternative methods of meeting future demand for electric service, a utility must analyze the following resources as alternatives in meeting future electric service requirements:
> (1) Rate design as a resource in meeting future electric service requirements.
> (2) Demand-side resources. For potential demand-side resources, the utility shall include the following:
> (A) A description of the potential demand-side resource, including its costs, characteristics, and parameters.
> (B) The method by which the costs, characteristics, and other parameters of the demand-side resource are determined.
> (C) The customer class or end-use, or both, affected by the demand-side resource.

(D) Estimated annual and lifetime energy (kWh) and demand (kW) savings.
(E) The estimated impact of a demand-side resource on the utility's load, generating capacity, and transmission and distribution requirements.
(F) Whether the program provides an opportunity for all ratepayers to participate, including low-income residential ratepayers."

In addition, this process aligns with IAC 8-1-1.5-3 which requires energy efficiency goals be consistent with an electricity supplier's IRP. Taken together, these jointly supportive requirements direct the energy company to study, similar to supply side resources, available DSM options that may be chosen by the IRP analytical process in arriving at a resource plan. In other words, the level of DSM to be pursued by the energy company should be determined through the IRP process.

3.7.2.10.1. DSM Market Potential Study

The first step in the process is a Market Potential Study ("MPS"). A key purpose of an energy efficiency MPS is to provide energy efficiency planners, decision makers and interested stakeholders with a roadmap to the best opportunities for energy efficiency savings opportunities in the residential, commercial and industrial customer classes. "Energy efficiency potential studies are an effective tool for building the policy case for energy efficiency, evaluating efficiency as an alternative to supply side resources and formulating detailed program design plans. They are typically the first step taken by entities interested in initiating or expanding a portfolio of efficiency programs and serve as the analytic basis for efforts to treat energy efficiency as a high-priority resource equivalent with supply-side options."[29] The results of a potential study pinpoint the energy efficiency measures having the greatest potential for energy savings and identifies the measures that are the most cost effective. Program administrators, regulators and stakeholders can use the results of potential studies to determine the types of programs that should be implemented and how much to invest in energy efficiency as a resource. Potential studies also provide useful information on the benefits and costs of energy efficiency measures and programs from various viewpoints: societally, all customers, the program administrator, program participants and utility rates.

CEI South's MPS completed in 2025 was utilized to both to inform the IRP and support the development of a DSM Action Plan for CEI South, see *Technical Appendix Attachment 3.6 2025 DSM Market Potential Study*. The study included a comprehensive review of current

[29] "Guide for Conducting Energy Efficiency Potential Studies"; Prepared by Philip Mosenthal and Jeffrey Loiter, Optimal Energy, Inc.; https://www.epa.gov/sites/production/files/2015-08/documents/potential_guide_0.pdf ; November 2017; page ES-1

programs, historical savings and projected energy savings opportunities to develop estimates of technical, economic and achievable potential. The study leveraged new primary market research from the *Technical Appendix Attachment 3.7 CEIS 2025 Residential Energy Efficiency Baseline Survey* in the CEI South service area for the saturation of energy-using equipment, building characteristics and the percent of energy using equipment that is already high efficiency. New primary market research from the 2025 study was also leveraged to estimate customer willingness to participate in energy efficiency programs at different incentives levels and targeted end-uses.

Technical potential is the maximum energy efficiency available, assuming cost and market adoption of a technology are not a barrier. Economic potential is the subset of technical potential that is cost effective, meaning the economic benefit outweighs the cost. The economic potential is measured by the total resource cost test, which compares the lifetime energy and capacity benefits to the incremental cost of the energy efficiency measure. While some may contend the full technical or economic potential should be provided as the level of DSM options available in the IRP process, this ignores the fact that 100% of the customers would have to participate. This is not realistic as historical evidence has shown not all customers will adopt a given technology for reasons that range from aesthetic preferences, lack of information about energy efficiency measures, lack of access to capital to perceived comfort concerns. Rather, the potential modeled in the IRP should reflect some consideration of achievability.

To that end, achievable potential considers real-world barriers to encouraging end users to adopt efficiency measures; the non-measure costs of delivering programs (for administration, marketing, analysis and EM&V); and the capability of programs and administrators to boost program activity over time. Barriers include financial, customer awareness and willingness to participate in programs, technical constraints and other barriers the “program intervention” is modeled to overcome. Additional considerations include political and/or regulatory constraints. The potential study evaluated two achievable potential scenarios:

- **Maximum Achievable** Potential estimates achievable potential on paying incentives equal to 100% of measure incremental costs and aggressive adoption rates.
- **Realistic Achievable** Potential estimates achievable potential with CEI South paying incentive levels (as a percent of incremental measure costs) closely calibrated to historical levels but is not constrained by any previously determined spending levels.

It is important to also note the estimates of potential considered in the MPS (and ultimately, in the IRP) exclude potential savings from customers who are eligible and have chosen to actively opt-out of participating in CEI South's energy efficiency programs. In the CEI South service area, approximately 5% of commercial energy sales and 72% of industrial energy sales are associated with customers who have elected to opt-out.

In addition to the energy efficiency potential study, a demand response potential study was also conducted. The methodological approach to the demand response potential study closely mirrored the energy efficiency analysis, with an assessment of the calculation of the demand response technical, economic, and achievable potential. The demand response study analyzed existing programs, such as the Smart Cycle and Residential BYOT programs, as well as potential new programs, such as DR Aggregation, DLC Grid-Enabled Water Heating, DLC Electric Vehicle, Battery Storage, Commercial BYOT, and Critical Peak Pricing rates. The demand response study shows the amount of potential demand that could be realized if customers shift their electric usage from on-peak to off-peak periods.

3.7.2.10.2. Energy Efficiency – IRP Reference Case

Energy Efficiency for the 2025 through 2027 IRP years were informed directly from CEI South DSM Settlement Agreement (2025-2027). These years of energy efficiency were treated as a "going-in" resource in the IRP. For the remaining IRP years (2028-2045), CEI South used the realistic achievable potential identified in the MPS as the starting point for energy efficiency to be modeled in the IRP.

CEI South worked closely with GDS and its stakeholders to formulate an approach to bundling DSM that addressed stakeholder requests, met the IURC rules and fit the EnCompass IRP model requirements. The GDS Team initially provided the energy efficiency IRP inputs across three sector categories (residential, income-qualified, and commercial/industrial). The residential and commercial/industrial bundles were modeled as selectable resources in the EnCompass model. Like 2025-2027 EE levels, the 2028-2045 income-qualified bundle was also treated as a 'going-in' resource as the high costs of program delivery would likely prevent its selection in the IRP, and CEI South anticipates continuing to offer energy efficiency program offerings to their income-qualified customers despite these limitations in cost-effectiveness.

In addition to the sector segmentation, the annual bundles were grouped into three separate time series. The three different vintage bundles: 2028-2030, 2031-2033, and 2034-2045 allow the model to optimize the value of energy efficiency over different time periods. The first two periods were designed to align with the next CEI South DSM program

planning periods, followed by a larger third time series that could provide guidance on DSM selections for the remaining IRP timeframe.

In the process of developing the initial sector-level bundles, two savings adjustments and one cost adjustment were necessary prior to inclusion in the IRP. The first adjustment converted the energy efficiency achievable potential from gross savings to net savings. It is appropriate to model net energy efficiency impacts to remove MWh and MW impacts that would have occurred in the absence of CEI South's programs. Net savings were calculated by applying CEI South's most current Net to Gross ("NTG") ratios to the MPS estimates of gross achievable savings.

The second savings adjustment was to provide the program potential savings at the generator level. The MPS savings are reported at the meter-level. Sector savings were adjusted based on peak system line loss rate of 8.4% to convert savings from the meter level up to the generator level. Figure 3-37 provides a comparison of the total residential, commercial/industrial, and income-qualified sector incremental annual savings from the MPS versus the IRP based on these two adjustments. On the cost side, because the IRP's Capacity Expansion Model does not calculate avoided transmission and distribution ("T&D") benefit associated with DSM measures, the GDS Team provided CEI South with energy efficiency costs that have been adjusted to net out the avoided T&D benefit.

3.7.2.11. Demand Response

CEI South, after working with stakeholders, expanded the number of DR bundles to be included for selection in the IRP Reference Case, from five bundles in the 2022/2023 IRP to thirteen bundles. In the 2025 IRP, to align with MISO's new seasonal structure, cumulative demand MW savings were calculated per the four seasons (Summer, Winter, Spring and Fall).

CEI South included two fixed bundles representing CEI South's DR capabilities for DLC switches on residential air conditioning units and hot water heaters in the CEI South service area. Over the IRP time frame, CEI South anticipates replacing existing DLC switches with smart thermostats that integrate DR capabilities (via the Smart Cycle Program). As CEI focuses on converting switches to smart thermostats, the estimated annual DR savings for the fixed residential air conditioner switch bundle drop from approximately 1.45 MW in 2028, to 0.13 MW by 2045. The estimated annual impacts for the fixed residential water heater switch bundle of DR are approximately 0.41 MW in 2028, decreasing to 0.05 MW by 2045.

Bundles three and four, both selectable resources, represent DR saving capabilities for CEI South's residential DR-enabled smart thermostats. The third bundle represents the Smart Cycle Program, anticipating DR savings from replacing DLC switches with smart thermostats. DR capabilities within the Smart Cycle bundle represents 13.68 MW of peak reduction capabilities in 2028 decreasing to 12.74 MW in 2045. The fourth bundle represents DR savings for customer self-installed DR-enabled smart thermostats in our BYOT program. This bundle represents an additional 12.85 MW of peak reduction capabilities in 2028 increasing to 17.85 MW by 2045.

A fifth bundle also represents DR savings for smart thermostats, but this is a new bundle focused on the commercial sector. CEI South commercial customers wanting to enroll their BYOT thermostats could achieve approximately 0.37 MW in 2028, as historical devices would not yet contribute to DR savings. As participation increases, this bundle shows a potential of 3.56 MW in 2045.

Bundles six and seven, consists of DR savings attributable to a time of use ("TOU") rate option with a critical peak price ("CPP") rate. This program is expected to start in 2026 and build slowly a pilot program through 2030. The sixth bundle, representing residential DR potential from TOU with CPP is expected to achieve approximately 0.57 MW in 2028 and increase to 5.71 MW in 2045. The seventh bundle, accounting for commercial DR savings from TOU with CPP, can achieve around 0.24 MW in 2028 and 2.07 MW in 2045.

Bundles eight and nine, both selectable resources, are new inputs in the 2025 IRP. These bundles represent DR savings for residential and commercial grid-enabled water heaters. Residential grid-enabled water heaters represent an additional 0.63 MW of peak reduction capabilities in 2028 and increases to 5.7 MW in 2045. Commercial grid-enabled water heaters represent an additional 0.31 MW in 2028 and increases to 2.6 MW in 2045.

Per stakeholder requests, two more new bundles for this IRP represent DR savings from EV chargers. One bundle represents residential DR achievable potential and the other represents commercial DR capabilities. Bundle ten, residential EV, represents 0.02 MW in 2028 and increases to 1.2 MW in 2045. The eleventh bundle shows there is very little DR savings potential in CEI South's territory for commercial EV charging, with 0.00003 MW in 2028 increasing to 0.001 MW in 2045.

The final two bundles, also new selectable resources per stakeholder requests, represent inputs for residential battery and commercial battery DR saving potential. The residential battery DR saving inputs provided in bundle twelve, represent 0.03 MW in 2028 and increase to 0.68 MW in 2045. The commercial battery DR potential in bundle thirteen

represents an additional 0.01 MW in 2028 and increases to approximately 0.37 MW in 2045.

3.7.2.12. DSM Resources Optimization Process

Energy Efficiency for the 2026 and 2027 IRP years were informed directly from CEI South DSM Plan (*Technical Appendix Attachment 3.4 CEIS Electric 2025-2027 DSM Plan)* approved in Cause No. 46100. These years of energy efficiency were treated as a "going-in" resource in the IRP. For the remaining IRP years (2028-2045), CEI South used the achievable potential identified in the MPS[30] as the starting point for energy efficiency to be modeled in the IRP.

CEI South worked closely with GDS and its stakeholders to formulate an approach to bundling DSM that addressed stakeholder requests, met the IURC rules and fit the EnCompass IRP model requirements. The GDS Team provided energy efficiency IRP inputs across three sector categories (residential, income-qualified, and commercial/industrial). The residential and commercial/industrial bundles were modeled as selectable resources in the EnCompass model. Like 2026/2027 EE levels, the 2028-2045 income-qualified bundle was also treated as a 'going-in' resource as the high costs of program delivery would likely limit its selection in the IRP, and CEI South anticipates continuing to offer energy efficiency program offerings to their income-qualified customers despite these limitations in cost-effectiveness.

In addition to the sector segmentation, the annual bundles were grouped into three separate time series. The three different vintage bundles: 2028-2030, 2031-2033, and 2034-2045 allow the model to optimize the value of energy efficiency over different time periods. The first two periods were designed to align with the next CEI South DSM program planning periods, followed by a larger third time series that could provide guidance on DSM selections for the remaining IRP timeframe.

In the process of developing the bundles, two savings adjustments and one cost adjustment were necessary prior to inclusion in the IRP. The first adjustment converted the achievable potential from gross savings to net savings. It is appropriate to model net energy efficiency impacts to remove MWh and MW impacts that would have occurred in the absence of CEI South's programs. Net savings were calculated by applying CEI South's most current NTG ratios to the MPS estimates of gross achievable savings.

[30] The IRP inputs used the Enhanced RAP identified in the MPS for the C&I sector, and the RAP for the residential / income-qualified sectors.

The second savings adjustment was to provide the program potential savings at the generator level. The MPS savings are reported at the meter-level. Sector savings were adjusted based on a multiplier of 1.092 to convert savings from the meter level up to the generator level. The table below provides a comparison of the total residential, commercial/industrial, and income-qualified sector incremental annual savings from the MPS versus the IRP based on these two adjustments. On the cost side, because the IRP's Capacity Expansion Model does not calculate avoided T&D benefit associated with DSM measures, the GDS Team provided CEI South with energy efficiency costs that have been adjusted to net out the avoided T&D benefit.

Figure 3-37 – MPS versus Initial IRP Bundles Comparison – Sum of Incremental MWh

	Vintage 1: MPS	Vintage 1: IRP	Vintage 2: MPS	Vintage 2: IRP	Vintage 3: MPS	Vintage 3: IRP
Residential	46,733	45,343	58,227	55,643	310,420	287,399
C&I	76,079	69,786	75,949	69,666	260,052	238,540
IQW	4,640	4,458	6,284	5,895	31,734	29,130

Following an early review of the residential and commercial/industrial energy efficiency savings and costs inputs, the GDS Team further segmented the residential sector savings into high-cost measures (Tier 2), and low/mid cost measure (Tier 1) across each vintage time-series due to concerns that an aggregate residential sector bundle would not get selected. Residential behavioral energy efficiency savings were included in the Tier 1 bundle. Figure 3-38 summarizes the final bundle incremental savings for energy efficiency and associated levelized utility cost per lifetime savings.

In addition to the annual impacts shown in these tables, hourly (or 8,760) shapes that reflect the various measures and end-use mix reflected in each EE resource bundle were provided to CEI South to permit the IRP model to assess the value of energy savings on an hourly basis. These 8,760 shapes were based on residential and commercial end-use load shapes for Indiana from NREL's End-Use Load Profiles database. The ultimate 8,760 shapes are unique for each EE sector and vintage bundle.

Figure 3-38 – Annual MWh EE Savings and Levelized Costs per Lifetime MWh Saved by Bundle

EE Bundles	Enhanced C&I		Res Tier 1 + HER		Res Tier 2		IQW		IQW_HEAR	
	MWh	$/LT-MWh	MWh	$/LT-MWh	MWh	$/LT-MWh	MWh	$/LT-MWh	MWh	$/LT-MWh
2028	22,839	$37.87	10,879	$30.27	2,708	$84.06	1,042	$166.76	293	$332.49
2029	23,439	$38.72	11,893	$31.52	3,257	$85.49	1,120	$174.99	368	$339.69
2030	23,507	$39.63	12,849	$32.69	3,757	$87.40	1,185	$184.76	451	$347.49
2031	24,198	$40.73	13,495	$33.93	4,222	$89.49	1,319	$201.48	539	$355.87
2032	23,406	$41.66	13,938	$35.04	4,673	$91.91	1,347	$213.36	628	$364.92
2033	22,062	$42.43	14,157	$36.20	5,159	$94.47	1,349	$226.10	712	$374.82
2034	23,008	$44.03	15,372	$34.12	6,097	$94.80	1,411	$244.11	786	$385.39
2035	21,998	$45.14	15,487	$35.20	6,499	$97.62	1,377	$257.84	849	$396.47
2036	20,511	$45.88	15,293	$36.12	6,854	$100.57	1,315	$271.91	899	$407.87
2037	19,500	$47.06	15,061	$37.04	7,131	$103.51	1,327	$289.87	936	$419.72
2038	20,898	$49.15	16,246	$36.40	7,624	$106.04	1,565	$268.04	962	$431.29
2039	20,087	$49.89	17,636	$37.43	7,846	$108.39	1,581	$275.56	981	$442.33
2040	19,772	$51.05	17,724	$38.03	7,998	$111.09	1,628	$287.22	993	$452.74
2041	18,773	$51.85	17,550	$38.81	8,004	$113.26	1,569	$295.52	1,000	$462.96
2042	17,685	$52.27	17,369	$39.67	7,996	$115.36	1,520	$303.39	1,005	$472.25
2043	19,434	$50.86	17,234	$40.50	7,904	$118.38	1,539	$316.34	1,000	$480.82
2044	18,923	$51.04	16,825	$40.97	7,639	$121.56	1,477	$322.91	997	$488.83
2045	17,951	$51.39	16,484	$41.61	7,528	$123.45	1,419	$329.24	994	$497.27

3.7.2.13. DSM Improvements Based on Stakeholder Feedback

Review of prior comments from stakeholders and robust stakeholder discussion led to several improvements to DSM modeling since the 2022/2023 IRP. The model has been allowed to make multiple decisions over the 20-year period. The model selects DSM for two three-year periods beginning in 2028 and 2031 and then evaluates the remaining years beginning in 2034 as one collective group. This allows the model to select the appropriate level of DSM based on cost-effectiveness differences and resource needs across the short, mid and long run.

The characterization of the EE and DR bundles included in the IRP modeling was based on a collaborative process with the stakeholders. This led to re-evaluating the sector level budling approach included in the 2022/2023 IRP. CEI South bundled the measures by sector for residential and non-residential consistent with the 2022/2023 IRP to account for

high savings behavioral based efficiency measures to be bundled with low to medium cost measures to help ensure the maximum amount of realistic achievable potential was economically selected. CEI South included the income qualified bundle and added an income qualified HEAR bundle to account for savings through the Indiana Energy Saver program (which will occur outside of DSM filings). CEI South bundled C&I sector savings at an enhanced realistic achievable potential, which allows incentives for some measures to be decreased while increasing incentives for measures that would deliver additional adoption and savings. An improvement to the 2022/2023 IRP was adding more emerging technology measures to be included in bundles across all sectors. Additional sector and end-use specific hourly load shapes were included to more accurately estimate the timing of the energy efficiency impacts throughout the year. Also, based on feedback in the Director's report and working with the OSB, DR bundles were expanded to include six (6) additional DR products as selectable resources even though most were not cost-effective in the MPS.

CEI South also modeled Aggregation as the program is currently being implemented. CEI South explored options and strategies for C&I customers to participate in the program. The aggregator will utilize DR products based on customers industry type and will deploy appropriate curtailment strategies such as process controls and equipment. The aggregator has implemented DR strategies such as lighting controls, thermal energy storage, irrigation controls across utility partners nationwide.

Pricing options modeled in the IRP were based on an opt-in time of use and critical peak pricing design that aligns with CEI South's current pilot program, assuming a broader role out of the rate. Peak time rebates were not modeled as the evaluation, measurement and verification of savings is complex and is specific to each individual customer. Further, such a design would cause CEI South to undergo significant and costly changes to the billing system. Figure 3-39 contains a summary of EE & DR bundles modeled in the 2022/2023 and 2025 IRP with a description of enhancements.

Figure 3-39 – EE and DR Bundle Comparison and Enhancements

Resource Type	2022/2023 Bundles	2025 Bundles	Enhancement
Energy Efficiency	Res Tier 1	Res Tier 1 + Behavioral	Bundled Behavioral with Low/Medium cost Tier 1 to capture large savings high-cost measure
Energy Efficiency	Res Tier 2	Res Tier 2	Introduced an expanded emerging tech measure list for consideration
Energy Efficiency	Res Behavioral		
Energy Efficiency	Res Income Qualified	Res Income Qualified	
Energy Efficiency		Res Income Qualified HEAR	Introduced new bundle to capture impacts of OED IN Energy Saver program, will not be included in utility EE programs
Energy Efficiency	Non-Res Enhanced RAP	Non-Res Enhanced RAP	Modeled the enhanced RAP, where some incentives were decreased for measures and other were increased to drive participation
Demand Response	Res Switches	Res AC Switch	Modeled AC Switch as a "going in" resource, water heater switches were modeled as a separate DR product
Demand Response		Res WH Switch	
Demand Response	Res Smart Cycle & BYOT	Res Smart Cycle	Modeled Smart Cycle as a selectable resource, BYOT thermostats were modeled as a separate DR product
Demand Response		Res BYOT	Bundle was expanded to capture March through November instead of summer only season of June through August
Demand Response		Res WH Grid	Created a new bundle based on stakeholder feedback for grid-enabled water heaters, primarily managed through Wi-Fi
Demand Response		Res EV	Created a new electric vehicle managed charging DR resource using updated saturation & adoption rates based on OSB feedback
Demand Response		Res Battery	Created a new Battery Storage DR resource using updated saturation & adoption rates based on OSB feedback. Ran at multiple incentive levels
Demand Response	Res Rates	Res TOU CPP	Modeled a specific Time-of Use and Critical Peak Pricing resource that aligns with pilot approval in Cause No. 45990

Resource Type	2022/2023 Bundles	2025 Bundles	Enhancement
Demand Response	Non-Res BYOT	Non-Res BYOT	Bundle was expanded to capture March through November instead of summer only season of June through August
Demand Response		Non-Res WH Grid	Created a new bundle based on stakeholder feedback for grid-enabled water heaters, primarily managed through Wi-Fi
Demand Response		Non-Res EV	Created a new electric vehicle managed charging DR resource using updated saturation & adoption rates based on OSB feedback
Demand Response		Non-Res Battery	Created a new Battery Storage DR resource using updated saturation & adoption rates based on OSB feedback. Ran at multiple incentive levels
Demand Response	Non-Res Rates	Non-Res TOU CPP	Modeled a specific Time-of Use and Critical Peak Pricing resource that aligns with Residential pilot approval in Cause No. 45990. Modeling will help inform if TOU & CPP rates are selected for Non-Res
Demand Response	Aggregation	Aggregation	Modeled as a "going in" resource, Aggregation received approval in Cause. No. 45990. CEI South is in the beginning stages of implementing the program and expect 12.5 MWs in 2026 and 25 MWs for 2027-2045

3.7.2.14. Innovative Rate Design

CEI South included innovative rate design in its Preferred Portfolio in its 2022/2023 IRP and the 2025 IRP. Following the IRP, CEI South proposed a CPP with Time of Use ("TOU") pilot in its recent rate case in Cause No. 45990. The Commission approved the pilot, and CEI South has been actively working to develop the program that is set to begin in Q2 2026.

CEI South's approved CPP TOU pilot provides an economic price signal for participating customers to lower their energy usage during peak times through rates. The TOU rate will be available to participating customers in the CEI South pilot between June and September with higher prices during the day and lower prices during nights and weekends. Most likely during times of highest usage, CEI South may call a CPP event, similar to a demand response event where prices are raised to the extent that a reduction in demand is induced. The Automated Metering Infrastructure provides the backbone for this program.

CEI South utilized its continuous improvement and project management teams to work collaboratively with business units to build out the necessary infrastructure to support the pilot. CEI South will work through the pilot over the next one to two years in the hopes of expansion, if successful. An expansion of the CPP TOU pilot is included within this IRP, utilizing indicative amounts developed in its most recent Market Potential Study. The CPP pilot will help inform the potential expansion of an innovative rate design for the commercial sector, included in this IRP.

3.8. Transmission Planning & Distribution Planning

CEI South continually assesses the performance of its electric transmission and distribution systems to ensure safe and reliable service for its customers. The primary goals of CEI South's planning process can be summarized as follows:

- Developing an electric system capable of delivering voltage of constant magnitude, duration and frequency at levels which meet CEI South customers' needs during normal conditions and during a system contingency (loss of a system asset) or set of contingencies;
- Minimizing thermal loadings on transmission and distribution facilities to be within operating limits during normal conditions and to be within emergency limits during contingency conditions;
- Analyzing the dynamic stability of the transmission system under various contingency conditions;
- Ensuring the available system fault current imposed on circuit breakers does not exceed the interrupting capability established by the equipment manufacturer;
- Optimizing the system configuration such that costs (capital and operating) are minimized while maintaining reliability and providing a plan for system upgrades to meet performance requirements;
- Coordinating transmission planning activities in broader regional evaluations with the MISO, ReliabilityFirst ("RF") and neighboring transmission owners;
- Performing an annual assessment of the electric transmission system over a ten-year planning horizon;
- Performing analysis of reactive power resources to ensure adequate reserves exist and are available to meet system performance criteria;
- Analyzing the performance of the distribution system to ensure reliability, adequacy to meet future load growth, DER penetration, and to address age/condition of existing facilities; and
- Ensuring compliance with FERC, NERC and RF Reliability Standards.

3.8.1. Transmission Planning Process

At a high level, CEI South's transmission performance planning models include existing facilities at or above 69 kV, critical system conditions, and study years. Modeled Facilities represent, at a minimum, required upgrades and could include future facilities not yet in service. The models may include distribution circuits and substations. The models aid in analyzing More Probable, Less Probable and Extreme Contingency events. The studied time periods may be for near-term (1 to 5 years) or long-term (6 to 10 years) and for peak and off-peak demand periods; however, the planning horizon may be increased to include transmission or generation plans. Using these models, CEI South may study system growth, generator interconnections, transmission interconnections, Load Serving Entity ("LSE") interconnections, and other studies as needed. Additional planning process details are provided in CEI South's VEC-008, Electric Transmission Planning Criteria (*Technical Appendix Attachments 3.9 VEC-008 Electric Transmission Planning Criteria*).

3.8.2. Existing Transmission System

CEI South's transmission system is comprised of 64 miles of 345 kV lines, 430 miles of 138 kV lines, and 563 miles of 69 kV lines.

The existing Transmission system has interconnections with Duke Energy (345 kV-138 kV-69 kV), Hoosier Energy (161 kV-69 kV), Indianapolis Power and Light Co. (138 kV), Big Rivers Electric Company (345kV-138 kV) and LGE/KU (138 kV). Key interconnection points include three 345 kV interconnections to Duke Energy's system in the area of Duke's Gibson Generation Station and Duff Substation, a 345kV interconnection to Big Rivers' Coleman Substation, a 345 kV interconnection to Big Rivers' Reid EHV Substation, a 138 kV interconnection at AES/IPL's Petersburg Generation Station and 161 kV and 138 kV interconnections to Hoosier Energy, LGE/KU and Big Rivers at CEI South's Newtonville Substation.

3.8.3. Import and Export Capability Assessment

As mentioned above, CEI South's transmission system interconnects with neighboring systems, which provides wholesale import and export capability. Transmission planning studies indicate the existing transmission system provides a maximum import capability of approximately 660 MW in peak demand periods and approximately 750 MW in off-peak demand periods (or approximately 35-40% of peak demand). The current import capabilities were used as a maximum threshold for the energy purchases and sales during the Risk Analysis.

Although CEI South has the capability to offset internal generation with imported capacity, this is not a long-term solution; several factors would influence that capability, including:

- MISO resource adequacy requirements
- Availability of firm capacity
- Transmission path availability
- Operating concerns (post-contingent voltage and line flow)
- Anticipated congestion costs
- Real-time binding constraints

Transmission planning's most recent analysis in its internal long-range planning study looked at a sensitivity on import capability around MISO's Long-Range Transmission Plan ("LRTP") Tranche 2.1 and concluded that the maximum import capability in 2031/2032 would increase to 1,280 MW in the peak demand periods.

3.8.4. Transmission Facilities as a Resource

As part of this year's IRP, CEI South retained 1898 & Co to perform transmission planning analyses evaluating 14 potential resource futures (or "Transmission Study Scenarios"). The resulting study report is included in the *Technical Appendix Attachment 2.3, Transmission Study (Confidential)*.

Study Overview:

The Transmission Study Scenarios included analyzing:

- the retirement of additional coal generation and partial replacement of these retirements with Battery Energy Storage System ("BESS"),
- the addition of a synchronous condenser,
- the addition of an aeroderivative, and
- import from the MISO market.

Each of these cases also included the addition of various levels of renewable resources.

The study (Steady-State analysis only) was performed for the Summer peak, Shoulder (off-peak), and Winter peak demand periods. The five-year and ten-year models utilized were from the latest 2024 MISO Transmission Expansion Plan ("MTEP") model series, which includes future transmission system projects and approved generation interconnections. The ten-year models and transmission scenarios were inclusive of MISO's LRTP Tranche 2.1 portfolio for the region. Additionally, given uncertainty of LRTP project #35 meeting the 2032 in-service date prescribed by MISO, a ten-year sensitivity study removing this project from the models was performed. Modeling parameters for the new renewable resource additions were utilized from the latest cycle of the MISO generation interconnection process. These generation projects included known generation replacement projects and those in final negotiations to execute generation interconnection agreements with MISO. Incorporating these projects ensured the use of

the most up-to-date modeling data for generation resources within CEI South's service area. The analysis incorporated renewable resources already in the MISO queue and modeled within MISO systems, along with the new combustion turbines at the A.B. Brown power plant and the Posey Solar project.

Study Results:
Evaluation of the Transmission Study Scenarios found several issues primarily tied to less generation on the system and a shift of additional issues arising in the Shoulder over the Summer period. Under heavy import conditions, severe voltage reinforcements are required in the Shoulder period. The highest magnitude of reinforcement costs is shown in the Winter period under heavy import conditions. Network upgrades needed to mitigate violations observed across all demand periods ranged from $0 million to $242.6 million depending on the transmission scenario.

Under Shoulder and Summer demand periods in the five-year planning horizon, the Culley G2 BESS or aeroderivative conversions evaluated (Transmission Study Scenarios 6 and 9) required no system reinforcements. Under the same demand periods and planning horizon for Culley G3 BESS conversion (Transmission Study Scenario 7), an additional $22.6 million in thermal and voltage reinforcements were required. When evaluating both Culley G2 and G3 BESS conversion (Transmission Study Scenario 8), additional thermal and voltage violations are produced which increases system reinforcements to $39.9 million. Considering the Culley G2 or G3 BESS conversions under heavy import (Transmission Study Scenarios 11 and 12), the system reinforcements ($56.6 million) required for Culley G2 BESS conversion were less severe than under Culley G3 BESS conversion ($156.8 million). In summary, Culley G2 BESS conversion causes less thermal and voltage impacts than Culley G3 BESS conversion.

The magnitude of system reinforcements was the most significant during the five (5) year Winter demand period, driven by heavy import condition. Heavy import conditions represent transmission scenarios when CEI South's dispatchable resources (F.B. Culley 2 and 3, and A.B. Brown CTs) are offline or unavailable. The reinforcements were estimated between $22.1 million and $242.6 million. Major upgrades on the high-end included rebuilding several transmission lines on the 69 kV and 138 kV system, two (2) additional 345/138 kV transformers at A.B. Brown, a 62.4 MVAr capacitor bank at Culley 69kV sub, and an additional 249.6 MVAr of reactive support spread across CEI South's footprint. The need for additional VAR support across the system is correlated to dispatchable generation being unavailable. A new 40-mile Ameren Norris City (IL) 345kV to A.B. Brown 345 kV line was considered as a potential reinforcement and the

preliminary estimate for this potential project is $136 million, accounting for over half of the $242.6 million mentioned above.

Converting Culley Unit 2 to a Synchronous Condenser was reviewed as an option for VAR support and was determined to be unfeasible due to the design of this particular unit.

IRP Impact:
For capacity expansion modeling, CEI South accounted for uncertainty and price volatility by incorporating conservative estimates for transmission upgrades caused by each potential technology added to the F.B. Culley 2 site. In the case that there are no additional units brought online (Transmission Study Scenario 3), the total upgrade cost was $47.9 million. This value was used to represent the cost of transmission system upgrades if a storage resource was assumed to be placed in service (Transmission Study Scenario 2), as well as in the case that the F.B. Culley 2 site interconnection rights were allowed to expire. Because Scenario 2 represents only the shoulder months, the summer transmission cost from Transmission Study Scenario 3 was used as a conservative estimate of the maximum potential upgrade cost. For the addition of a reciprocating engine or aeroderivative engine at the F.B. Culley 2 site, the highest seasonal costs associated with the Culley G2 aeroderivative (Transmission Study Scenario 4) were estimated at $22.8 million.

3.8.5. Distribution Planning Process

In 2025, Transmission Planning and Distribution Planning teams both completed separate but coordinated Long Range Planning reports which assessed future impacts to each system. Both analyses are coordinated to review load growth, generation changes, and overall system limitations and capabilities.

Furthermore, the Distribution Long Range Planning Report discusses further details on CEI South distribution planning criteria used in system analysis. The public version of the Distribution Long Range Planning Report is included in the *Technical Appendix Attachment 3.8*. Additional planning process details are provided in CEI South's VEC-008, Electric Transmission Planning Criteria, see *Technical Appendix Attachment 3.9.*

3.8.6. Evolving Technologies and System Capabilities

Transmission Capacity Investments:
MISO's 2024 Transmission Expansion Plan identified numerous Multi-Value Projects aimed at increasing regional transmission capacity throughout the central portion of MISO's footprint. MISO's Board of Directors approved these transmission investments in

December of 2024. MISO's approved plan includes transmission capacity additions in CEI South's footprint.

FERC Order 881 - Ambient Adjusted Line Ratings:

CEI South is actively engaged in implementing ambient-adjusted transmission facility ratings (AARs). FERC Order 881 was issued in December 2021 and directed Regional Transmission Operators (such as MISO) and Transmission Owners (such as CEI South) to implement AARs. CEI South actions taken to date include:

- Working collectively with MISO and other Transmission Owners on AAR implementation;
- Conducting monthly internal stakeholder meetings to review implementation status;
- Implementation of an advanced facility ratings database (software that enables the use of ambient adjusted ratings); and
- Completing Energy Management System upgrades required to manage ambient adjusted ratings in real-time operations and communicate those values to MISO.

Historically, transmission facility ratings have been static and only adjusted seasonally. AARs provide additional real-time capacity on transmission facilities when outdoor temperatures are lower. Implementing AARs may reduce or alleviate transmission facility congestion by allowing system operators to apply the increase in the facility's rating, when applicable.

FERC Order 2222 - Distributed Energy Resources:

FERC Order 2222 requires Regional Transmission Organizations ("RTOs") and Independent System Operators ("ISOs") to allow aggregated distributed energy resources ("DERs") to participate in wholesale electricity markets. In an effort to prepare for MISO's implementation of order 2222, CEI South has created an internal task force to ensure compliance with FERC's mandate and MISO's tariff. The task force will coordinate with MISO, IURC, and other authorities to align internal DER processes, registration, system readiness, tariffs, and compliance with reliability and cybersecurity standards.

3.9. Other Modeling Assumptions

3.9.1. Resource Availability

A key model input is the availability of new generation resources, which signals how quickly resources can be brought online. For all scenarios except for those with large load additions (large load sensitivity analysis and the alternate reference case), resource availability assumptions remained constant over the modeling period. As shown in Figure 3-40, renewable build constraints were intentionally aggressive as requested by stakeholders.

Resource availability was also informed by the 2024 All-Source RFP, which indicated that solar and storage were more readily accessible than wind facilities in or near Indiana. Finally, it is important to note that 2035 was identified as the earliest reasonable in-service date for advanced nuclear technology, as informed by the technology assessment.

Figure 3-40 – Resource Availability for Core Scenarios[31]

Technology	1st Year Available	Annual Addition Limit (per Year)	Cumulative Addition Limit (Entire Study Period)
Thermal			
F Class CT	2030	1 Project, 246 MW	1 Project, 246 MW
J Class CT	2030	2 Projects, 874 MW	2 Project, 874 MW
Reciprocating Engine	2030	2 Projects, 220 MW	4 Projects, 440 MW
Aeroderivative	2030	2 Projects, 114 MW	4 Projects, 228 MW
1x1 F Class CC	2032	1 Project, 454 MW	1 Project, 454 MW
1x1 J Class CC	2032	1 Project, 624 MW	1 Project, 624 MW
Renewables			
Solar	2028	4 Projects, 400 MW	18 Projects, 1,800 MW
Solar + Storage	2028	3 Projects, 300 + 150 MW	10 Projects, 500 + 250 MW
Wind	2030	4 Projects, 800 MW	10 Projects, 2,000 MW
Wind + Storage	2030	3 Projects, 600 + 300 MW	5 Projects, 1,000 + 500 MW
Hydro	2032	2 Projects, 58 MW	2 Projects, 58 MW
Storage			
4-hour 50 MW Storage	2028	5 Projects, 250 MW	10 Projects, 500 MW
4-hour 100 MW Storage	2028	5 Projects, 500 MW	10 Projects, 500 MW
8-hour 100 MW Storage	2028	3 Projects, 300 MW	5 Projects, 500 MW
Nuclear			
Nuclear	2035	1 Project, 100 MW	1 Project, 100 MW

For the simulations that included a large load addition, such as the alternate reference case and the large load sensitivity runs, resource build constraints were expanded. As shown in Figure 3-41**,** the constraints for most technologies were expanded to at least twice their base levels. After running the simulations, it was confirmed that these cumulative limits were not binding for either the core scenarios or in the large load addition cases as the model did not select the maximum number of any units.

[31] During a sensitivity analysis, long-duration iron-air storage was not selected in any scenario portfolio. When the resource was included in the capacity expansion model, it consistently produced higher-cost outcomes. Based on these results, it was not carried forward in subsequent capacity expansion modeling.

Figure 3-41 – Resource Availability for Large Load Addition Cases[32]

Technology	1st Year Available	Annual Addition Limit (per Year)	Cumulative Addition Limit (Entire Study Period)
Thermal			
F Class CT	2030	3 Projects, 737 MW	6 Projects, 1,475 MW
J Class CT	2030	3 Projects, 1,311 MW	6 Projects, 2,623 MW
Reciprocating Engine	2030	4 Projects, 439 MW	8 Projects, 878 MW
Aeroderivative	2030	4 Projects, 228 MW	8 Projects, 457 MW
1x1 F Class CC	2032	2 Projects, 908 MW	2 Projects, 908 MW
2x1 G/H Class CC	2032	4 Projects, 3,825 MW	4 Projects, 3,825 MW
1x1 J Class CC	2032	2 Projects, 1,248 MW	2 Projects, 1,248 MW
2x1 J Class CC	2032	4 Projects, 5,477 MW	4 Projects, 5,477 MW
Renewables			
Solar	2028	10 Projects, 1,000 MW	20 Projects, 2,000 MW
Solar + Storage	2028	6 Projects, 600 + 300 MW	20 Projects, 2,000 + 1,000 MW
Wind	2030	8 Projects, 1,600 MW	20 Projects, 4,000 MW
Wind + Storage	2030	6 Projects, 1,200 + 600 MW	10 Projects, 2,000 + 1,000 MW
Hydro	2032	4 Projects, 116 MW	4 Projects, 116 MW
Storage			
4-hour 50 MW Storage	2028	10 Projects, 500 MW	20 Projects, 1,000 MW
4-hour 100 MW Storage	2028	10 Projects, 1,000 MW	20 Projects, 2,000 MW
8-hour 100 MW Storage	2028	6 Projects, 600 MW	10 Projects, 1,000 MW
Nuclear			
Nuclear	2035	2 Projects, 200 MW	2 Projects, 200 MW

3.9.2. MISO Direct Loss of Load Modeling

Beginning with the 2028/2029 Planning Year, MISO is transitioning its capacity accreditation methodology from the SAC construct to the DLOL framework. The DLOL approach represents a significant evolution in how MISO measures resource adequacy, shifting from fixed, technology-specific capacity factors to a probabilistic model based on each resource's performance during periods of highest reliability risk. Under this construct, accreditation is determined by a resource's contribution to avoiding loss-of-load events rather than its average seasonal availability.

[32] During a sensitivity analysis, long-duration iron-air storage was not selected in any scenario portfolio. When the resource was included in the capacity expansion model, it consistently produced higher-cost outcomes. Based on these results, it was not carried forward in subsequent capacity expansion modeling.

3.9.2.1. Data Sources and Modeling Approach

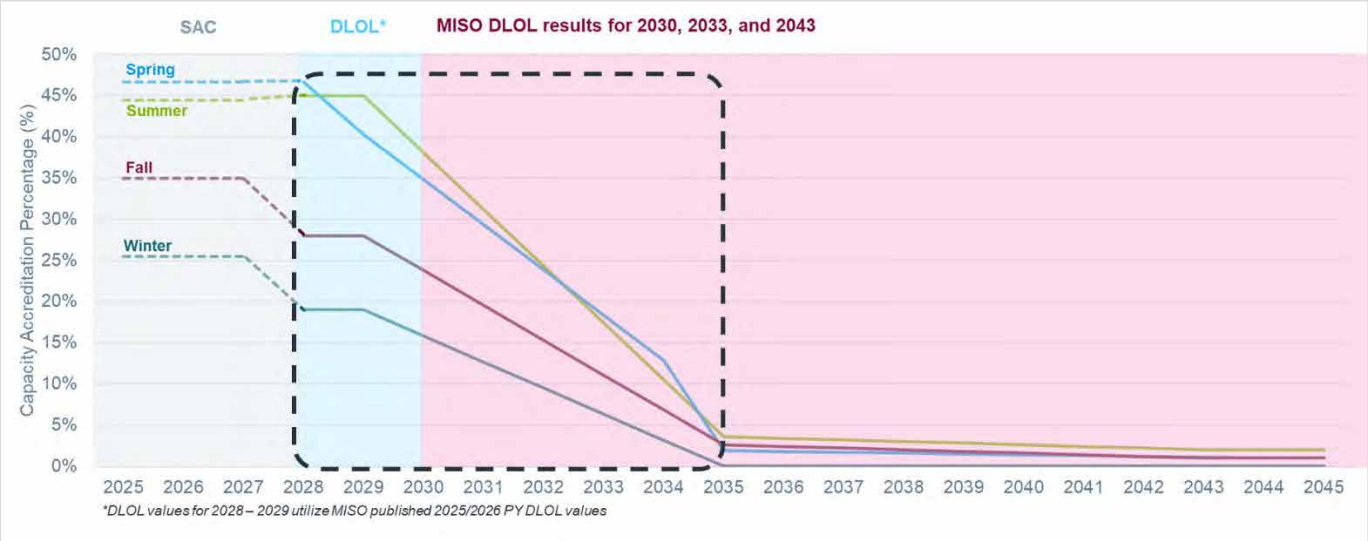
CEI South incorporated MISO's updated DLOL methodology into its 2025 IRP modeling to ensure consistency with the evolving regional framework. The most current publicly available MISO sources were used to obtain capacity accreditation values for each technology type. SAC accreditation percentages for wind and solar were taken from MISO's 2025/2026 Planning Year ("PY") Loss of Load Expectation ("LOLE") Report[33], while accreditation for all other technologies was sourced from MISO's 2023/2024 PY Effective Load Carrying Capability ("ELCC") data[34]. SAC values were applied through Summer 2027, after which DLOL implementation is expected to begin in Summer 2028. MISO's 2025/2026 PY Indicative DLOL Results[35] were used from 2028 through 2030. DLOL values for 2030, 2033, and 2043 were obtained from MISO's Regional Resource Assessment ("RRA") Technical Appendix[36], with interpolation used to determine values for intermediate years, and post-2043 values held constant through 2045.

3.9.2.2. Transition from SAC to DLOL

To ensure a consistent and realistic transition from SAC to DLOL accreditation, CEI South applied a smoothing process to the DLOL values across all resource types. Initial DLOL results from MISO indicated steep accreditation declines during the early implementation years. Following stakeholder feedback regarding this shift, CEI South introduced a moderated adjustment between 2028 and 2035. Figure 3-42 shows the change to the solar capacity accreditation. This smoothing approach preserves the overall downward trend observed in MISO's published data while providing a more stable near-term trajectory for planning and cost modeling purposes.

[33] Planning Year 2025 – 2026 Loss of Load Expectation Study Report. MISO. https://cdn.misoenergy.org/PY%202025-2026%20LOLE%20Study%20Report685316.pdf?v=20250313114401. March 2025. Page 21.
[34] Market Redefinition: Accreditation Reform. MISO. https://cdn.misoenergy.org/20240228%20RASC%20Item%2005a%20Accreditation%20Presentation%20RASC-2020-4%202019-2631885.pdf. February 28, 2024. Page 33.
[35] Planning Year 2025 – 2026 Indicative Direct Loss of Load (DLOL) Results. MISO. https://cdn.misoenergy.org/PY%2025-26%20Indicative%20DLOL%20Results657893.pdf. April 2025. Page 3.
[36] Technical Appendix: 2024 Regional Resource Assessment Assumptions and Methodology. MISO. https://cdn.misoenergy.org/2024%20RRA_Technical%20Appendix676208.pdf. November 2024. Page 11. Accreditation values between 2028 and 2035 were adjusted for the smoothing process; the 2030 values were not utilized, and the 2033 values were incorporated in 2035.

Figure 3-42 – Example of Smoothed Transition from SAC to DLOL for Solar Resources





Portfolio Development and Evaluation

Chapter 4

4.1. Portfolio Development

CEI South developed a wide range of portfolios for scenario modeling in the dispatch module of EnCompass and ultimately for the probabilistic modeling portion of this IRP process. In collaboration with external stakeholders and informed by feedback provided in the IURC Director's Report on the 2022/2023 IRP, CEI South developed 12 portfolios for final evaluation. These included a status quo case, where F.B. Culley 3 continues to run on coal throughout the study period for benchmarking purposes, scenario-based portfolios optimized under varying market conditions, portfolios focused on existing resource decisions, diversified portfolios with a balanced mix of generation technologies, and renewables-focused portfolios incorporating stakeholder input. Each portfolio was designed with the flexibility to include near-term solar, wind, and battery storage resources identified through the All-Source RFP. Mid- and long-term resource options were drawn from both the 2024 All Source RFP and a comprehensive technology assessment performed by 1898 & Co., which provided cost and performance data for technologies not represented in the 2024 All Source RFP. Values trended forward using available NREL cost curves. All portfolios were designed to include energy efficiency and demand response programs. DSM programs were selected for cost-effectiveness during the first stage of deterministic runs; runs that were selected 95% of the time were then included in all portfolios. All near-term programs included in the previously approved 2025-2027 plan were included in the model.

4.1.1. Optimization Runs

4.1.1.1. Deterministic Portfolio Results

Deterministic modeling was conducted to evaluate individual conversion options at existing CEI South generation sites. In each case, the model was directed to include a specific conversion configuration and optimize a portfolio surrounding that decision. This approach allowed CEI South to compare the cost, performance, and operational outcomes of each option under Reference Case conditions, establishing baseline expectations for cost, capacity, and operational performance across all conversion and retirement pathways.

Several consistent trends emerged from these model runs. In more than half of the simulations, the model selected the conversion of the existing A.B. Brown 5 and 6 combustion turbines to a 2x1 Combined Cycle, indicating the capacity and energy need, as well as the high firm capacity value associated with the thermal units. At the F.B. Culley 3 site, the model generally favored retirement of the unit, although this outcome is heavily influenced by the path selected at the A.B. Brown site.

4.1.1.1.1. F.B. Culley 2 Replacement

In anticipation of the suspension of F.B. Culley 2 at the end of 2025, CEI South evaluated four potential replacement options for this unit: installing natural gas aeroderivative or reciprocating engines, building a lithium-ion storage facility, or allowing the interconnection rights to expire. Each option was modeled individually under Reference Case assumptions to assess relative cost and system performance. The results of these model optimization runs are summarized below in Figure 4-1.

The deterministic analysis showed that allowing the interconnection rights to expire resulted in the lowest-cost outcome, within approximately one percent of the cost of constructing a lithium-ion storage facility. Due to the similar portfolio cost of each pathway, the decision for future pathways at F.B. Culley 2 remained unconstrained in subsequent model runs and portfolio development, with the exception of portfolio 12, the delayed reference case.

Figure 4-1 – F.B. Culley 2 Deterministic Model Results

Year	F.B. Culley 2 Aeroderivative	F.B. Culley 2 No Interconnect Re-Use	F.B. Culley 2 Reciprocating Engines	F.B. Culley 2 Storage
2028	+1 FBC2 Aero (86 MW)	1 FBC2 Do Nothing	+1FBC2 Recip Engines (110 MW)	+1 FBC2 Storage (90 MW)
2030	+1 AB Brown7: Fired CCGT 2030 (850 MW)	+1 AB Brown7: Fired CCGT 2030 (850 MW)	+1 AB Brown7: Fired CCGT 2030 (850 MW)	+1 AB Brown7: Fired CCGT 2030 (850 MW)
2031				
2032	-1 FB Culley:3 Retire 2032 (-270 MW) +1 50 MW 4 Hour Storage (50 MW)	-1 FB Culley:3 Retire 2032 (-270 MW)	-1 FB Culley:3 Retire 2032 (-270 MW)	-1 FB Culley:3 Retire 2032 (-270 MW)
2033		+1 100 MW 4 Hour Storage (100 MW)		+1 50 MW 4 Hour Storage (50 MW)
2034				
2035				
2038				
2039				
2040				
2041	+1 Non IRA Solar PV (100 MW)		+1 50 MW 4 Hour Storage (50 MW)	
2042	+1 50 MW 4 Hour Storage (50 MW)	+1 50 MW 4 Hour Storage (50 MW)		
2043				+1 50 MW 4 Hour Storage (50 MW)
2044				
2045	+1 50 MW 4 Hour Storage (50 MW)	+1 50 MW 4 Hour Storage (50 MW)	+1 50 MW 4 Hour Storage (50 MW)	
% Delta to Min NPV	**8.1%**	**0.0%**	**5.3%**	**1.0%**

4.1.1.1.2. Demand Side Management Deterministic Runs

Deterministic model runs conducted for conversion decisions at existing sites, together with the reference case and scenario-based runs, were used to evaluate the selection frequency of Energy Efficiency and Demand Response programs. In total, 15 runs were analyzed to identify which DSM programs were most consistently selected by the model. The Near-term ("NT") programs shown in Figure 4-2, which cover the years 2025 through 2027, were part of the previously approved plan and were included as fixed programs in this analysis. In addition, other programs, such as the Demand Response Aggregator program ("DR

Industrial") approved in Cause No. 45990, were also fixed programs consistent with the approved plan.

Figure 4-2 summarizes how frequently each program was selected across the DSM Deterministic runs. Programs that were selected more than 95% of the time were deemed consistently cost-effective and subsequently treated as a fixed resource in all future portfolio optimizations. The remaining programs were allowed to be selected, but not fixed, in each portfolio.

Figure 4-2 – Demand Side Management Deterministic Results

Program Name	Fixed or Selectable	Selection Frequency	Selection Percent
DR Industrial (DR Aggregation Program)	**Fixed**	**19/19**	**100%**
DR_CI Battery	Selectable	0/19	0%
DR_CI BYOT	**Selectable**	**19/19**	**100%**
DR_CI EV	Selectable	0/19	0%
DR_CI TOU CPP	Selectable	18/19	94%
DR_CI WH Grid	Selectable	9/19	47%
DR_Res AC Switch	**Fixed**	**19/19**	**100%**
DR_Res AC Switch_NT	**Fixed**	**19/19**	**100%**
DR_Res Battery	Selectable	1/19	5%
DR_Res BYOT	Selectable	4/19	21%
DR_Res BYOT_NT	**Fixed**	**19/19**	**100%**
DR_Res EV	Selectable	1/19	5%
DR_Res Smart Cycle	Selectable	1/19	5%
DR_Res Smart Cycle_NT	**Fixed**	**19/19**	**100%**
DR_Res TOU CPP	**Selectable**	**19/19**	**100%**
DR_Res WH Grid	Selectable	1/19	5%
DR_Res WH Switch	**Fixed**	**19/19**	**100%**
DR_Res WH Switch_NT	**Fixed**	**19/19**	**100%**
EE_CI_ERAP_NT, V1, V2, V3	**Selectable**	**19/19**	**100%**
EE_IQ HEAR_NT, V1, V2, V3	**Fixed**	**19/19**	**100%**
EE_IQW_V1, V2, V3	**Fixed**	**19/19**	**100%**
EE_Res_HER_V1, V2, V3	Selectable	0/19	0%
EE_Res_Tier 1_HER_NT, V1, V2, V3	**Selectable**	**19/19**	**100%**
EE_Res_Tier1_V1, V2, V3	Selectable	0/19	0%
EE_Res_Tier2_V1, V2, V3	Selectable	2/19 - 3/19	11-16%

A supplemental sensitivity analysis was also conducted to assess the impact of a shorter program horizon for Demand Response programs. This case evaluated only the first six

years of cost and production, relative to the 18-year study period used in the deterministic runs. No additional DR programs were selected when evaluated based on the first 6 years.

4.1.1.1.3. Distributed Generation Resource Portfolios

CEI South also evaluated a potential distributed generation solar incentive program intended to encourage customers to install behind-the-meter solar resources, thereby reducing system energy requirements. CEI South worked with Itron to update its solar payback model to include a $500 per kW incentive, to increase the adoption rate of behind-the-meter solar. Based on a solar PV adoption forecast developed by Itron, the program was estimated to reduce system load by a cumulative 137 MW (non-coincident) by 2045 and increase the net present value of portfolio revenue requirements by approximately $34.6 million.

When the IRP EnCompass model performed an optimized capacity expansion simulation under Reference Case conditions with this reduced load, the resulting portfolio was nearly identical to the Reference Case. The only difference was a one-year delay in the addition of storage resources, from 2039 to 2040 and from 2042 to 2043. This result indicates that while the incentive program would reduce energy requirements, long-term planning needs remain primarily driven by capacity. Furthermore, cost savings from reduced operational costs to serve the reduced load were insufficient to offset the cost of the incentive program, as the all-in cost of the optimized distributed generation portfolio was approximately $10 million higher than the Reference Case portfolio. Therefore, a distributed generation portfolio was excluded from the risk analysis.

4.1.1.2. Scenario-Based Portfolios

Scenario-Based portfolios (Reference Case, Low Regulatory, High Regulatory, Alternate High Regulatory) were developed to evaluate various regulatory constructs, economic and market conditions, and levels of electricity demand. The scenario-based portfolios move from Low to High Regulatory, with increasing levels of regulation and higher or lower economic drivers. While the Reference Case is considered the most likely future, the alternative scenario-based portfolios were developed to produce and test portfolios in plausible future states that differ from the reference case.

Following stakeholder feedback, the exact model outputs from these scenario optimization runs were used to produce scenario-driven portfolios. Note that these portfolios are developed under varying load conditions (as per the scenario definitions) but are then simulated using the same load inputs as all other portfolios during the risk analysis. These scenario-based portfolios are shown in Figure 4-3.

Figure 4-3 – Scenario Optimization Model Outputs

Year	Optimized Reference Case *(Portfolio 1)*	Optimized Low Reg *(Portfolio 8)*	Optimized High Reg *(Portfolio 9)*	Optimized Alt High Reg *(Portfolio 10)*
2028	1 FBC2 Do Nothing	+1 FBC2 Storage (90 MW)	1 FBC2 Do Nothing	1 FBC2 Do Nothing
2030	+1 AB Brown7: Fired CCGT 2030 (850 MW)	+1 AB Brown7: Fired CCGT 2030 (850 MW)	1 ABB5/6 Continue +3 Non IRA Wind + Storage (600 + 300 MW)	+1 Non IRA Wind (200 MW)
2032	-1 FB Culley:3 Retire 2032 (-270 MW)	-1 FB Culley:3 Retire 2032 (-270 MW)	-1 FB Culley:3 Retire 2032 (-270 MW) +1 Non IRA Wind + Storage (200 + 100 MW)	-1 FB Culley:3 Retire 2032 (-270 MW) +1 Non IRA Solar PV (100 MW) +2 Non IRA Wind + Storage (400 + 200 MW)
2033	+1 100 MW 4 Hour Storage (100 MW)			
2034				+1 AB Brown7: Fired CCGT 2034 (850 MW)
2038		+1 50 MW 4 Hour Storage (50 MW)		
2040	+1 50 MW 4 Hour Storage (50 MW)			
2042		+1 50 MW 4 Hour Storage (50 MW)		
2043	+1 50 MW 4 Hour Storage (50 MW)			
2045		+1 Non IRA Solar PV + Storage (100 + 50 MW)		

4.1.2. Final Portfolios for Risk Analysis

With these early modeling results in mind, additional portfolios and iterations were developed based on 1) stakeholder feedback, 2) lessons learned from preliminary portfolio optimization results, and 3) examining tradeoffs in different existing resource decision timing. Once all twelve of these diverse portfolios were created, they were run through the EnCompass model to be considered in the Risk Analysis portion of this IRP.

Figure 4-4 summarizes the resource buildouts for the portfolios selected for inclusion in the risk analysis[37].

[37] Portfolio 12 (Delayed Reference Case) was updated from the fourth stakeholder meeting held on 10/23/2025. In that meeting, the 50 MW 4-hour storage resource was presented to come online in 2042; the table entry was corrected to 2040. The slide deck on the CenterPoint IRP website (Integrated Resource Plan (IRP)) reflects this update.

Figure 4-4 – Final Risk Analysis Portfolios

Year	Portfolio1_Reference Case Portfolio	Portfolio2_Convert FBC3 to NG by 2035	Portfolio3_FBC3 on Coal without ABB7	Portfolio4_FBC3 on Coal to SMR	Portfolio5_FBC3 to Simple Cycle Gas Turbine	Portfolio6_Renewable Heavy Portfolio
2028	1 FBC2 Do Nothing	1 FBC2 Do Nothing	1 FBC2 Do Nothing	1 FBC2 Do Nothing	1 FBC2 Do Nothing	1 FBC2 Do Nothing
2030	+1 AB Brown7: Fired CCGT 2030 (850 MW)	+1 AB Brown7: Fired CCGT 2030 (850 MW)	1 ABB5/6 Continue	+1 AB Brown7: Fired CCGT 2030 (850 MW)	1 ABB5/6 Continue	1 ABB5/6 Continue
2032	-1 FB Culley:3 Retire 2032 (-270 MW)		+1 100 MW 4 Hour Storage (100 MW)			-1 FB Culley:3 Retire 2032 (-270 MW) +3 100 MW 4 Hour Storage (300 MW)
2033	+1 100 MW 4 Hour Storage (100 MW)		+2 100 MW 4 Hour Storage (200 MW)		+1 100 MW 4 Hour Storage (100 MW)	+2 100 MW 4 Hour Storage (200 MW)
2034						
2035		+1 FB Culley:3 NG 2035 (270 MW)		-1 FB Culley:3 Retire 2035 (-270 MW) +1 Nuclear - SMR (100 MW)	-1 FB Culley:3 Retire 2035 (-270 MW) +1 J Class SCGT (385 MW)	
2038						
2039						
2040	+1 50 MW 4 Hour Storage (50 MW)					
2041					+1 Non IRA Wind + Storage (200 + 100 MW)	+1 Non IRA Wind (200 MW)
2042			+1 50 MW 4 Hour Storage (50 MW)	+1 100 MW 4 Hour Storage (100 MW)		+1 Non IRA Wind + Storage (200 + 100 MW)
2043	+1 50 MW 4 Hour Storage (50 MW)					
2044						
2045			+1 FB Culley:3 thru 2045 (270 MW) +2 Non IRA Solar PV (200 MW) +1 Non IRA Wind (200 MW)		+1 Non IRA Wind (200 MW)	

Year	Portfolio7_FBC3 Gas Conversion with Renewables	Portfolio8_Low Reg Approach	Portfolio9_High Reg Approach	Portfolio10_Alt High Reg Approach	Portfolio11_FBC3 Co-Fire 2030	Portfolio12_Delayed Reference Case
2028	1 FBC2 Do Nothing	+1 FBC2 Storage (90 MW)	1 FBC2 Do Nothing	1 FBC2 Do Nothing	1 FBC2 Do Nothing	+1 FBC2 Storage (90 MW)
2030	+1 FB Culley:3 NG 2030 (270 MW) 1 ABB5/6 Continue	+1 AB Brown7: Fired CCGT 2030 (850 MW)	1 ABB5/6 Continue +3 Non IRA Wind + Storage (600 + 300 MW)	+1 Non IRA Wind (200 MW)	+1 FB Culley:3 Co-Fire 2030 (270 MW) +1 AB Brown7: Fired CCGT 2030 (850 MW)	
2032		-1 FB Culley:3 Retire 2032 (-270 MW)	-1 FB Culley:3 Retire 2032 (-270 MW) +1 Non IRA Wind + Storage (200 + 100 MW)	-1 FB Culley:3 Retire 2032 (-270 MW) +1 Non IRA Solar PV (100 MW) +2 Non IRA Wind + Storage (400 + 200 MW)		
2033	+2 100 MW 4 Hour Storage (200 MW) +1 50 MW 4 Hour Storage (50 MW)					
2034				+1 AB Brown7: Fired CCGT 2034 (850 MW)		+1 AB Brown7: Fired CCGT 2034 (850 MW)
2035						-1 FB Culley:3 Retire 2035 (-270 MW)
2038		+1 50 MW 4 Hour Storage (50 MW)			-1 FB Culley:3 Retire (270 MW)	
2039					+2 50 MW 4 Hour Storage (100 MW)	
2040	+1 Non IRA Wind (200 MW)				+1 50 MW 4 Hour Storage (50 MW)	+1 50 MW 4 Hour Storage (50 MW)
2041						
2042	+1 50 MW 4 Hour Storage (50 MW)	+1 50 MW 4 Hour Storage (50 MW)				
2043						
2044					+1 50 MW 4 Hour Storage (50 MW)	
2045	+1 100 MW 4 Hour Storage (100 MW) +2 Non IRA Wind (400 MW)	+1 Non IRA Solar PV + Storage (100 + 50 MW)				+1 50 MW 4 Hour Storage (50 MW)

Moreover, Figure 4-5 explicitly states the motivation behind the development of these twelve portfolios. The first group includes the portfolios informed by the deterministic optimization results and explores various existing unit decisions. The second group, as mentioned in Section 4.1.1.2, is the scenario-based portfolios. The final group reflects portfolios shaped by stakeholder input. These portfolios include the two portfolios with an increased renewable penetration in CEI South's resources mix as well as a portfolio with a Small Modular Reactor as a potential resource option.

Figure 4-5 – Description of Portfolio Motivations

Portfolio Name	Motivation
2-Convert FB Culley 3 to NG by 2035	Deterministic Portfolios (economically optimized model given fixed existing site decisions and potential replacement options for F.B. Culley 3)
3-Continue FB Culley 3 on Coal through 2045	
5-FB Culley 3 to Simple Cycle Gas Turbine	
11-FB Culley 3 Co-Fire	
12-Delayed Reference Case	
1-Reference Case Portfolio	Scenario-Based Portfolios (economically optimized model for each scenario)
8-Low Regulatory Approach	
9-High Regulatory Approach	
10-Alternate High Regulatory Approach	
4-FB Culley 3 to Small Modular Reactor	Stakeholder Input Portfolios
6-Renewable Heavy	
7-FB Culley 3 Gas Conversion with Renewables	

4.2. Evaluation Of Portfolio Performance

Each of the risk analysis candidate portfolios were subjected to two different forms of risk modeling. One was scenario-based (deterministic), and one was based on probabilistic modeling (200 iterations), which serves as the basis for the balanced scorecard. The inputs into the EnCompass model that were used to generate the following results are given in the *Technical Appendix Attachment 4.1 CEIS 2025 IRP Model with Scenarios & Stochastics Model (Confidential)*.

4.2.1. Scenario Risk Analysis (Simulated Dispatch in Each Scenario)

The IRP requires scenario-based modeling be performed as a part of the risk analysis. In the scenario-based risk analysis, the twelve candidate portfolios selected for further analysis were modeled under each of the four core scenarios with their respective market inputs. The following provides a summary of the results of this scenario-based risk analysis. The results shown in Figure 4-6 and Figure 4-7 are NPVRR and the cumulative carbon-dioxide emissions of each portfolio under each scenario. In the alternative high regulatory and high regulatory scenarios, capacity factor limitations associated with the CAA 111(b) and (d) legislation tend to increase the operating costs of portfolios while also limiting the portfolio emissions. The Preferred Portfolio performs fairly consistently across all four scenarios, avoiding extreme outcomes while allowing time for re-evaluation in a future IRP before the F.B. Culley 3 decision must be finalized.

Figure 4-6 – Portfolio NPVRR (Million $)

Portfolio	Reference Case	Alt High Regulatory	High Regulatory	Low Regulatory
1-Reference Case	$3,455	$4,613	$4,093	$3,458
2-FBC3 NG 2035	$3,430	$4,338	$4,119	$3,338
3-FBC3 on Coal	$3,959	$4,639	$4,435	$4,211
4-FBC3 to SMR	$4,126	$5,164	$4,464	$4,433
5-FBC3 to SCGT	$4,145	$5,009	$4,620	$4,128
6-Renewable Heavy	$4,144	$5,417	$4,315	$4,536
7-FBC3 NG with Renewables	$4,174	$5,336	$4,604	$4,193
8-Low Reg	$3,497	$4,572	$4,047	$3,431
9-High Reg	$4,247	$4,185	$2,970	$4,721
10-Alt High Reg	$3,960	$4,057	$3,294	$4,389
11-FBC3 Co-Fire	$3,556	$4,557	$4,181	$3,485
12-Delayed Reference	$3,625	$4,572	$4,175	$3,572

Figure 4-7 – Portfolio Total CO_2 Emissions Over Study Period (Million Tons)

Portfolio	Reference Case	Alt High Regulatory	High Regulatory	Low Regulatory
1-Reference Case	61	46	39	63
2-FBC3 NG 2035	69	55	46	72
3-FBC3 on Coal	69	78	57	70
4-FBC3 to SMR	66	53	44	66
5-FBC3 to SCGT	51	61	46	58
6-Renewable Heavy	35	44	34	39
7-FBC3 NG with Renewables	42	49	36	50
8-Low Reg	61	46	39	63
9-High Reg	34	43	32	38
10-Alt High Reg	51	44	37	53
11-FBC3 Co-Fire	68	50	43	69
12-Delayed Reference	62	52	43	65

4.2.2. Probabilistic Risk Analysis (Simulated Dispatch 200 Runs Scorecard)

After selecting the twelve portfolios for further consideration and completion of the scenario-based risk assessment, the remaining steps are to conduct the 200 iteration stochastic risk assessment, complete the balanced scorecard, and consider "other" relevant factors to select the Preferred Portfolio.

A comprehensive risk analysis using 200 iterations provides a more thorough understanding of how the different portfolios perform under a range of scenarios. As with any analysis, the risk assessment and subsequent balanced scorecard do not provide CEI South with an answer but instead offer insights into tradeoffs associated with the portfolios across a range of possible future conditions. Among other things, the results of this evaluation help CEI South get a clearer picture of the balance between total portfolio cost, the cost uncertainty (measured by the 5^{th} and 95^{th} percentile of cost outcomes over the planning horizon), the carbon equivalent profile, the percentage dependence on energy and capacity purchases and sales, and the stability, reliability, and resilience of the portfolios based on the probabilistic range of potential outcomes.

A color-coded comparison (shaded automatically by the Microsoft Excel spreadsheet) of the balanced scorecard is shown below in Figure 4-8[38]. The color coding represents the relative ranking among the portfolios. Green generally indicates scoring well relative to other portfolios within the same metric, and red generally indicates scoring poorly relative to other portfolios within the same metric. The color scheme is purely for illustrative purposes to show where differences between the best-performing portfolio and the worst-performing portfolio for that metric. Since the color coding is purely relative to the other portfolios, red does not necessarily mean that a portfolio performed poorly on that metric, but relatively worse than other portfolios. For more information on this analysis, please see the final stakeholder presentation in *Technical Appendix Attachment 4.2 Stakeholder Materials*.

[38] The Capacity Purchases NPV ($M) shown in the scorecard and presented during the fourth stakeholder meeting held on 10/23/2025 have been updated and posted to the CenterPoint IRP website.

Figure 4-8 – IRP Portfolio Balanced Scorecard Color-Coded Comparison

Objective	Affordability					Environmental Sustainability				Reliability/Resiliency/Stability					Risk/Other			
Portfolio Description	20 Year NPVRR ($M)	Delta From Reference (%)	5% Value of NPVRR ($M)	95% Value of NPVRR ($M)	Incremental Energy Burden (%) 2030 - 2035	CO_2 Intensity (Tons CO_2e/MWh)	CO_2 Equivalent Emissions (Stack Emissions) (1000s Tons CO_2e)	SOx Emissions (Tons)	NOx Emissions (Tons)	Unserved Energy (MWh)	Spinning Reserve (MW)	Fast Start Capability (MW)	Transmission Reliability Analysis MVAR	Transmission Reliability Analysis SCR	Energy Market Sales (%)	Energy Market Purchases (%)	Capacity Sales NPV ($M)	Capacity Purchases NPV ($M)
2-FBC3 NG 2035	$3,718	0%	$2,941	$4,464	0.13% - 0.22%	0.368	48,696	18,017	13,091	119	1,031	253	753	3.5	26%	9%	$217	$6
1-Reference Case	$3,726	0%	$2,963	$4,439	0.11% - 0.25%	0.346	44,302	12,877	10,650	61	842	340	665	3.5	26%	10%	$140	$14
8-Low Reg	$3,764	1%	$2,983	$4,475	0.15% - 0.20%	0.345	44,199	12,908	10,582	49	842	366	665	3.5	26%	10%	$167	$6
12-Delayed Reference	$3,836	3%	$3,195	$4,467	0.16% - 0.26%	0.391	46,535	21,885	14,539	56	701	444	665	3.5	23%	12%	$115	$18
11-FBC3 Co-Fire	$3,854	3%	$3,064	$4,587	0.18% - 0.17%	0.354	46,317	14,397	11,812	61	937	308	753	3.5	26%	10%	$192	$12
3-FBC3 on Coal	$4,034	8%	$3,511	$4,630	0.03% - 0.29%	0.522	53,636	51,793	25,931	43	302	835	626	3.5	15%	19%	$117	$22
10-Alt High Reg	$4,211	13%	$3,444	$4,829	0.17% - 0.48%	0.280	34,415	14,226	10,985	29	660	486	665	3.5	25%	9%	$159	$19
9-High Reg	$4,297	15%	$3,543	$4,926	0.43% - 0.44%	0.234	25,913	13,701	12,322	15	113	935	605	3.5	20%	14%	$128	$23
5-FBC3 to SCGT	$4,306	16%	$3,857	$4,770	0.14% - 0.59%	0.408	41,016	22,763	16,698	73	154	955	665	3.5	14%	21%	$93	$26
6-Renewable Heavy	$4,309	16%	$3,756	$4,723	0.10% - 0.62%	0.329	28,966	14,385	14,597	38	113	985	605	3.5	11%	30%	$95	$22
7-FBC3 NG with Renewables	$4,375	17%	$3,912	$4,771	0.26% - 0.49%	0.357	34,642	8,289	18,780	76	302	802	626	3.5	14%	23%	$106	$24
4-FBC3 to SMR	$4,456	20%	$3,674	$5,185	0.15% - 0.76%	0.342	45,224	18,653	11,950	52	938	273	665	3.5	26%	9%	$171	$13

1: Average net present value of portfolio revenue requirements from 2026 to 2045
2: Percent difference between average NPVRR of portfolio and reference
3-4: Fifth and ninety-fifth percentiles of net present value of NPVRR to show cost uncertainty
5: Increase in residential bill impact since 2026 as a percentage of median Vanderburg county resident forecasted annual income in 2030 and 2035
6: Quotient of average CO_2e from generation and average fleet generation from 2026 to 2045
7-9: Total CO_2 equivalent, SO_x, and NO_x emissions from 2026-2045
10: Total emergency unserved energy purchased from 2026 to 2045
11: Capacity from “spinning” thermal assets that can be ramped up or down (combined cycle, coal, nuclear)
12: Capacity from “fast start” assets that can be dispatched quickly (combustion turbine, battery)
13-14: Dynamic VAR support and short circuit ratio from transmission reliability analysis
15: Total energy sales as a percentage of total energy generation from 2026 to 2045
16: Total energy purchases as a percentage of total load from 2026 to 2045
17-18: Net present value of capacity sales and purchases from 2026 to 2045

4.3. Results By Portfolio

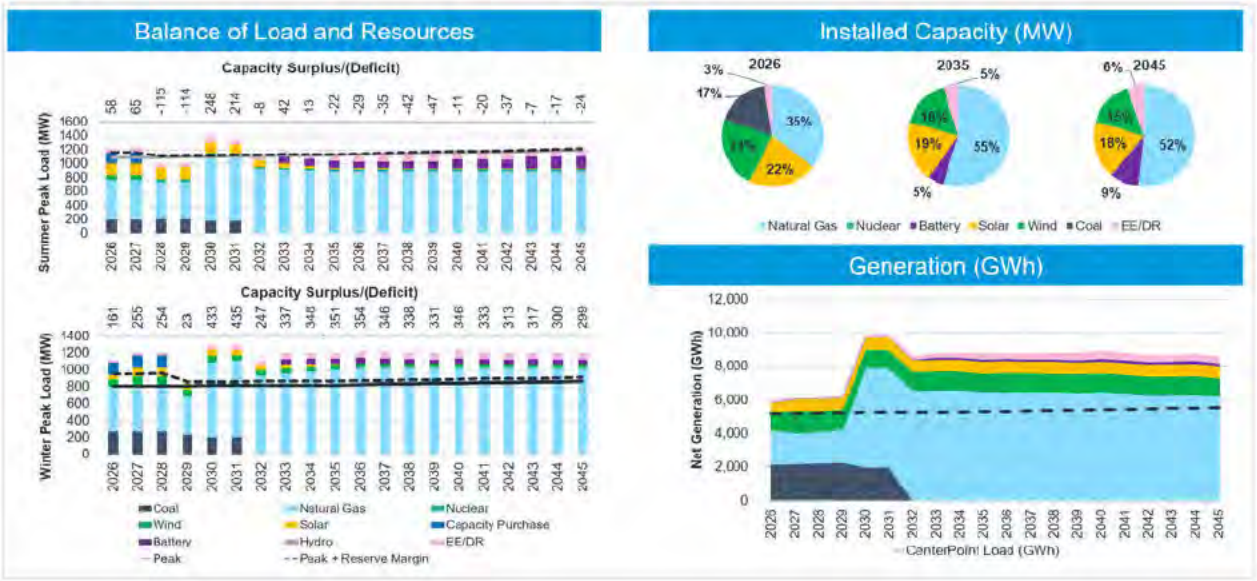
4.3.1. Reference Case Portfolio

The Reference Case portfolio represents the capacity expansion results from the Reference Case scenario. While this portfolio is the least cost in the capacity expansion (reference case) run, the portfolio becomes the second-lowest cost during the Risk Analysis (200 runs) portion of the analysis, as previously seen in Section 4.2.2. This portfolio allows for the expiration of interconnect rights at F.B. Culley 2 ("FBC2 Do Nothing"), conversion of the A.B. Brown 5 and 6 combustion turbines into a 2x1 Duct-Fired Combined Cycle ("A.B. Brown 7"), and retires CEI South's last remaining coal unit that it operates, F.B. Culley 3, at the end of 2031. In addition, the model builds a cumulative 200 MW of 4-hour battery energy storage resources beginning in 2033 through the end of the study period. The selection of batteries in the model is indicative of the need for long-term capacity on CEI South's system, especially following the implementation of MISO's DLOL methodology, which reduces the accreditation of intermittent resources.

The retirement of F.B. Culley 3 and the conversion of A.B. Brown 5 and 6 result in a highly efficient and relatively environmentally friendly portfolio, achieving among the lowest NO_x emissions compared to other portfolios. However, the early investment in A.B. Brown's conversion also necessitates a near-term rate increase, and the trend of increased demand for HRSGs and turbines creates a near-term price risk. The early A.B. Brown conversion and loss of the F.B. Culley 2 and F.B. Culley 3 interconnections also make the portfolio relatively inflexible, as it is less adaptable to changes in regulations, market conditions, and fuel costs.

The results dashboard for the reference case, shown in Figure 4-9, displays the Balance of Load and Resources on the left-hand side. This figure shows the need for capacity in the near-term, which makes the A.B. Brown conversion favorable, as it adds about 400 MW of firm capacity to the system. The installed capacity pie charts on the top right of the figure display the diverse mix of renewable, thermal, and demand-side resources included in the reference case. For all portfolio dashboards, the 32 MW of coal generation from Kyger Creek Generating Station, owned by the Ohio Valley Electric Corporation ("OVEC") and purchased by CenterPoint, is assumed to convert to natural gas in 2030. Finally, in the bottom left, it is observed that for the two years that A.B. Brown 7 and F.B. Culley 3 are online, CEI South's system produces significant excess energy, which it can sell to the MISO market and lower portfolio costs, ultimately benefiting CenterPoint customers but also introduces revenue risk if market conditions change.

Figure 4-9 - Reference Case Portfolio Results Dashboard



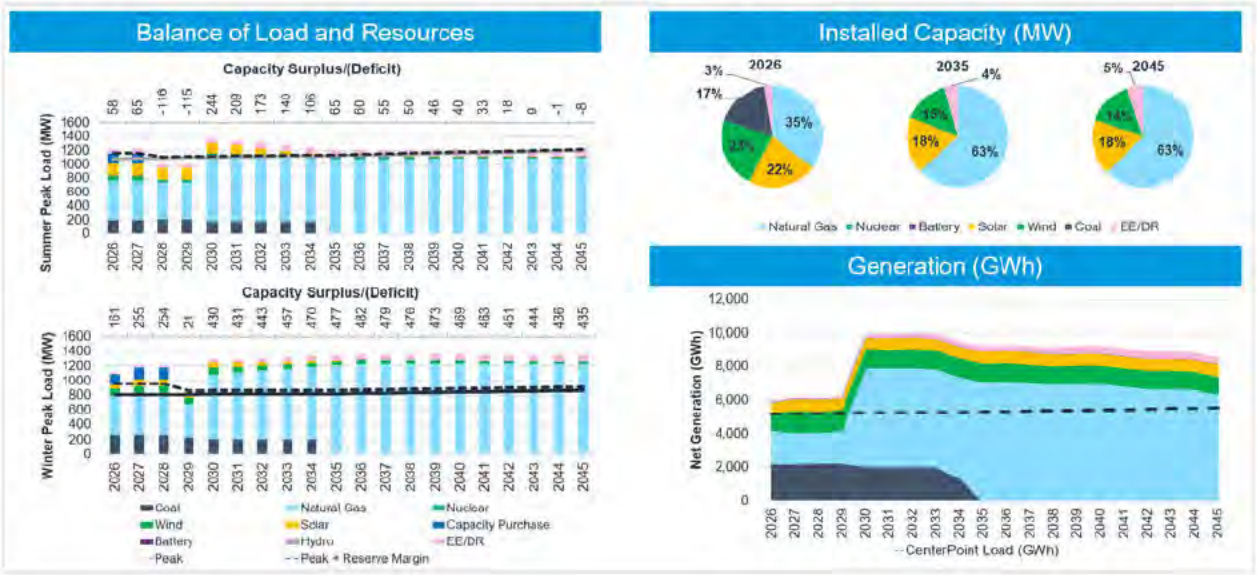
4.3.2. Convert F.B. Culley 3 to Natural Gas by 2035

This portfolio was designed to include the conversion of F.B. Culley 3 from a baseload coal-fired plant to a natural gas peaking plant beginning in 2035 and continuing through the end of the study period. This conversion preserves and repurposes much of the existing site infrastructure while maintaining valuable firm capacity on CEI South's system and lowering CO_2 emission rates. While the model was optimized around the conversion of F.B. Culley 3 to natural gas and the conversion of A.B. Brown 5 and 6 to A.B. Brown 7, no additional resources were necessary to meet all energy and capacity needs.

As seen in Figure 4-10, the inclusion of F.B. Culley 3 and A.B. Brown 7 results in CEI South being long on both capacity and energy, which can be sold to the MISO market to reduce the NPVRR and provide opportunities for economic development. While this portfolio has the lowest NPVRR across 200 draws of varying market conditions, it also relies on the highest levels of both energy and capacity sales, creating a revenue risk if market conditions differ. Moreover, the conversion of A.B. Brown in 2030 necessitates a potential near-term rate increase and introduces price risk from the increased demand for HRSGs and turbines, which could challenge the overall affordability of this portfolio. With natural gas resources comprising over 60% of total installed capacity, this portfolio is sensitive to changing regulations and volatility in fuel costs. Moreover, during the Risk Analysis, this portfolio showed the greatest amount of unserved energy along with the lowest amount of

fast start resources, suggesting potential challenges for the reliability and resiliency of the system, absent potential mitigations.

Figure 4-10 – Convert F.B. Culley to Natural Gas by 2035 Results Dashboard



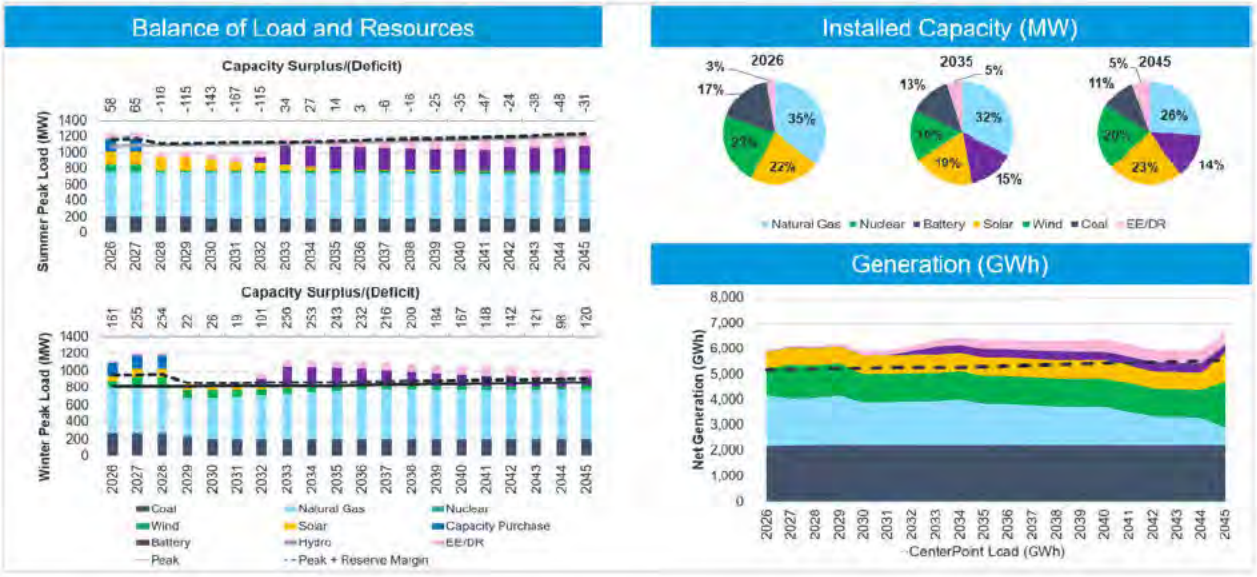
4.3.3. Continue F.B. Culley 3 on Coal through 2045

The F.B. Culley 3 on Coal portfolio serves as a Business As Usual ("BAU") case as it assumes no conversion of existing units and allows for the expiration of the interconnection rights at F.B. Culley 2. Without the conversion of the existing A.B. Brown units, the model chooses to build a cumulative 350 MW of storage facilities to maintain resource adequacy requirements. Moreover, in the final year of the planning horizon, additional solar and wind units are built to address energy needs. As shown in Figure 4-11 this portfolio relies on a significant amount of near-term capacity purchases until the additional storage resources are built.

The continuation of F.B. Culley 3 and the A.B. Brown CTs through the rest of the study period minimizes the need for near-term capital investment, which provides relative rate stability. To conform with environmental regulations included in the reference case, running F.B. Culley 3 on coal throughout the entire study period would require costly efficiency upgrades. Since this portfolio is unique in running F.B. Culley 3 on coal through 2045, the upgrades raise the base year (2026) revenue requirement, making the 2030 incremental energy burden appear lower than other portfolios in the near to midterm. Overall, this portfolio has a moderate NPVRR, approximately 8% greater than the least cost portfolio. As shown in the installed capacity graphs below, this portfolio is well diversified and

therefore less susceptible to cost risk from fuel prices. However, the reliance on inefficient coal generation makes this portfolio environmentally unsustainable, with the highest emissions rates for all considered environmental scoring metrics. These high emissions present a regulatory risk if state and federal objectives change to focus on emissions reduction.

Figure 4-11 – F.B. Culley 3 on Coal through 2045 Results Dashboard



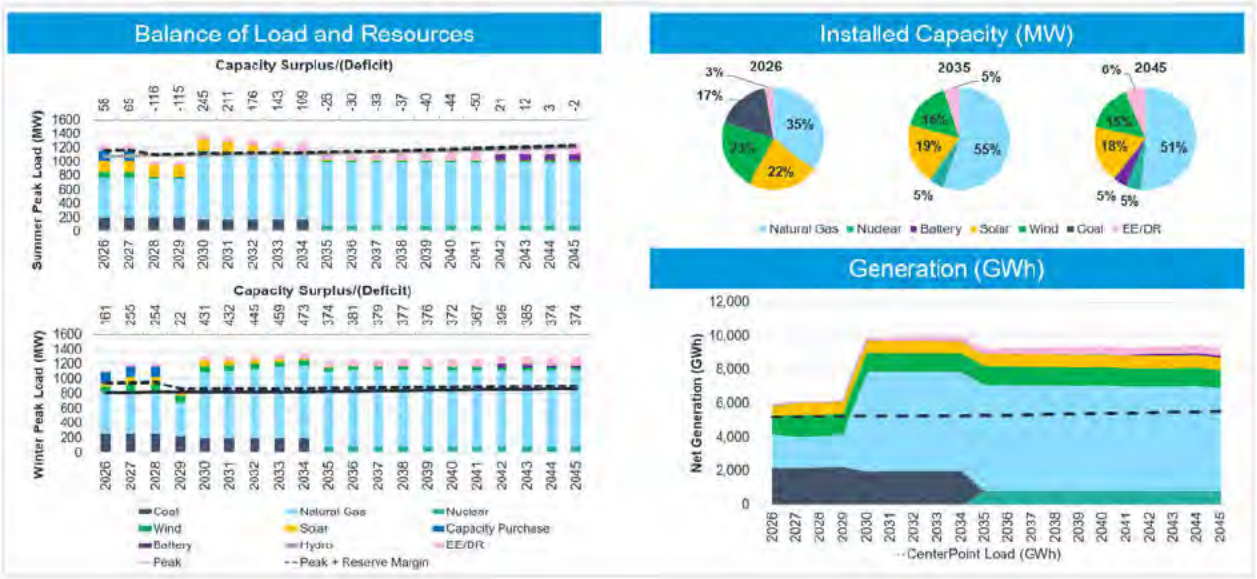
4.3.4. F.B. Culley 3 on Coal to Small Modular Reactor ("SMR")

Including an advanced nuclear portfolio allows CEI South to evaluate a long-term, zero-carbon firm resource that could support reliability as conventional coal resources continue to retire. Therefore, this portfolio retires F.B. Culley 3 at the end of 2034, while assuming that a small modular reactor ("SMR") would be brought online at the beginning of 2035. As shown in Figure 4-12, this portfolio is long on capacity from 2030 through 2034 as both F.B. Culley 3 and the A.B. Brown 7 are online.

This portfolio aligns with state and federal desire for nuclear energy, but the SMRs are also a new and unproven technology, which introduces significant long-term cost risk. The conversion of A.B. Brown 5 and 6 to a CCGT in 2030 would increase costs, making a rate increase necessary in the near-term. Moreover, the inclusion of the SMR in 2035 with CEI South as an off taker makes this portfolio the highest cost portfolio, approximately 20% higher than the least cost portfolio. The temporary capacity surplus from 2030 to 2034 allows the opportunity for significant capacity and energy sales, helping offset a portion of the cost of this advanced nuclear technology. This portfolio is among the highest ranking

in terms of capacity and energy sales, thus representing a significant cost risk with potential for the NPVRR to increase even further if revenues do not materialize.

Figure 4-12 – F.B. Culley 3 on Coal to Small Modular Reactor Results Dashboard



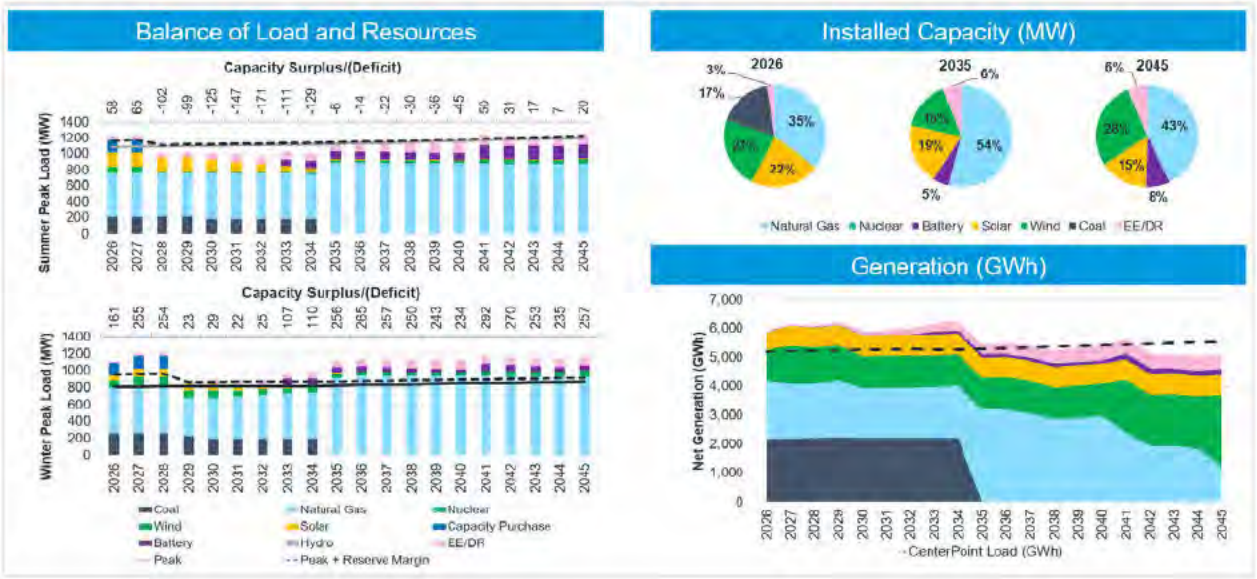
4.3.5. F.B. Culley 3 to Simple Cycle Gas Turbine

This fifth portfolio examines the replacement of CEI South's final coal-fired generating unit that it operates, F.B. Culley 3, with a new 385 MW SCGT. The retirement of F.B. Culley 3 at the end of 2034 is intentionally aligned with the in-service date of the new gas unit, which would begin operation in early 2035. In the absence of converting A.B. Brown 5 and 6 to a combined-cycle configuration (A.B. Brown 7), the portfolio experiences a temporary capacity shortfall that is addressed through the addition of a 100 MW battery storage resource in 2033. Additional wind and battery resources are introduced in the later years of the study to meet growing energy and capacity requirements. Figure 4-13 summarizes the simulated results for this portfolio under Reference Case conditions.

This portfolio maintains flexibility by keeping A.B. Brown 5 and 6 units as combustion turbines and deferring the replacement of F.B. Culley 3 to the beginning of 2035. This reduces risk from changes in regulations and market conditions, reduces the need for near-term investment, and keeps the near-term incremental energy burden low. The addition of storage and wind resources to meet capacity and energy needs over time allows for increased renewable reliance but also increases cost in the long-term, leading to a 20-year NPVRR that is 16% greater than the least-cost portfolio. Because the portfolio is highly reliant on gas combustion turbines, it faces risk associated with gas cost, capacity,

availability of gas, and pipeline regulations that could potentially increase the portfolio's already high long-term cost.

Figure 4-13 – F.B. Culley 3 to Simple Cycle Gas Turbine Results Dashboard



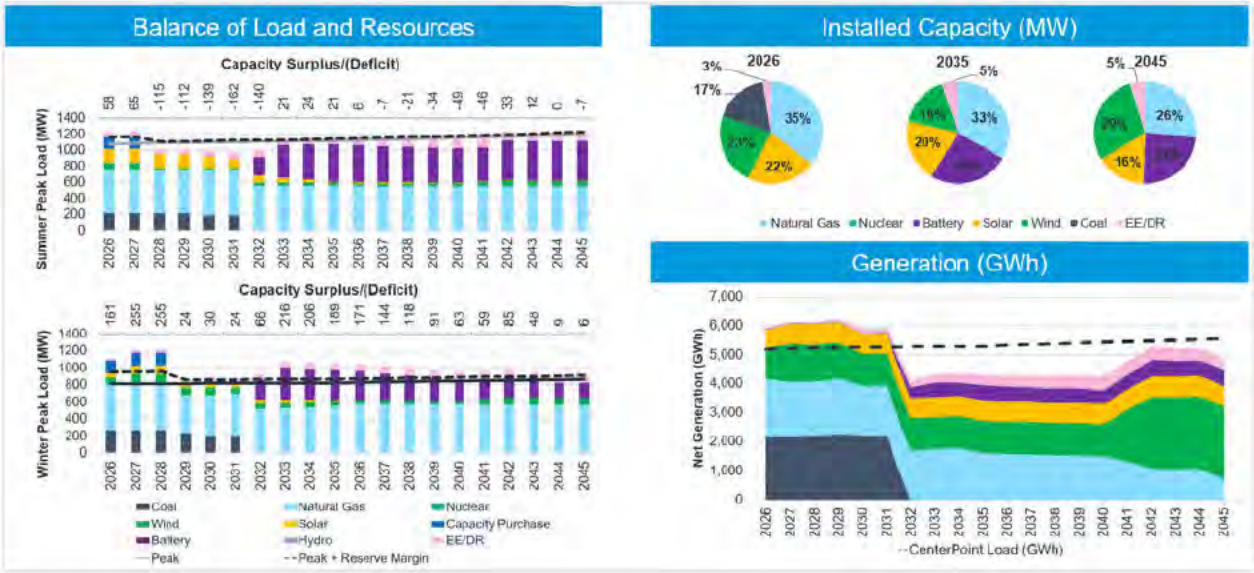
4.3.6. Renewable Heavy Portfolio

This portfolio examines a pathway in which CEI South meets its long-term capacity and energy needs primarily through renewable and storage resources while still maintaining existing thermal gas units. In this portfolio, F.B. Culley 3 retires at the end of 2031, and the model immediately replaces that capacity with 300 MW of 4-hour storage resources in 2032. As the study period continues, the model adds additional storage and wind resources for a cumulative total of 600 MW of storage capacity and 400 MW of wind capacity. The balance of load and resources shown in Figure 4-14 illustrates that this portfolio is generally short on capacity during the summer despite substantial renewable additions. This reflects the declining capacity accreditation of intermittent technologies, which is accelerated under MISO's Direct-Loss-of-Load methodology. The figure also shows that the portfolio is reliant on energy purchases from the retirement of F.B. Culley 3 at the end of 2031 until the end of the planning horizon.

While the rate impact of this portfolio is limited until 2032 due to minimal capital investments and the inclusion of tax incentives before IRA sunset, the long-term cost and cost risk in this portfolio are high. The portfolio is heavily reliant on market capacity purchases in the near-term and energy market purchases in the long-term, a major risk associated with this portfolio. Future uncertainty around MISO's accreditation could result in even greater

capacity deficits. The portfolio is relatively environmentally friendly with low CO_2 emissions, but that comes with execution risk from procuring the amounts of storage and wind needed for this portfolio to function. The loss of interconnections at F.B. Culley 2 and F.B. Culley 3 also make this portfolio inflexible and less able to adapt to regulatory and market conditions.

Figure 4-14 – Renewable Heavy Portfolio Results Dashboard



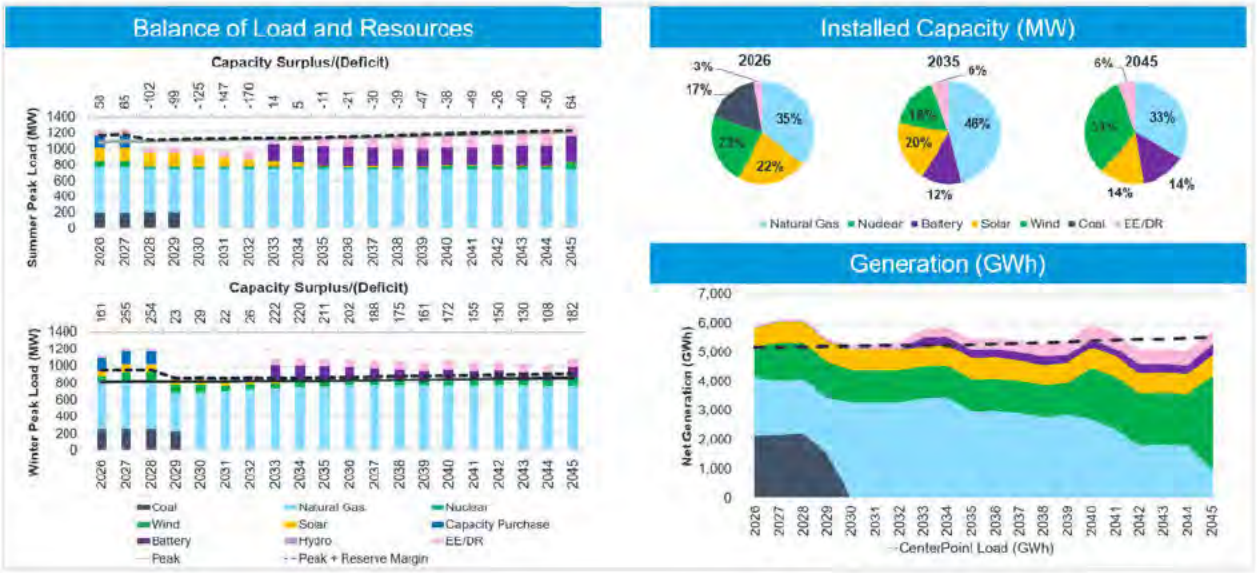
4.3.7. F.B. Culley 3 Gas Conversion with Renewables

This portfolio evaluates the conversion of F.B. Culley 3 from a coal resource to a natural gas-fired unit at the beginning of 2030. This portfolio does not utilize the interconnect at F.B. Culley 2 and does not convert the A.B. Brown 5 and 6 combustion turbines to A.B. Brown 7. Without additional capacity at those existing sites, this portfolio adds firm capacity to the portfolio through additional storage resources in 2033. Similar to previous portfolios, additional wind and storage resources are built in the later years of the study period to meet future energy and capacity needs. As shown in Figure 4-15, as the new resources continue to come online, the generation from F.B. Culley 3 generally declines.

This portfolio has moderate overall emissions released, with the lowest SO_x emissions but the second highest NO_x emissions. Despite the high NO_x emissions, the portfolio is generally well positioned in case environmental regulations change because of its renewable emphasis and the early conversion of F.B. Culley 3. However, the portfolio is among the highest cost portfolios with a high incremental energy burden in both the near and long-term. Additionally, for most years of the planning horizon, this portfolio falls short

on accredited capacity, which exposes CEI South to capacity market price swings and represents a risk as renewable accreditation continues to change.

Figure 4-15 – F.B. Culley 3 Gas Conversion with Renewables Results Dashboard



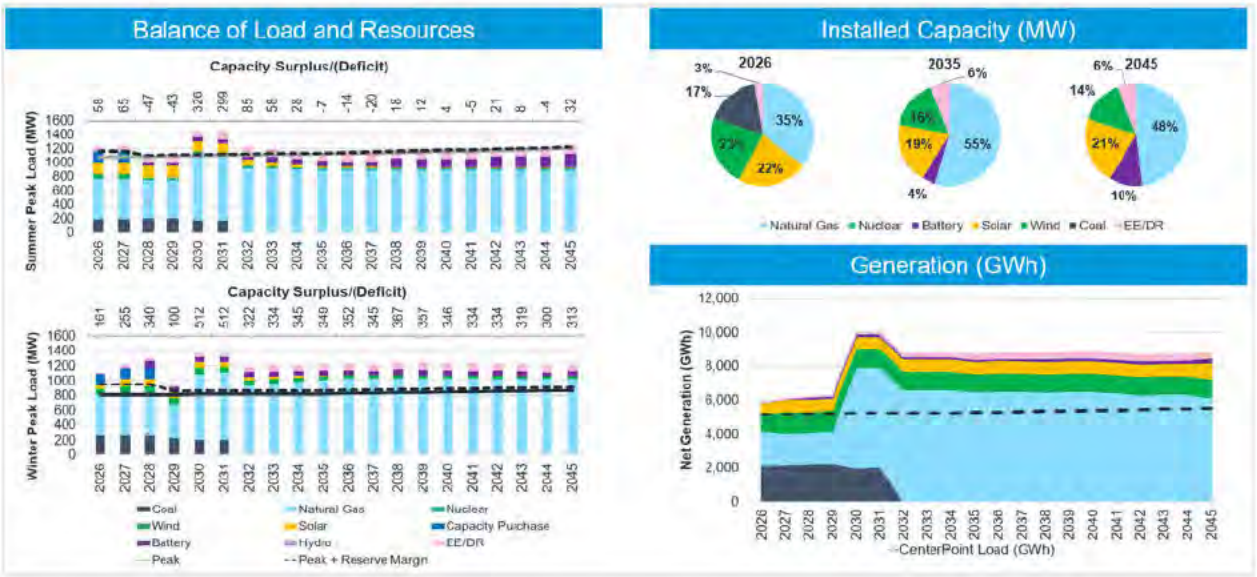
4.3.8. Low Regulatory Portfolio

As mentioned previously, there are three scenario-driven portfolios that are the optimized model results from running the various scenarios. This portfolio represents the optimized outcome under the Low Regulatory scenario, which assumes higher load growth and lower capital costs relative to the Reference Case, driven by reduced regulatory pressure and stronger economic forecasts. Under this scenario, natural gas prices grow modestly while capital cost curves for new construction remain comparatively low.

This portfolio reuses the interconnection at F.B. Culley 2 for a 90 MW battery storage project, which comes online at the beginning of 2028. This portfolio also selects to convert the A.B. Brown 5 and 6 to A.B. Brown 7 in 2030 while retiring F.B. Culley 3 at the end of 2031. Similar to the reference case, additional storage resources are added to the system in 2038 and 2042, indicating the need for long-term capacity on CEI South's system. Finally, in the last year of the study, the model selects a hybrid solar plus storage resource to address the accelerated load growth in this scenario. Pairing the solar resource with storage allows for additional solar produced during the midday hours to be stored and used during peak times. Figure 4-16 displays the results of how the low regulatory portfolio performs under reference case assumptions.

Because it relies heavily on a highly efficient combined cycle gas turbine ("CCGT") at A.B. Brown and reuses the F.B. Culley 2 interconnection for storage, portfolio 8 is relatively inexpensive. Although its NPVRR is only 1% greater than the lowest NPVRR portfolio, the early conversion of A.B. Brown does necessitate a near-term rate increase. The portfolio has among the highest energy sales, which introduces a risk that NPVRR could increase if MISO energy market conditions change. This portfolio has moderate overall emissions, though it has the lowest NO_x emissions rate.

Figure 4-16 – Low Regulatory Portfolio Results Dashboard



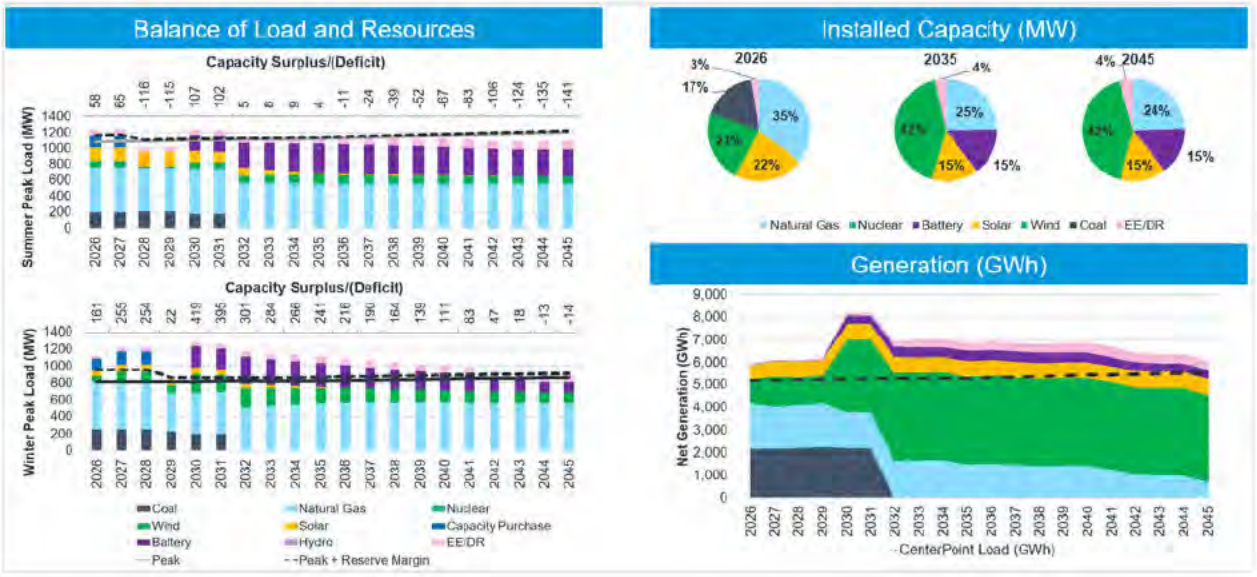
4.3.9. High Regulatory Portfolio

In the High Regulatory scenario, load is assumed to grow at a reduced rate compared to the Reference Case. It has increased fuel prices and lower capital costs for generation resources. Additionally, this scenario includes environmental regulation based on the Clean Air Act (CAA) 111(b) for new gas resources and includes its expansion to existing gas resources, limiting all new and existing gas resources to a 40% annual maximum capacity factor. Moreover, the inclusion of the CAA 111(d) restricts the options for F.B. Culley 3 to either co-fire or convert to natural gas by 2030 or retire by 2032. During the optimization under this scenario, the model selected to retire F.B. Culley 3 at the end of 2031 and continue operating A.B. Brown 5 and 6 without a conversion. The model chooses to fill the capacity and energy gap entirely through hybrid wind and storage resources, for a cumulative total of 800 MW of wind and 400 MW of storage by 2032. Figure 4-17 shows the performance of the high regulatory portfolio under reference case assumptions. Note that since this portfolio is developed to meet a lower load growth, when it is simulated with

Reference Case assumptions, it has a significant shortfall on capacity in the later years of the study.

The High Regulatory portfolio is environmentally friendly with the lowest CO_2e emissions rate and CO_2e intensity. It is well positioned in case environmental regulations change with minimal fuel cost and regulatory compliance risk because of its strong renewable emphasis and F.B. Culley 3 retirement. With 400 MW of storage resources, this portfolio high relatively high fast start capabilities. However, this portfolio is expensive across all affordability metrics, with a high near- and long-term incremental energy burden and NPVRR. Moreover, the inclusion of such large additions (800 MW of wind and 400 MW of storage) across two years brings a significant execution risk, capacity accreditation risk, and likely congestion risk.

Figure 4-17 – High Regulatory Portfolio Results Dashboard



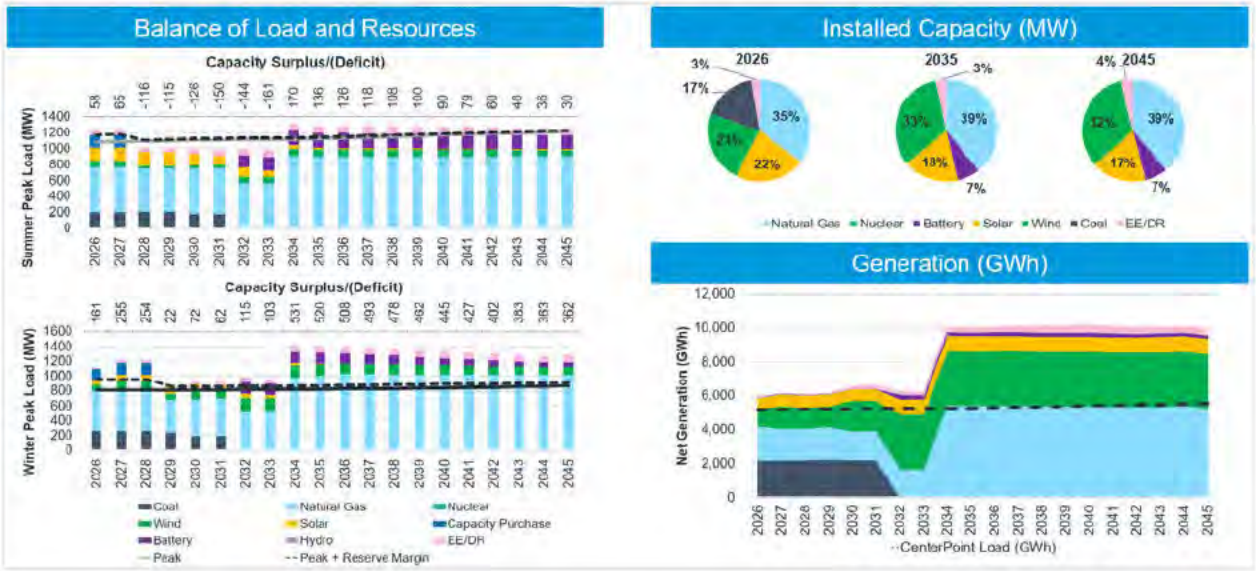
4.3.10. Alternate High Regulatory Portfolio

This portfolio reflects the optimized outcome under the Alternate High Regulatory scenario, which assumes the highest load growth among the scenarios, combined with elevated fuel prices and new resource capital costs. In this portfolio, the interconnection rights expire at F.B. Culley 2 and F.B. Culley 3 retires by 2032 without replacement. The A.B. Brown 5 and 6 combustion turbines are selected to convert to A.B. Brown 7 at the beginning of 2034. To meet long-term energy and capacity needs, the model also selects additional renewable resources, specifically, 600 MW of wind, 200 MW of storage, and 100 MW of solar. As shown in the Balance of Load and Resources chart given in Figure 4-18, the portfolio is

long on capacity when simulated under Reference Case assumptions, reflecting the lower load forecast relative to the Alternate High Regulatory scenario.

The Alternate High Regulatory portfolio is moderately high in cost in both near-term energy burden and 20-year NPVRR. It has the third lowest total CO_2e emissions and second lowest CO_2e intensity because of the renewable emphasis and efficiency of the CCGT at A.B. Brown, minimizing environmental regulatory risk. The need for renewables and storage in the near-term does present execution risk, and the portfolio is generally reliant on capacity purchases until the A.B. Brown conversion takes place in 2034.

Figure 4-18 – Alternate High Regulatory Results Dashboard



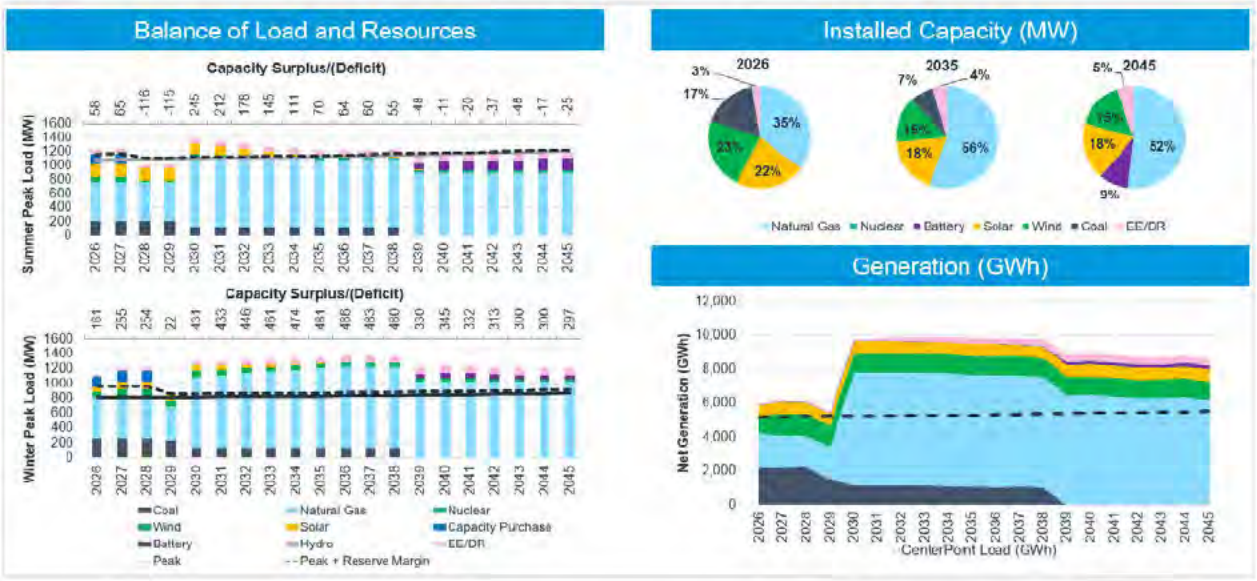
4.3.11. F.B. Culley 3 Co-Fire Portfolio

This portfolio, largely inspired by the regulatory requirements with the Clean Air Act 111, investigates retrofitting F.B. Culley 3 to co-fire with 40% natural gas and 60% coal, until its retirement at the end of 2038. A.B. Brown 5 and 6 convert to A.B. Brown 7 in 2030, which adds additional dispatchability and firm capacity to the portfolio. As illustrated in Figure 4-19, there is excess capacity on the system during the 8 year period in which F.B. Culley 3 is online with A.B. Brown 7. Following the retirement of F.B. Culley 3, the model fills the capacity need with storage resources.

This portfolio is relatively inexpensive as its NPVRR is within 3% of the least-cost portfolio. It is the only portfolio where the incremental energy burden decreases from 2030 to 2035,

so while it has a moderate energy burden in 2030, it has the lowest energy burden by 2035. Despite the low overall costs, the two conversion projects are susceptible to execution risk as well as near-term rate increases due to the large capital investments. While the portfolio is consistent with current state and federal near-term objectives to maintain coal, the continuation of F.B. Culley 3 on coal renders this portfolio exposed to future regulatory risk. Additionally, there are operational risks associated with blending fuels.

Figure 4-19 – F.B. Culley 3 Co-Fire Portfolio Results Dashboard



4.3.12. Delayed Reference Case Portfolio

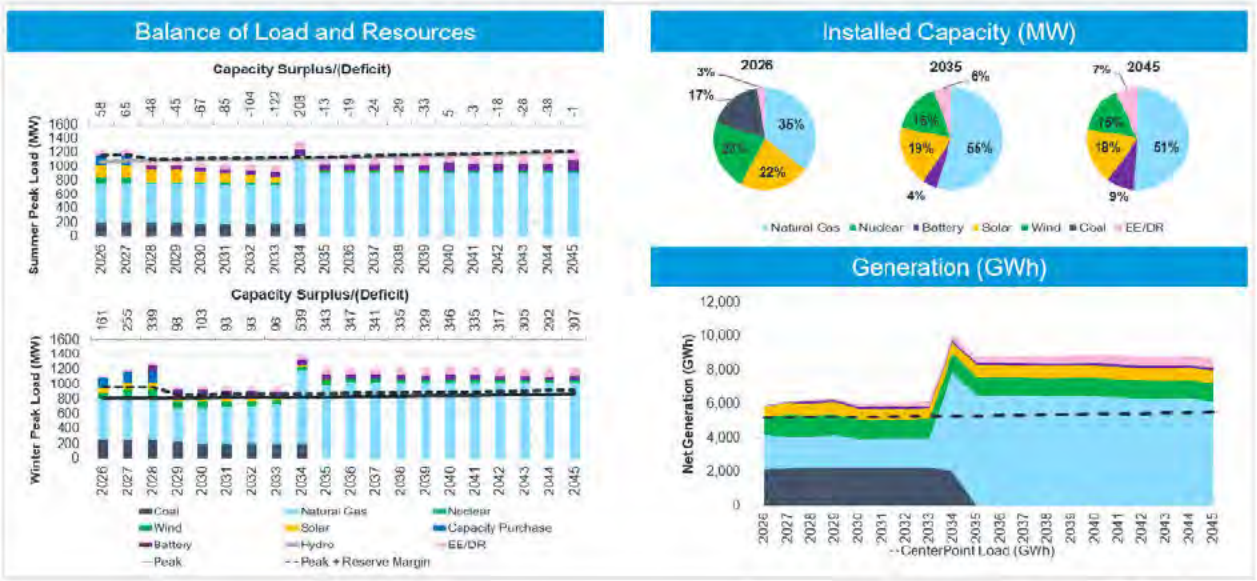
This final portfolio reflects a similar resource plan to the reference case but with delayed timing for major resource decisions to be determined in a future IRP, particularly A.B. Brown 7 which begins operations in early 2034 and F.B. Culley 3 that retires at the end of that same year. By aligning the A.B. Brown 7 conversion date to occur within the same year as the retirement of F.B. Culley 3, the delayed conversion minimizes near-term capital spending and results in less overbuild than the reference case, as illustrated in the Balance of Load and Resources in Figure 4-20.

Additionally, installing a 90 MW battery energy storage resource at F.B. Culley 2 in 2028 leverages existing site infrastructure and interconnection, avoiding future cost risk, while deferring the need for additional capital expenditures for capacity resources until 2040, seven years after the Reference Case begins investing in additional storage. The inclusion of the 4-hour battery at F.B. Culley 2 was tested through a sensitivity analysis, which found that storage resources are more cost-effective than gas options at the site. Furthermore,

pursuing a battery at F.B. Culley 2 or a generic storage resource later in the study period resulted in less than a 0.1% difference in total portfolio costs. As such, the F.B. Culley 2 battery project is included in this portfolio.

The delayed reference case is relatively inexpensive with an NPVRR within 3% of the reference case. It has a moderately low incremental energy burden in the near-term and a moderate CO_2e emissions rate. The delay of the conversion for A.B. Brown and retirement of F.B. Culley 3 makes this portfolio highly flexible, awarding additional time to reassess and adapt to changing regulatory, economic, and market landscape.

Figure 4-20 – Delayed Reference Case Portfolio Results Dashboard





The Preferred Portfolio

Chapter 5

5.1. Preferred Portfolio Recommendation

Based upon several factors, CEI South's Preferred Portfolio is the Delayed Reference Case.

5.1.1. Description of the Preferred Portfolio

The Preferred Portfolio includes a combination of new and existing supply- and demand-side resources designed to balance affordability, reliability, and environmental performance. Supply-side additions include a 90 MW battery at F.B. Culley 2 by 2028, conversion of A.B. Brown 5 and 6 (850 MW) in 2034, and retirement of F.B. Culley 3 (270 MW) by 2035, along with an additional 100 MW of storage between 2040 and 2045. These supply-side resources are complemented by demand-side resources: demand response and energy efficiency. These demand-side resources include seven near-term programs (2026–2027) from the approved plan, along with twenty additional programs across the commercial, residential, and income-qualified sectors over the remainder of the planning horizon. Collectively, these programs account for 46 MW of capacity in the first year of the study period and increase steadily to 156 MW by 2045.

The Preferred Portfolio (Delayed Reference Case) performs well across a range of metrics, both in absolute terms and relative to the other candidate portfolios. The Preferred Portfolio was within 3 percent of the lowest-cost portfolio. It ranked 3rd out of 12 portfolios in the 95th percentile cost risk metric. It does not over-rely on purchases or sales of energy or capacity. The Preferred Portfolio maintains 270 MW of reasonably low-cost, dispatchable capacity to support CEI South customers during the worst weeks of each season, providing a physical hedge against high energy prices during peak periods. It also capitalizes on the ability to reuse the interconnection at F.B. Culley 2 while allowing time to reassess regulatory and market conditions during the next IRP.

Importantly, it provides flexibility and optionality as MISO adapts to higher future levels of renewables across the system, allowing more time for other technologies, like long-duration battery storage and small modular reactors, to be commercialized. The ability to retire F.B. Culley 3 provides CEI South with a structured pathway to shift toward a lower-carbon portfolio as technology and regulatory conditions evolve.

The Preferred Portfolio is among the best performing portfolios across multiple measures on the scorecard and provides several additional benefits to CEI South customers and other stakeholders, including that it:

- Presents an affordable portfolio for customers as it limits near-term capital investment resulting in a relatively low incremental energy burden. Of the top five

least-cost portfolios, the Preferred Portfolio shows the smallest range of expected revenue requirements, indicating that it has less price volatility.

- Includes a diverse mix of resources—solar, wind, and energy efficiency—supported by dispatchable generation, storage, and demand response resources; protects against overreliance on the market for energy and capacity.
- Maintains flexibility with multiple off-ramps to adapt to a rapidly evolving industry, including a multi-year resource buildout across several sites and the option to replace F.B. Culley 3 as technology and market conditions change. This flexibility also enables CEI South to respond to new economic development opportunities.
- Hedges against future cost risks and uncertainty by maintaining the F.B. Culley 2 and F.B. Culley 3 interconnection rights.
- Maintains tax base in Warrick County, which is particularly important to the local school system in that county. Moreover, the Preferred Portfolio adds jobs and tax base to Posey County in 2034.
- Allows for continued use of existing plant assets, helping to avoid future potential stranded assets.
- Continues CEI South's energy efficiency programs with near-term energy savings of 1.18% of eligible sales over the next 6 years, and further long-term energy savings opportunities of 1.17% of eligible sales identified over the remaining 14 years of the 20-year period. CEI South is committed to Energy Efficiency to help customers save money on their energy bills and will continue to evaluate this option in future IRPs.
- Continues existing demand response programs, including the DLC Residential AC Switch Program, Residential Bring Your Own Thermostat ("BYOT", also known as the Thermostat Load Control Rider), and the approved Aggregation Demand Response Program launched in September 2025. The portfolio also continues implementation of CPP Time-of-Use rates beginning in 2028; note that the residential pilot is expected to begin in Q2 2026. In addition, a new Commercial Bring Your Own Thermostat program will be introduced, operating consistently with the existing residential thermostat program.

5.1.2. Reliability

Reliability is commonly measured by the ability of a system to meet load without unserved energy. In the probabilistic Risk Analysis, the Preferred Portfolio was tested through Reference Case assumptions as well as different elements from the three alternative scenarios, each of which had widely varying market assumptions for fuel prices, emissions prices, load, and capital costs. In each of these simulations, the Preferred Portfolio consistently met MISO's seasonal PRMR and experienced negligible hours of unserved energy. These results confirm that the portfolio provides reliable service under both expected and stressed operating conditions over the 20-year study horizon.

In the near-term, the portfolio contains two highly dispatchable combustion turbines totaling 460 MW. These units provide fast-ramping capability and can reach full output within ten minutes, offering essential backup to variable renewable generation and serving as a hedge against volatility in both the energy and capacity markets. Following the conversion of these combustion turbines to a combined cycle in 2034, ramp times will lengthen to about 30 minutes, but overall thermal efficiency will increase significantly and have the ability to follow load.

Complementing these units is 90 MW of storage beginning in 2028 along with an additional 100 MW of storage by the end of the study period. These storage resources can dispatch at full output in less than one minute, providing immediate response to fluctuations in renewable output or system contingencies. The portfolio also retains 180 MW of existing combustion turbines, one of which provides black start capability, ensuring resilience during grid restoration or multi-day low-renewable conditions. Collectively, these resources enable the system to meet peak demand during periods of limited solar and wind production and to maintain service during seasonal high-risk weeks.

While not an explicit objective in the balanced scorecard, resource diversity supports reliability by reducing dependence on any single fuel or technology. The Preferred Portfolio achieves a balanced mix of peaking and baseload natural gas, solar, wind, battery storage, and demand-side resources. This diversity mitigates risks such as an extended cloudy period (reducing solar generation) or a fuel disruption that can come from a force majeure event on a gas pipeline that could otherwise compromise system reliability.

CEI South has signed a contract with Enel X to add commercial and industrial demand response resources through the approved Aggregation Demand Response rider. 12 MW were included in the Preferred Portfolio in 2026, increasing to 25 MW in 2027, and CEI South has received twenty customer letters of authorization to begin sharing interval meter data for potential program enrollment. Additionally, CEI South’s AMI system is being further developed to allow for a time-based rate. CEI South is currently developing a pilot program for a voluntary critical peak pricing rate. CPP better aligns the price customers pay for electricity with the cost of producing it by varying the price of electricity based on the time it’s consumed. Customers are charged more for electricity during certain periods of peak demand, encouraging customers to use less energy during critical times. Customers who participate have the opportunity to lower their overall electricity spending by shifting load to lower cost hours. As generation becomes more intermittent and less controllable, it will be more important to shape load in the future. These demand-based options will help to further diversify CEI South’s resource mix.

The Preferred Portfolio also includes a significant amount of local resources, namely the assets at the F.B. Culley and A.B. Brown sites. Local projects provide voltage support, physical hedging against high market prices, and reliability for CEI South's large industrial customers, who comprise nearly half of total load. Local generation also reduces the need to construct new high voltage power lines to bring clean renewable power to our area. These transmission projects take years to complete, often require eminent domain and ultimately cost customers money.

CEI South worked with 1898 & Co. to conduct an analysis and review reliability for several alternative paths at existing CenterPoint sites. This near-term assessment reviewed thermal loadings, voltage, VAR support, and transfer capability. Minimal mitigations were identified in the case of F.B. Culley 2 storage, F.B. Culley 3 remaining operational, and the A.B. Brown generation conversion to a combined cycle. For additional study details, see *Technical Appendix Attachment 2.3 Transmission Study (Confidential)*.

5.1.3. Resilience

The Preferred Portfolio offers CEI South customers a blend of renewable energy along with highly efficient, dispatchable thermal generation to maintain system reliability under a range of operating conditions. The combustion turbines currently at A.B. Brown will continue to offer fast ramping capability when needed. When they transition to baseload resources, following the conversion, they will provide additional spinning reserve benefits by supporting system frequency and replacing generation during sudden outages. The continuation of F.B. Culley 3 through the end of 2034 enhances near-term resilience by supplying dependable, dispatchable capacity and spinning reserve benefits. These dispatchable resources are critical to grid resilience, particularly when intermittent resources experience long duration droughts, periods of sustained high demand, or potential future winter weather events. The Preferred Portfolio also includes a combustion turbine with black start capability, offering an additional degree of increased resiliency and operational flexibility.

The chosen portfolio also maintains both of the existing interconnection rights at F.B. Culley 2 and 3, for 90 MW and 270 MW, respectively. This protects customers from untimely delays associated with a generation resource at another location, especially with the extensive MISO queue delays in recent years due to the record amount of interconnection requests submitted. In addition, it shields customers from potential transmission upgrade costs because the increase in interconnection requests is exhausting available transmission capacity. In addition to preserving these rights for future replacement resources, the continued operation of F.B. Culley 3 provides valuable spinning mass on

CEI South's system, supporting local grid frequency. This makes the local grid more resilient to sudden system disturbances.

5.1.4. Stability

A transmission analysis was performed on four unique groups defined by the operational status of F.B. Culley 3 (retirement or continued operation) and A.B. Brown 5 and 6 (conversion or no conversion). As described in Section 2.8.3.1, short circuit ratio ("SCR") and dynamic reactive power ("VAR") support were used as the primary transmission metrics to assess system stability. The Preferred Portfolio, which includes the conversion of A.B. Brown 5 and 6 at the beginning of 2034 as well as the retirement of F.B. Culley 3 at the end of that same year, performed well in both stability metrics. Notably, the Preferred Portfolio has the second highest dynamic VAR support, indicating strong voltage stability during and after major grid disturbances.

In addition to the scoring assessment, a more detailed transmission study evaluated the system impacts of individual unit retirements and additions. The study found that if F.B. Culley 2 were to retire and no other units were brought online, the transmission system would require about $47.9 million in upgrade costs. These upgrade costs were incorporated into the Preferred Portfolio's NPVRR, recognizing that these expenses could be incurred if the site's planned battery storage remains idle. Including this assumption ensures that the Preferred Portfolio reflects a prudent estimate of potential transmission investment needs.

5.1.5. Environmental Sustainability

The Environmental Sustainability objective was evaluated utilizing the stochastic analysis and is quantified using four metrics:

- CO_2 equivalent emissions (stack emissions) intensity (tons of CO_2e/kWh)
- CO_2 equivalent emissions (tons of CO_2e)
- SO_x emissions (tons of SO_x)
- NO_x emissions (tons of NO_x)

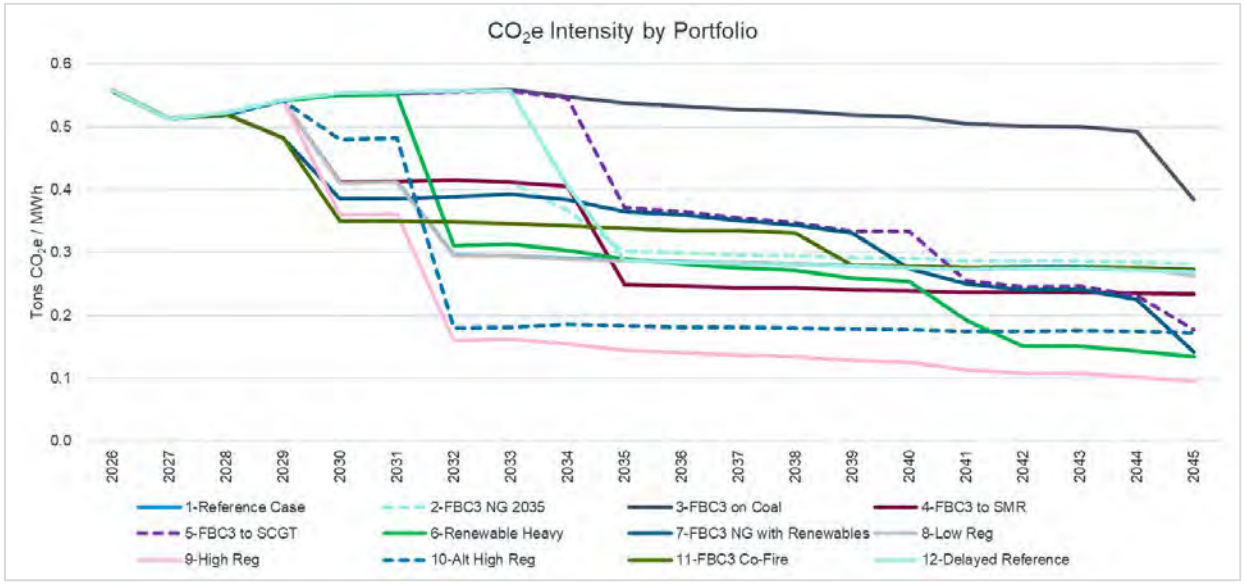
The inclusion of CO_2e is useful as it measures not only CO_2 but other emissions, such as methane and nitrous oxide. Conversion factors were applied to CO_2 from the Electronic Code of Federal Regulations ("eCFR")[39,40] to convert to CO_2 equivalence. All metrics measure the total amount of pollutants that go into the atmosphere over the 20-year planning period rather than at a given point in time.

[39] Methane (CH4) and nitrous oxide (N2O) emission factors for coal (bituminous) and natural gas taken from Table C-1 to Subpart C of 40 CFR Part 98. December 9, 2016.
[40] Chemical-specific Global Warming Potentials ("GWPs") taken from Table A-1 to 40 CFR Part 98 Subpart A for a 100-year time horizon. December 11, 2014.

The Preferred Portfolio performs moderately well in the Environmental Sustainability objective, reducing annual CO_2e emissions by more than 7 million tons over the 2026-2045 study period compared to the BAU portfolio (Portfolio 3). As illustrated by Figure 5-1, the retirement of F.B. Culley 3 at the end of 2034 causes a significant drop in total emissions. During the same year, the conversion of A.B. Brown 5 and 6 combustion turbines to a highly efficient combined cycle also contributes to declining emissions.

By 2035, the Preferred Portfolio was found to reduce CO_2 emissions in the reference case by approximately 72% compared to the baseline year of 2005. This represents an annual reduction of approximately 7.5 million tons of CO_2 from the baseline of 9.6 million tons of CO_2, with the small remainder driven mostly by the A.B. Brown units.

Figure 5-1 – Average CO_2e Emissions Intensity across 200 Draws



5.1.6. Affordability

Affordability is a key objective in the balanced scorecard that is measured as part of the stochastic analysis. The primary measure for affordability is the 20-year NPVRR, which comes from the stochastic mean (average) of 200 iterations of a portfolio as it is simulated in the dispatch model under varying market conditions. Each iteration provides the total annual cost of each component of total portfolio cost, including fuel costs, emissions costs, variable operations and maintenance costs, fixed operations and maintenance costs, energy export revenues (sales), energy import costs (purchases), capacity market sales revenues, and capacity market purchase costs. Each annual cost category is then summed

into a total portfolio cost and discounted by CEI South's weighted average cost of capital to arrive at the NPVRR. The lower the NPVRR is for a portfolio, the lower the rates can be to recoup the cost to serve load over the next 20 years. The stochastic methodology allows for a rigorous analytical framework to determine the affordability of a portfolio.

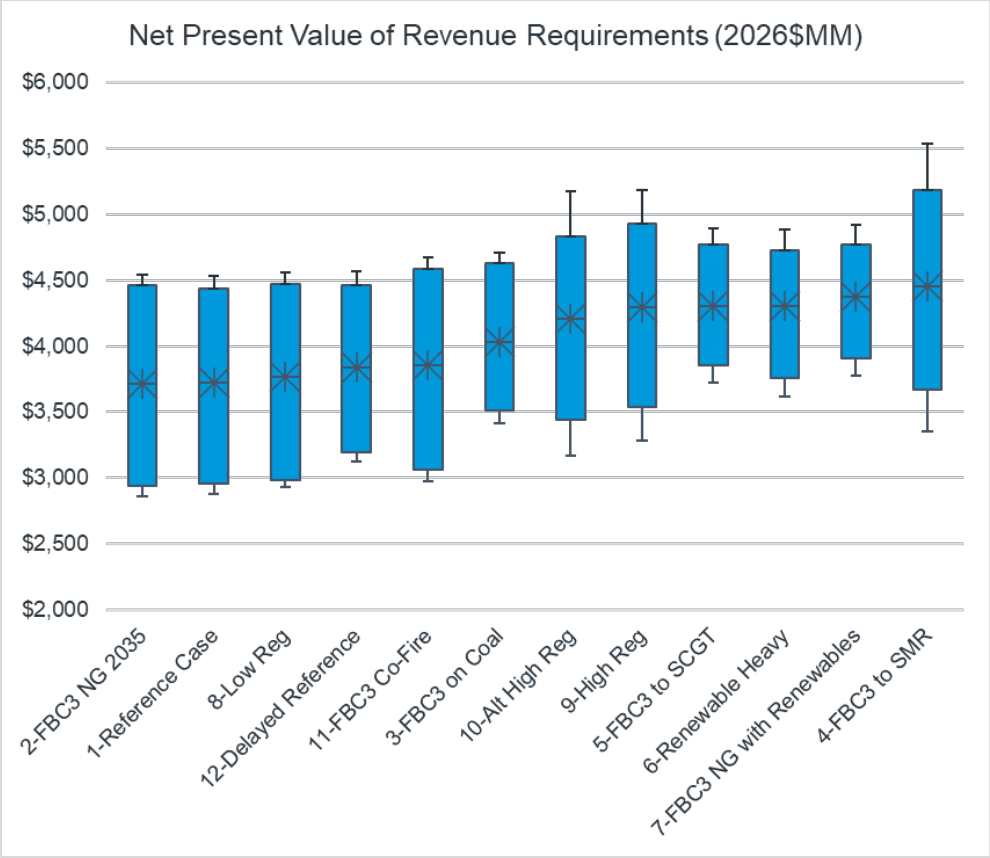
The Preferred Portfolio is within the least-cost portfolios and performs well in the other quantitative affordability metrics including 5th and 95th percentiles of NPVRR and incremental energy burden. Beyond the NPVRR, the Preferred Portfolio mitigates future cost risk through moderate reliance on energy and capacity market sales and using local resources, which have an additional benefit.

5.1.6.1. Portfolio Cost Comparison

Figure 5-2 summarizes NPVRR outcomes from 200 stochastic iterations for each portfolio, showing the minimum, the fifth percentile, the average (indicated by the star), the ninety-fifth percentile, and the absolute maximum. As illustrated in the figure, the Preferred Portfolio has the narrowest range of possible NPVRRs of the top 5 least-cost portfolios. This indicates less variability in future portfolio costs, revealing cost stability among changing market conditions. The 5th percentile of costs is approximately $3.2 billion while the 95th percentile is approximately $4.5 billion, meaning that 90% of the 200 runs created a total net present value of revenue requirements between those two values.

The Preferred Portfolio is among the lowest cost portfolios across the 12 candidates, with a 20-year average NPVRR of $3,836 million. This NPVRR is within 2.9% of the Reference Case portfolio and 3.2% of the least cost portfolio. The Preferred Portfolio is nearly $200 million less expensive than BAU which continues F.B. Culley 3 on coal (the sixth most expensive portfolio in this objective category), which saves customers money in the long-term. Moreover, if sales revenues come in as modeled, the incremental energy burden shows a minimal increase in affordability over both the near and long-term.

Figure 5-2 – Net Present Value of Revenue Requirements for All Portfolios



5.1.6.2. Future Affordability

Moreover, of the top 5 least-cost portfolios, the Preferred Portfolio shows the least reliance on future energy and capacity market sales to lower the NPVRR and make the portfolio more competitive. The greater the energy market sales by a candidate portfolio, the greater the exposure to the risk that energy prices will be lower than the short-run marginal cost of energy production from the CEI South fleet. Similarly, the greater the capacity market purchases that are required by a candidate portfolio, the greater the exposure to the risk that capacity market purchase prices will be higher than the cost of adding capacity to the CEI South fleet.

Figure 5-3 displays the near-term maximum, short-term maximum, and planning horizon average energy market sales expressed as a percent of total generation as well as the net present value of total capacity market sales in dollars. As seen in the Figure 5-3, four of the top five portfolios have an average of 26% of generation contributing to sales and a near-term maximum of 32%. As explained above and validated by the Indiana Commission in

Cause No. 45052, this is a risky proposition for a company of this size. In contrast, CEI South's Preferred Portfolio (12-Delayed Reference) sells a maximum of 17% of total generation in the near-term and averages 23% over the entire study period. Thus, even with lower energy market sales exposure, the Preferred Portfolio's total cost (NPVRR) remains within 3% of the least-cost portfolio.

Figure 5-3 – Portfolio Exposure to Market Sales

Portfolio	Energy Market Sales (%)			Capacity Sales NPV ($M)
	Average	Short Term Max	Long-term Max	
2-FBC3 NG 2035	26%	32%	31%	$217
1-Reference Case	26%	32%	30%	$140
8-Low Reg	26%	32%	30%	$167
12-Delayed Reference	23%	17%	31%	$115
11-FBC3 Co-Fire	26%	32%	31%	$192
3-FBC3 on Coal	15%	18%	18%	$117
10-Alt High Reg	25%	20%	32%	$159
9-High Reg	20%	26%	23%	$128
5-FBC3 to SCGT	14%	17%	18%	$93
6-Renewable Heavy	11%	16%	13%	$95
7-FBC3 NG with Renewables	14%	17%	19%	$106
4-FBC3 to SMR	26%	32%	31%	$171

In contrast, overreliance on market purchases also carries inherent risk. The greater the energy market purchases that are required by a candidate portfolio, the greater the exposure to the risk that energy prices will be higher than the short-run marginal cost of energy production from the CEI South fleet. Similarly, the greater the capacity market sales by a candidate portfolio, the greater the exposure to the risk, if capacity market prices are lower than forecasts the NPV reduction from capacity sales would be lower.

As shown in Figure 5-4, the Preferred Portfolio is moderately reliant on energy market purchases, which, on average over the planning horizon, was about 12% of total generation. While the other least-cost portfolios only had about 10% of total generation from market sales, this is due to the earlier conversion of A.B. Brown, which necessitates

a near-term rate increase. With regard to capacity market purchases, the Preferred Portfolio also performs moderately well. In the first four years of the study, this portfolio has the smallest capacity deficit, largely due to the addition of the firm capacity associated with the F.B. Culley 2 battery. While the ten portfolios that allow for the interconnection rights to expire at F.B. Culley 2 are forecasted to purchase nearly $5 million worth of capacity in 2028 and 2029, the Preferred Portfolio purchases are about half of that during the same time period. Thus, while the Preferred Portfolio includes moderate capacity purchases over the long-term, CEI South will continue to evaluate this path and prioritize affordability following submission of this IRP.

Figure 5-4 – Portfolio Exposure to Market Purchases

Portfolio	Energy Market Purchases (%)			Capacity Purchases NPV ($M)
	Average	Short Term Max	Long-term Max	
2-FBC3 NG 2035	9%	16%	9%	$6
1-Reference Case	10%	17%	11%	$14
8-Low Reg	10%	17%	11%	$6
12-Delayed Reference	12%	21%	11%	$18
11-FBC3 Co-Fire	10%	22%	11%	$12
3-FBC3 on Coal	19%	21%	26%	$22
10-Alt High Reg	9%	17%	5%	$19
9-High Reg	14%	17%	16%	$23
5-FBC3 to SCGT	21%	20%	29%	$26
6-Renewable Heavy	30%	37%	40%	$22
7-FBC3 NG with Renewables	23%	26%	30%	$24
4-FBC3 to SMR	9%	16%	8%	$13

5.1.6.3. Broader Affordability Impacts

Moreover, since the Preferred Portfolio proposes a significant amount of resources located within CEI South's service territory, the customers benefit from reduced congestion cost risk and additional tax base and jobs. Local generation helps to minimize the risks of differences in cost between where power is produced and where it is consumed. When

power is produced on system, customers minimize the likelihood of congestion charges, which can occur when delivering power via the transmission system.

Investing in local projects also helps produce tax base and jobs, which directly benefit the communities CEI South serves. Currently, CEI South primarily operates generation assets in two counties, generating tax revenues in Posey and Warrick counties. The Preferred Portfolio replaces F.B. Culley 2 with a battery storage system, which provides economic benefit to the local community, whereas simply purchasing the capacity from the market does not. Moreover, the Preferred Portfolio provides additional tax base in Posey County due to the A.B. Brown 5 and 6 conversion. Communities where CEI South customers live can utilize this money to support school systems, police, parks and recreation, and other critical support services. Additionally, these projects will continue to be operated by local employees that contribute to the local economy. Finally, the continued operation of F.B. Culley 3 on coal preserves the local tax base and contributes to Indiana's economy through the use of Indiana-mined coal and the associated mining employment.

5.1.7. Other

5.1.7.1. Future Flexibility

The Preferred Portfolio provides a low-cost plan with a great deal of forward-looking flexibility. The inclusion of the battery storage resource at F.B. Culley 2 addresses CEI South's capacity need while also maintaining a valuable MISO interconnection. Maintaining the interconnection avoids future cost risk. This portfolio provides time for other technologies to advance and potentially become more cost competitive as CEI South will reevaluate decisions at F.B. Culley 3 and at A.B. Brown 5 and 6, in a future IRP. This time also allows CEI South to adapt to changing regulatory and market conditions. Until such time, CEI South customers will benefit from the minimal capital investments in the near-term, providing rate stability.

5.1.7.2. Operational Flexibility

In the near term, the Preferred Portfolio includes Variable Energy Resources ("VER") in the form of nearly 400 MW each of solar and wind, balanced by 190 MW of energy storage resources and two 230 MW natural gas combustion turbines that transition into an 850 MW combined cycle gas turbine in 2034. The CT units, batteries, and CCGT can help to smooth out the intermittency of the VERs. The fast-ramping requirements of a system increase as the balance shifts toward increased VERs, particularly solar resources. The phenomenon known colloquially as the "duck curve" demonstrates the need for fast-ramping capability, a role that fast-start resources perform well, to handle the onset of evening peak demand concurrent with rapidly declining solar output. Moreover, the dispatchable CCGT will

provide critical baseload and load-following capability along with a lower emission profile. The high thermal efficiency and quick ramping capability of the unit will stabilize the net load variability and deliver reliable power during extended periods of low wind or solar production. This portfolio is expected to meet all operational flexibility requirements.

Following the conversion of the A.B. Brown combustion turbine units 5 and 6 to a CCGT, CEI South will retain a diverse and flexible set of natural gas units as it will maintain its' existing two 80 MW CT's. These peaking units can be brought online relatively quickly to address short-term fluctuations in demand, complementing the steady output of the CCGT. One of the two peaking units includes black start capability, providing operational flexibility. Maintaining both technologies strengthens operational flexibility, ensuring reliable service across a range of potential market and system conditions.

CEI South considers maintaining an adequate amount of dispatchable generation essential to ensuring reliable service for customers throughout all seasons and operating conditions. CEI South's experience shows that renewable generation can be unpredictable, therefore, a portion of generation should (a) provide a dispatchable (controllable) output (b) be able to start and stop more than once daily and be placed in service quickly and (c) respond to rapid changes in renewable output. Given the healthy number of dispatchable resources in the Preferred Portfolio, CEI South is not only able to meet current system needs but is positioned well to continue to investigate the addition of more intermittent generators on the system should the need arise.

5.1.7.3. Economic Development

The Preferred Portfolio positions CEI South well to provide relatively low-cost power to industrial customers and other large load users. The current plan offers flexibility and a hedge assurance, reducing market risk for customers. Specifically, CEI South must remain nimble and dynamic for prospective industrial customers and planning for the conversion of A.B. Brown 5 and 6 to a CCGT in 2034 provides this agility. CEI South aggressively pursues manufacturing opportunities which have direct, indirect, and induced economic benefits for the region and state of Indiana. CEI South's ability to attract and retain these types of customers is vital to the region's economic wellbeing. Job growth leads to increased earning opportunities for residents and at the same time raises state revenue and tax base. Additionally, large power users can assist all CEI South customers with lower utility rates by spreading the fixed cost recovery requirements for the rate base.

For industrial customers to maintain their required voltage level, the CEI South system must be able to supply an adequate amount of reactive power ("VARs"). Transmission planning studies have shown that this cannot be accomplished without on-network reactive power

supplying facilities, such as local synchronous generation. The CTs in the Preferred Portfolio provide reactive power support. Even when they are not dispatched normally, CTs are able to be started and brought online quickly if needed for CEI South system reliability. Moreover, when the A.B. Brown CTs are converted to a baseload combined cycle in 2034, the dynamic reactive power on the system increases. The A.B. Brown CTs as well as the CCGT also prevents CEI South from entering into Reactive Power Payments through the MISO market, which would impact CEI South customers' bills.

In addition, large customers and site selectors understand the comprehensive risks of market rate pricing and the corresponding volatility. The current IRP plan and the opportunity for future baseload generation allows for customers to remain confident in CEI South's ability to provide safe, reliable, and cost-effective service. CEI South's generation strategy is an essential service for customers and the region's economic growth capability.

5.1.8. Fuel Inventory and Procurement Planning

Prices for commodities such as coal and natural gas are influenced by market conditions and can vary significantly over time, introducing uncertainty into long-term planning. CEI South manages short-term price volatility through coal contract strategies that lock in prices to stabilize costs. Coal suppliers and transportation providers generally require firm commitments on quantities; however, CEI South coal contracts include optionality to adjust tonnage up or down to help manage operational variability which impacts inventory levels. Currently CEI South utilizes non-firm pipeline delivery and gas storage for the existing 80 MW peaking units and firm pipeline delivery and gas storage for the new A.B. Brown CTs. It is planned that the combustion turbines at A.B. Brown, if converted, will continue to utilize firm pipeline supply contracts.



The Alternate Preferred Portfolio

Chapter 6

6.1. Alternate Reference Case Portfolio Development

Following stakeholder feedback, the Alternate Reference Case was developed to evaluate the potential for a large load addition that scales over time. In this scenario, the new, additional load increases in 250 MW increments until it reaches 1,500 MW, while all other market assumptions remain consistent with the Reference Case. To support potential economic development opportunities in Southwestern Indiana, CEI South developed multiple portfolios to explore different pathways for serving future large load growth.

Specifically, five portfolios were considered, each designed to test alternate development pathways under the large load growth assumptions included in the Alternate Reference Case. One portfolio, similar to the scenario-based portfolios discussed earlier, was produced by allowing the model to freely optimize resource additions to create the least-cost portfolio that meets input assumptions. The remaining four portfolios were developed to explore different ways to serve an increased load by directing the model toward specified resource selections and then allowing optimization around those decisions.

The resulting portfolios are summarized in Figure 6-1. Across all portfolios, the model selected to reuse the interconnection rights at F.B. Culley 2 to construct a 90 MW storage facility in 2028, securing capacity to meet load growth and taking advantage of the investment tax credit benefits. The model also exclusively chose to convert the A.B. Brown 5 and 6 CTs to a 2x1 CCGT at the earliest opportunity (2030). This conversion is favorable as it converts the peaking CTs to an efficient CCGT that can serve as a baseload resource, while adding nearly 400 MW of firm capacity to the portfolio. Finally, all portfolios also preferred to keep F.B. Culley 3 operational in some capacity, either as a baseload coal resource or a peaking natural gas unit.

Figure 6-1 – Alternate Reference Case Portfolios

Year	1: Optimization Run	2: 1x1 J Class in 2032	3: Renewables + CT's	4: FB Culley 3 NG Conversion 2030	5: FB Culley 3 NG Conversion 2035
2028	+1 FBC2 Storage (90 MW)	+1 FBC2 Storage (90 MW)	+1 FBC2 Storage (90 MW)	+1 FBC2 Storage (90 MW)	+1 FBC2 Storage (90 MW)
2030	+1 AB Brown7: Fired CCGT 2030 (850 MW)	+1 FB Culley:3 NG 2030 (270 MW) +1 AB Brown7: Fired CCGT 2030 (850 MW)	+1 AB Brown7: Fired CCGT 2030 (850 MW)	+1 FB Culley:3 NG 2030 (270 MW) +1 AB Brown7: Fired CCGT 2030 (850 MW)	+1 AB Brown7: Fired CCGT 2030 (850 MW)
2031			+1 Non IRA Wind + Storage (200 + 100 MW)		
2032	+1 2x1 J Class Fired CCGT (1361 MW)	+1 1x1 J Class Unfired CCGT (568 MW)	+1 Non IRA Wind + Storage (200 + 100 MW)	+1 2x1 J Class Fired CCGT (1361 MW)	+1 2x1 J Class Unfired CCGT (1144 MW)
2033			+5 Non IRA Wind + Storage (1,000 + 500 MW)		+1 2x1 J Class Fired CCGT (1361 MW)
2034		+1 2x1 J Class Unfired CCGT (1144 MW)	+2 Non IRA Wind + Storage (400 + 200 MW)		
2035	+1 J Class SCGT (385 MW)		+1 J Class SCGT (385 MW)	+1 J Class SCGT (385 MW)	+1 FB Culley:3 NG 2035 (270 MW) +1 Non IRA Wind + Storage (200 + 100 MW)
2036					
2037			+1 50 MW 4 Hour Storage (50 MW)		
2039		+1 50 MW 4 Hour Storage (50 MW)			
2040	+1 50 MW 4 Hour Storage (50 MW)		+1 F Class SCGT (222 MW)	+1 Non IRA Wind (Battery) (100 MW) +1 Non IRA Wind (Hybrid) (200 MW)	
2041					+1 50 MW 4 Hour Storage (50 MW)
2042	+1 100 MW 4 Hour Storage (100 MW)	+1 50 MW 4 Hour Storage (50 MW)			
2043					+1 50 MW 4 Hour Storage (50 MW)
2044		+1 50 MW 4 Hour Storage (50 MW)	+1 Non IRA Wind (200 MW)		
2045	+1 FB Culley:3 thru 2045 (270 MW) +1 Non IRA Wind + Storage (200 + 100 MW)	+1 Non IRA Wind + Storage (200 + 100 MW)	+1 FB Culley:3 thru 2045 (270 MW) +1 Non IRA Solar + Storage (100 + 50 MW) +1 Reciprocating Engine (110 MW)	+1 100 MW 4 Hour Storage (100 MW) +1 50 MW 4 Hour Storage (50 MW)	+1 100 MW 4 Hour Storage (100 MW) +1 50 MW 4 Hour Storage (50 MW)

6.2. Portfolio Performance

The five portfolios were evaluated through a similar risk analysis framework as the traditional portfolios in order to test operational performance and affordability under a range of potential market conditions. The market conditions that were varied include fuel costs, capital costs, inclusion of a CO_2 tax, market prices, and allowable energy sales. The methodology and calculations underlying these variations are described in the Risk Appendix section Risk Appendix. The relative performance of each portfolio across these conditions is detailed in Figure 6-2. The inputs into the EnCompass model that were used to generate the following results is given in the *Technical Appendix Attachment 6.1 CEIS 2025 IRP Alternate Reference Stochastics Model (Confidential)*.

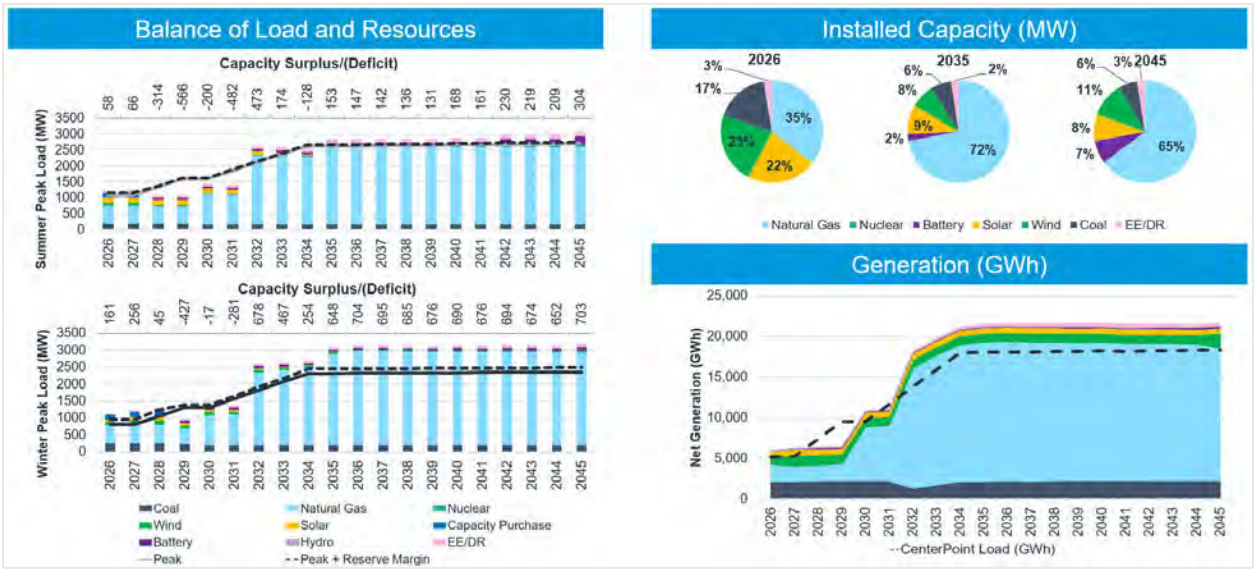
Figure 6-2 – Alternate Reference Case Risk Analysis Scorecard

Objective	Affordability				Environmental Sustainability				Reliability/Resiliency/Stability			Risk/Other			
Portfolio Description	20 Year NPVRR ($M)	Delta From Reference (%)	5% Value of NPVRR ($M)	95% Value of NPVRR ($M)	CO_2 Intensity (Tons CO_2e/MWh)	CO_2 Equivalent Emissions (Stack Emissions) (000s Tons CO_2e)	SOx Emissions (Tons)	NOx Emissions (Tons)	Unserved Energy (MWh)	Spinning Reserve (MW)	Fast Start Capability (MW)	Energy Market Sales (%)	Energy Market Purchases (%)	Capacity Sales NPV ($M)	Capacity Purchases NPV ($M)
1- Optimized Case	$11,652	0%	$10,197	$13,257	0.427	121,201	47,708	26,303	33,860	2,063	614	10.1%	14.2%	$163	$80
2- 1x1 J Class 2032	$12,242	5%	$10,899	$13,674	0.304	93,487	8,890	17,617	41,307	2,227	371	9.7%	14.8%	$122	$112
3- Renewables + CT's	$12,024	3%	$10,510	$13,288	0.335	84,915	51,563	26,813	5,386	1,031	1,269	7.5%	18.1%	$45	$120
4- FBC3 NG 2030	$11,893	2%	$10,573	$13,355	0.304	92,840	9,123	17,187	38,787	2,063	612	9.7%	14.9%	$168	$79
5- FBC3 NG 2035	$11,659	0%	$10,401	$13,119	0.296	82,899	21,563	10,358	25,466	1,868	556	9.7%	14.3%	$130	$100

1: Average net present value of portfolio revenue requirements from 2026 to 2045
2: Percent difference between average NPVRR of portfolio and reference
3-4: Fifth and ninety-fifth percentiles of net present value of NPVRR to show cost uncertainty
5: Quotient of average CO_2e from generation and average fleet generation from 2026 to 2045
6-8: Total CO_2 equivalent, SO_x, and NO_x emissions from 2026-2045
9: Total emergency unserved energy purchased from 2026 to 2045
10: Capacity from “spinning” thermal assets that can be ramped up or down (combined cycle, coal, nuclear)
11: Capacity from “fast start” assets that can be dispatched quickly (combustion turbine, battery)
12-13: Dynamic VAR support and short circuit ratio from transmission reliability analysis
14: Total energy sales as a percentage of total energy generation from 2026 to 2045
15: Total energy purchases as a percentage of total load from 2026 to 2045
16-17: Net present value of capacity sales and purchases from 2026 to 2045

The optimized portfolio (Preferred Portfolio) developed for the Alternate Reference Case ranks as the least-cost option for meeting rapid load growth. This portfolio retains the F.B. Culley 2 interconnection rights by installation of a battery energy storage resource by 2028, avoiding future cost risk and providing additional reliability to the system. It also maintains the operation of F.B. Culley 3 on coal throughout the entire study period. Though this outcome is less favorable from an environmental perspective, it preserves flexibility for CEI South to revisit this critical decision point in a future IRP cycle as regulatory, market, and technology conditions evolve. The 2030 conversion of A.B. Brown 5 and 6 provides benefits beyond energy and capacity, including the creation of additional jobs and tax base in Posey County. As seen in Figure 6-3, the portfolio, similar to all alternate reference case portfolios, relies on market capacity and energy purchases in the short-term. These needs would most likely be filled by fixed capacity or energy contracts.

Figure 6-3 - Alternate Reference Case Preferred Portfolio Results Dashboard



6.2.1. Transmission System Impact of the Large Load Additions

To assess system reliability, a thorough transmission study evaluated the shoulder, summer, and winter scenarios for various possible large loads. This includes a near-term addition of 300 MW and a 1,000 MW on the West side of the transmission system along with a long-term study of 300 MW and a 1,500 MW on either the West or East side of the system. Similar to previously mentioned studies, this was performed using the MTEP 2024 model, PSS/E software for power flow analysis, and the MISO MTEP 2025 cost guide for component price estimates.

The results indicated that the addition of a 300 MW load on either side of CEI South's system did not require upgrades to the transmission system, while the larger loads did necessitate transmission mitigation (See *Technical Appendix Attachment 6.2 Large Load Study Results (Confidential)*). The Preferred Portfolio's inclusion of the A.B. Brown 2x1 combined cycle and additional large thermal resources located on CenterPoint's system led to required transmission mitigation and upgrade costs of $15.2 to $16.4 million. In contrast, if a large thermal resource were not added to the local system, transmission costs would increase roughly tenfold due to the need for major system reinforcements to accommodate heavy power imports from neighboring regions. Specifically, on the West side of the system, a cost of $152 million would be required to serve a near-term 1,000 MW load while a cost of $147 million would be required to serve a long-term 1,500 MW load. These estimates are for the transmission upgrade costs studied in the transmission portfolio and do not include the costs associated with on- or off-system generation needed to meet the energy and capacity needs of the large load.

For a large load located on the East side of the system, there are unresolvable low-voltage issues, indicating a need for a large generator on the system. The costs resulting from this transmission analysis were not factored into the NPVRR, as the location and timing of the load are speculative. Since the costs would affect all generation portfolios evenly, the relative ranking of portfolio performance stands.

6.2.2. Generation Planning for Large Loads

In addition to the Alternate Reference Case portfolios, a series of large load sensitivities were also conducted to evaluate how the timing and magnitude of new load additions influence resource decisions. Load increases of 100 MW, 300 MW, and 1,000 MW were evaluated. The sensitivities were constructed primarily to provide insight into model behavior and were not included in the Risk Analysis. Three important trends emerged during this sensitivity analysis:

1. In all cases, the model selected the conversion of A.B. Brown from combustion turbines to a combined cycle natural gas plant. This conversion adds nearly 400 MW of firm capacity and provides a reliable baseload resource to support opportunities for economic development.
2. For future load additions greater than 300 MW, the preferred pathway at F.B. Culley 3 shifted from retirement to continued operation throughout the entire study period, preserving flexibility for future replacement or conversion.
3. For future load additions greater than 1,000 MW, the decision to install a battery at F.B. Culley 2 became part of the least-cost portfolio. The early procurement of additional capacity increases system flexibility and contributes valuable firm capacity to CEI South.

6.3. Description of the Alternate Reference Case Preferred Portfolio

The Alternate Preferred Portfolio utilizes the interconnection at F.B. Culley 2 for a 90 MW battery storage unit by 2028, calls for the conversion of A.B. Brown units 5 and 6 gas turbines to an efficient CCGT unit by 2030, and continues to operate F.B. Culley 3 on coal. Beyond these resources, the portfolio calls for the addition of a large natural gas combined cycle in 2032 as the load continues to rapidly increase. In the latter years of the planning horizon, a smaller simple cycle gas unit is added in 2035, and a cumulative 150 MW of standalone storage is procured. In the final study year, an additional hybrid wind plus storage facility is brought online to fill energy and capacity needs.

This generation fleet is complemented by energy efficiency and demand response programs. These demand-side resources include the seven near-term (2026-2027) programs included in the previously approved plan, as well as nineteen additional programs across the commercial, residential, and income-qualified sectors throughout the rest of the planning horizon. Collectively, these programs account for 46 MW of capacity in the first year of the study period and scale up to 118 MW by 2045.

The alternate preferred portfolio offers a least-cost and extremely flexible pathway to meeting additional load. The critical decisions at existing assets match those made in the Preferred Portfolio: F.B. Culley 2 storage, A.B. Brown conversion, and maintaining the F.B. Culley 3 interconnection. This consistency between the two preferred pathways highlights the flexibility in the plan.

It provides a number of benefits to CEI South customers and other stakeholders, beyond what is seen on the balance scorecard, including that it:

- Preserves maximum future flexibility, keeping Southwestern Indiana competitive and able to quickly adapt to support economic development and growth.
- Adds tax base and jobs in our community, helping customers thrive. Both the addition of prospective customers and the additional infrastructure necessary to support it drives economic growth.
- Aligns with current Federal and State goals.
- Utilizes the existing asset at F.B. Culley 3 until future replacement or conversion to natural gas is decided, which will be re-analyzed in subsequent IRPs.
- Adds efficient on-system base load generation through the conversion of A.B. Brown 5 and 6 to a CCGT, which promotes system reliability and provides competitively priced energy that is projected to be consistently lower than market prices.
- Maintains future flexibility with several off ramps to accommodate a rapidly evolving industry and includes a multi-year build out of resources on several sites,

maintaining the option to replace Culley 3 in the future when appropriate, based on continual evaluation of changing technology and conditions.

- Maintains tax base in Warrick County, which is particularly important to the local school system in that county.
- Allows for continued use of existing plant assets, helping to avoid future potential stranded assets.
- Continues CEI South's energy efficiency programs with near-term energy savings of 1.18% of eligible sales over the next 6 years, and further long-term energy savings opportunities of 1.17% of eligible sales identified over the remaining 14 years of the 20-year period. CEI South is committed to energy efficiency to help customers save money on their energy bills and will continue to evaluate this option in future IRPs.
- Continues existing demand response programs, including the DLC Residential AC Switch Program, Residential Bring Your Own Thermostat ("BYOT", also known as the Thermostat Load Control Rider), and the approved Aggregation Demand Response Program launched in September 2025. The portfolio also continues implementation of Residential CPP Time-of-Use rates; the pilot is expected to begin in Q2 2026. In addition, a new Commercial Bring Your Own Thermostat program will be introduced, operating consistently with the existing residential thermostat program.

At this time, no contract to secure a large load has been executed. CEI South will continue ongoing conversations with prospective customers. This large load analysis will continue to evolve as the company continues to evaluate possible load additions, timelines, and costs necessary to serve. While the alternate preferred portfolio provides great insight into a possible path, the resource mix used to serve the potential customer will be heavily influenced by the balance of the customer's needs and priorities. As discussions continue, CEI South will work to prioritize affordability for its existing customers and minimize future cost risk should conversations advance to negotiations or contracting.



Short Term Action Plan

Chapter 7

7.1. Differences Between the Last Short Term Action Plan from What Transpired

Since the last IRP was filed there have been significant challenges in moving forward with key pieces of the last two IRP Preferred Portfolios. First, several solar projects have been terminated due to market dynamics that caused prices to escalate beyond what the Commission approved and beyond where CEI South believed to be affordable 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 similar upward pricing pressure; after years of negotiation and a re-evaluation of this project in this IRP, CEI South opted to walk away from this project in an effort to keep customer rates as affordable as possible in the near to mid-term.

CEI South conducts the IRP process every three years and each IRP, necessarily builds on the previous IRP and the generation resource investments that have come before. The Preferred Portfolio in CEI South's previous 2022/2023 IRP concluded that a generation transition with the conversion of F.B. Culley 3 from coal to natural gas, along with DSM, wind, and solar resources. CEI South began implementing this 2022/2023 IRP by filing two cases seeking approval for (1) signed purchase power agreements ("PPA") for two wind facilities totaling 317 MWs, the Galesburg Wind Project and the Salt Creek Wind Project. (2) CEI South sought and received approval for the 2025-2027 DSM Plan. Each of these filings was consistent with the 2022/2023 IRP, and as noted below, this IRP affirms the direction taken by CEI South. These remaining renewable resources from prior IRPs still qualify for Federal incentives, which dramatically lowered the cost of these renewable resources relative to what could be acquired in the future, post elimination of IRA tax incentives for wind and solar resources.

In preparation for retirement, CEI South submitted an Attachment Y to MISO to suspend operations of its smallest, least efficient coal unit, F.B. Culley 2. This unit is slated for retirement at the end of 2025, consistent with the last IRP. A key decision in this IRP is to determine how to replace this unit and whether or not to preserve the existing interconnection to the grid. CEI South will have approximately three years to replace the unit, preserving the interconnection. Options that were available, meeting limited space requirements, were small gas units (reciprocal engines or aero derivative) or battery storage.

7.1.1. Culley 3 Conversion

In the last IRP CEI South selected a Preferred Portfolio that converted F.B. Culley 3, a 270 MW coal plant, to natural gas by 2027. Given the inputs and likely potential future at that time, this was a competitive option. As CEI South observed increased change and uncertainty, it decided to pause on the conversion and not seek a certificate of convenience and necessity to gain approval from the IURC. CEI South chose to re-evaluate this option within this IRP. While coal to gas conversion may make sense in the future, it does not today. As discussed in this IRP, the conversion with renewables today is projected to be 14% higher cost than the Preferred Portfolio. CEI South will reevaluate this option in its next IRP.

7.1.2. Posey Solar and Two New CTs

CEI South brought Posey solar (191 MW) and A.B. Brown unit 6 (230 MW) online at the end of May 2025. A.B. Brown unit 5 (230 MW) came online at the end of August, consistent with expectations from the last IRP. All three new units have been performing well since coming online.

7.1.3. DSM

The 2022/2023 IRP did support continued energy efficiency programs designed to save 1.1% of eligible retail sales. CEI South proposed the 2025-2027 Electric DSM Plan (*Technical Appendix Attachment 3.4*) to obtain approval of programs to achieve this level of savings. The Commission approved this plan on March 26, 2025 in Cause No. 46100. Consistent with the 2022/2023 IRP, the framework for the 2025-2027 filed plan was modeled at a savings level of 1.1% of retail sales adjusted for an opt-out rate of 77% eligible load. Additionally, CEI South updated all of its DR tariffs in Cause No. 45990 to provide more consistency, to open them to a wider range of potential customers, and to align with changes in the MISO Business Practices Manual. Additionally, CEI South received approval in the same cause to offer DR aggregation to C&I customers and have signed a contract to begin working with Enel X as the program implementer. Enel X began outreach and enrollment in October and has signed a letter of authorization with twenty customers to begin sharing meter data to explore energy plans and contracts and has five customers with a signed contract.

7.2. Discussion Of Plans For The Next 3 Years

7.2.1. Procurement of Resources

CEI South has continued to diversify its portfolio of resources with two wind projects identified in its last IRP. On November 5, 2005 the Commission approved the Salt Creek Wind Project purchase power agreements (“PPA”). That, along with the Galesburg Wind

PPA is expected to come online in 2026, bringing a total of 317 MW of additional clean renewable wind energy to serve our customers. Additionally, the Wheatland solar PPA project is expected to come online at the end of Q1 2026.

7.2.2. RFPs and Continued Evaluation of F.B. Culley 2 interconnection

At the end of 2025 CEI South will place F.B. Culley 2 in suspension with the plans of transferring the interconnection to a 90 MW battery storage unit before the end of 2028. This will require CEI South to replace its existing Attachment Y with an Attachment X. CEI South plans to utilize the results of RFPs for capacity and for a new RFP for battery storage unit to further evaluate the economics and reliability attributes of this option relative to purchasing required capacity to maintain reliability. Pending the results of this analysis, CEI South may file a CPCN for a 90 MW battery storage unit at F.B. Culley and have a COD by the end of 2028.

7.2.3. DSM

CEI South filed for and received approval on March 26, 2025 for a 3-year DSM Plan for 2025-2027 with energy efficiency savings guided by the 2022/2023 IRP process. The CEI South Oversight Board, including the OUCC, CAC and CEI South, will oversee the implementation of energy efficiency programs. CEI South will file a 3-year DSM Plan for 2028-2030 the first half of 2027 consistent with energy efficiency savings guided by the Preferred Portfolio in the 2025 IRP. The Aggregation Demand Response Rider is a 5-year contract and will be ongoing until the end of the contract in 2030, at which time the program will be re-evaluated.

7.2.4. Other Innovative Rate Design

CEI South has been actively working to develop a TOU CPP Pilot program that is set to begin in Q2 2026. CEI South utilized its continuous improvement and project management teams to work collaboratively with business units to build out the necessary infrastructure to support the pilot, including development of a new system to execute CPP events and help facilitate customer enrollment. CEI South will work through the pilot over the next one to two years in the hopes of expansion, if the pilot is successful. Results of the pilot will be included in the next IRP; if the pilot is successful and the next IRP continues to indicate that the program is beneficial for customers, CEI South will propose to expand the rate to the majority of its residential customers in the next general rate case following the next IRP.

7.2.5. Demand Response

CEI South will continue to work with its demand response aggregator in the hopes of attracting C&I customers to participate. This IRP included an indicative amount of industrial DR for this program.

7.2.6. Ability to Finance the Preferred Portfolio

The Company expects to have sufficient funds to finance the Preferred Portfolio through a combination of internally generated cash flow from operations, external capital markets activity, and capital contributions from its parent company. CEI South's secured debt ratings are currently A1/A with a stable outlook from Moody's Investors Services and S&P Global Ratings, respectively.

7.2.7. Continuous Improvement

CEI South works hard on continuous improvement and will take the feedback that we receive on this IRP into consideration as we develop the next IRP. We appreciate formal or informal comments from active stakeholders and what is received through the Director's report. They will be used as the basis for continuous improvement going forward.

7.3. Schedule

Below is a general timeline for implementation of the Preferred Resource Portfolio, subject to change.

Figure 7-1 - Implementation Schedule

Timing	Activity Type	Actions
Q3 2025	Demand Response	Initiation of DR aggregator program
Q1 2026	Generation Transition	Salt Creek Wind (170 MW PPA) online Wheatland Solar (150 MW PPA) online
Q1 – Q2 2026	Storage RFP	Conduct an RFP for storage at F.B. Culley 2. If determined to be affordable, submit a Certificate of Public Convenience and Necessity (CPCN) for 90 MW battery storage in Q3.
Q1 – Q2 2026	Demand Response	Planned implementation of DR aggregator program
Q2 2026	Rate Design	Planned implementation of TOU CPP Pilot program
Q2 – Q3 2026	Generation Transition	Galesburg Wind (147 MW PPA) online
Q1 – Q2 2027	DSM Plan	File a 3-year DSM plan for 2028 through 2030 informed by the 2025 IRP in the first half of 2027
Ongoing	Large Load Addition	Continue to work through due diligence for possible large load addition



Technical Appendix

Chapter 8

8.1. Load Forecast Appendix

8.1.1. Forecast Inputs

8.1.1.1. Energy Data

Historical CEI South sales and revenues data were obtained through the billing system. The billing system contains detailed customer information including rate, service, North American Industrial Classification System ("NAICS") codes (if applicable), usage and billing records for all customer classes (more than 15 different rate and customer classes). These consumption records were compiled in a spreadsheet on a monthly basis. The data was then organized by rate code and imported into the load forecasting software.

8.1.1.2. Economic and Demographic Data

Economic and demographic data was obtained from S&P Global (formerly IHS Markit) for the state of Indiana and the Evansville Metropolitan Statistical Area ("MSA"). S&P Global is a trusted source for economic data that is commonly utilized by utilities for forecasting electric sales. The monthly data provided to CEI South contains both historical results and projected data throughout the IRP forecast period. This information is input into the load forecasting software and used to project residential, commercial (GS) and industrial (large) sales.

8.1.1.3. Weather Data

Historical and normal Heating Degree Days ("HDD") and Cooling Degree Days ("CDD") are derived from daily temperature data for the Evansville airport. HDDs are defined as the number of degrees below a base temperature for a given day. CDDs are defined as the number of degrees above a base temperature for a given day. Normal degree-days are calculated by averaging the historical daily HDD and CDD over the last twenty years. Historical weather data is imported into the load forecasting software and is used to normalize the past usage of residential and GS customers. Similarly, the projected normal weather data is used to help forecast the future weather normalized loads of these customers.

In reviewing historical weather data, Itron found a statistically significant positive, but slow, increase in average temperature. This translated into fewer HDD and more CDD over time. Itron's analysis showed HDD are decreasing 0.4% per year while CDD are increasing 0.5% per year. These trends were incorporated into the forecast. Starting normal HDD were allowed to decrease 0.4% over the forecast period while CDD increased 0.5% per year through 2045. Figure 8-1 and Figure 8-2 show historical and forecasted monthly HDD and CDD.

Figure 8-1 - Heating Degree Days

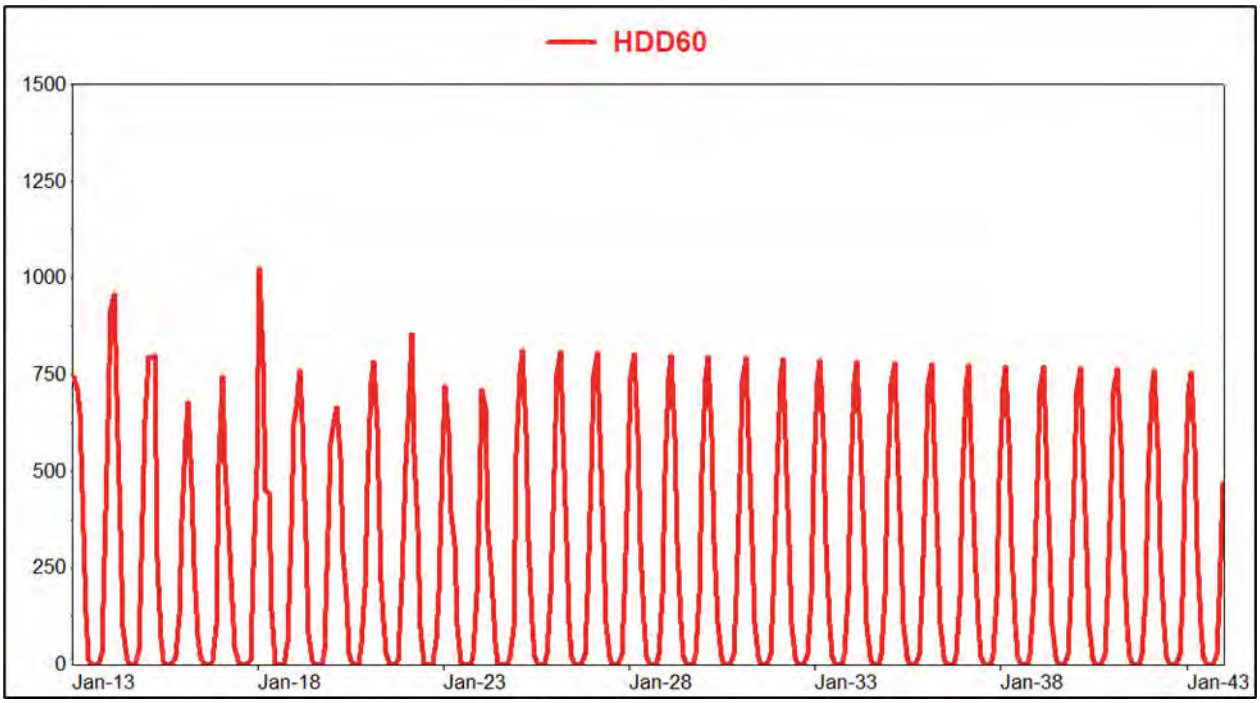
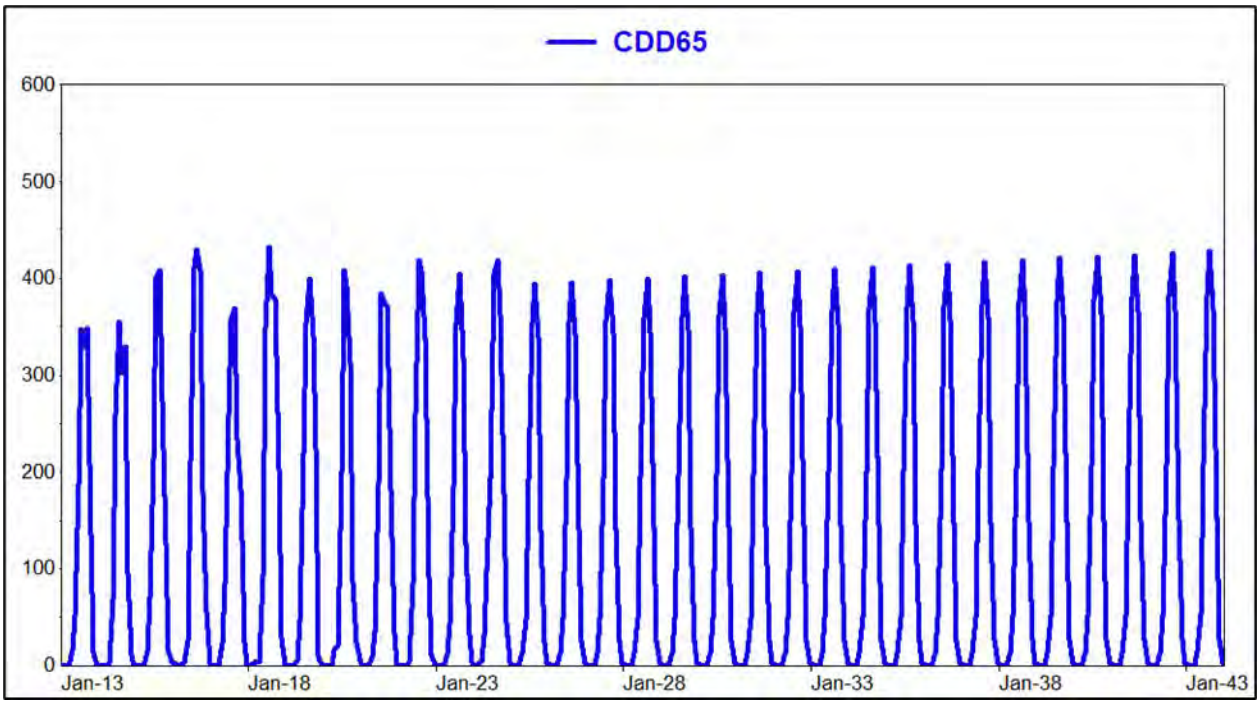


Figure 8-2 - Cooling Degree Days



8.1.1.4. Equipment Efficiencies and Market Shares Data

Itron Inc. provides regional EIA historic and projected data for equipment efficiencies and market shares. This information is used in the residential average use model and GS sales model. CEI South conducted an Electric Baseline survey in the third quarter of 2016 of CEI South's residential customers. This data was utilized to compare its territory market share data with the regional EIA data. To increase the accuracy of the residential average use model, regional equipment market shares were altered to reflect those of CEI South's actual territory.

8.1.1.5. Load Forecast Continuous Improvement

Itron continues to improve and evolve the SAE modeling framework. In addition to annually updating efficiency and saturation projections with the latest estimates from the EIA the framework has evolved to include utility specific DSM program activity data. The inclusion of a utility specific DSM variable in the modeling specification greatly improves model fit and enables the model to produce a baseline forecast excluding the impact of future DSM program activity. Additionally, Itron built a framework for the inclusion and use of trended normal weather where historical weather patterns show this to be appropriate. The CEI South forecast now considers emerging technologies: customer distributed generation and electric vehicles. Customer owned PV adoption is modeled as a function of simple payback. The model explains historic adoption well and provides a framework that considers projected PV installation costs, electric prices and incentives. The adoption of electric vehicles is based on the EIA's forecast of vehicle stock. The EIA's has robust transportation model that includes a vehicle manufacturer component and a consumer choice component to estimate the mix of vehicles by powertrain type: gasoline, diesel, electric, plug-in hybrid electric, etc. The model accounts for projected fuel prices, electric prices, the decline in battery costs and federal incentives for electric vehicles.

Additionally, CEI South continually stays up to date with load forecasting topics in a variety of ways. First, CEI South is a member of Itron's Energy Forecasting Group. The Energy Forecasting Group contains a vast network of forecasters from around the country that share ideas and study results on various forecasting topics. Forecasters typically attend an annual meeting that includes relevant topic discussions along with keynote speakers from the EIA and other energy forecasting professionals. The meeting is an excellent source for end-use forecasting directions and initiatives, as well as a networking opportunity. CEI South forecasters periodically attend continuing education workshops and webinars on various forecasting topics to help improve skills and learn new techniques. Additionally, CEI South discusses forecasts with the State Utility Forecasting Group and other Indiana utilities to better understand their forecasts. CEI

South compares CEI South model assumptions and results to these groups to gain a better understanding of how they interpret and use model inputs.

8.1.2. Overview of Past Forecasts

The following tables outline the performance of CEI South's energy and demand forecasts over the last several IRPs by comparing Weather Normalized ("WN") sales and demand figures to IRP forecasts from 2015-2024.

Weather-normalization is performed each month in order to analyze the variance from the forecast without the impact of weather. This is done by combining customer count, meter read schedule, billing month sales and daily temperature with estimates of the impact of changes in usage to variations of temperature. Underlying the estimates are average use models. Separate models have been estimated for residential and general service customer classes. These models have been estimated from historical billed sales and customer data. Actual weather data from NOAA is used to generate daily use per customer estimates for the revenue classes. The results are used to predict daily use estimates and are used to allocate billed monthly sales to the calendar-month period. The models are also executed using normal daily temperatures.

The following tables show the WN[41] and forecasted values for:

- Total Peak Demand
- Total Energy
- Residential Energy
- GS Energy
- Large Energy

[41] Note that large sales are not weather normalized.

Figure 8-3- Total Peak Demand Requirements (MW), Including Losses and Street Lighting

Year	2014 IRP Forecast	2016 IRP Forecast	2019 IRP Forecast	2022 IRP Forecast	WN Results (MW)	2014 % Diff.	2016 % Diff.	2019 % Diff.	2022 % Diff.
2015	1,155				1,113	-3.8%			
2016	1,156				1,087	-6.3%			
2017	1,113	1,082			1,038	-7.2%	-4.3%		
2018	1,109	1,086			1,006	-10.2%	-7.9%		
2019	1,106	1,085			1,039	-6.4%	-4.5%		
2020	1,106	1,088	1,106		990	-11.8%	-9.9%	-11.7%	
2021	1,106	1,084	1,107		998	-10.8%	-8.5%	-10.8%	
2022	1,107	1,083	1,129		1,013	-9.2%	-6.9%	-11.4%	
2023	1,107	1,083	1,168	1,010	1,052	-5.2%	-2.9%	-11.0%	4.0%
2024	1,107	1,084	1,172	1,087	1,070	-3.5%	-1.3%	-9.5%	-1.6%
Mean Absolute Error						7.4%	5.8%	10.9%	1.2%

Figure 8-4- Total Energy Requirements (GWh), Including Losses and Street Lighting

Year	2014 IRP Forecast	2016 IRP Forecast	2019 IRP Forecast	2022 IRP Forecast	WN Results (GWh)	2014 % Diff.	2016 % Diff.	2019 % Diff.	2022 % Diff.
2015	5,914				5,773	-2.4%			
2016	5,936				5,725	-3.7%			
2017	5,514	5,257			5,073	-8.7%	-3.6%		
2018	5,503	5,290			5,139	-7.1%	-2.9%		
2019	5,494	5,294			4,965	-10.6%	-6.6%		
2020	5,497	5,319	5,400		4,788	-14.8%	-11.1%	-12.8%	
2021	5,492	5,302	5,405		4,923	-11.6%	-7.7%	-9.8%	
2022	5,494	5,303	5,527		4,834	-13.7%	-9.7%	-14.3%	
2023	5,494	5,308	5,755	4,725	4,793	-14.6%	-10.7%	-20.1%	1.4%
2024	5,496	5,320	5,784	5,164	5,096	-7.9%	-4.4%	-13.5%	-1.3%
Mean Absolute Error						9.5%	7.1%	14.1%	0.0%

Figure 8-5- Residential Energy (GWh)

Year	2014 IRP Forecast	2016 IRP Forecast	2019 IRP Forecast	2022 IRP Forecast	WN Results (GWh)	2014 % Diff.	2016 % Diff.	2019 % Diff.	2022 % Diff.
2015	1,404				1,444	2.8%			
2016	1,394				1,416	1.5%			
2017	1,383	1,407			1,398	1.1%	-0.6%		
2018	1,377	1,395			1,375	-0.2%	-1.5%		
2019	1,374	1,384			1,372	-0.1%	-0.9%		
2020	1,373	1,375	1,386		1,408	2.5%	2.3%	1.5%	
2021	1,370	1,366	1,376		1,417	3.3%	3.6%	2.9%	
2022	1,373	1,362	1,378		1,378	0.4%	1.2%	0.0%	
2023	1,377	1,359	1,382	1,433	1,402	1.8%	3.1%	1.4%	-2.2%
2024	1,383	1,359	1,390	1,453	1,446	4.3%	6.1%	3.9%	-0.5%
Mean Absolute Error						1.7%	1.7%	1.9%	1.4%

Figure 8-6- Commercial (GS) Energy (GWh)

Year	2014 IRP Forecast	2016 IRP Forecast	2019 IRP Forecast	2022 IRP Forecast	WN Results (GWh)	2014 % Diff.	2016 % Diff.	2019 % Diff.	2022 % Diff.
2015	1,304				1,321	1.3%			
2016	1,320				1,281	-3.0%			
2017	1,315	1,315			1,278	-2.9%	-2.9%		
2018	1,311	1,324			1,235	-6.1%	-7.2%		
2019	1,308	1,326			1,184	-10.5%	-12.0%		
2020	1,311	1,325	1,280		1,117	-17.4%	-18.7%	-14.7%	
2021	1,310	1,321	1,284		1,165	-12.4%	-13.4%	-10.1%	
2022	1,313	1,322	1,290		1,156	-13.5%	-14.3%	-11.6%	
2023	1,315	1,324	1,294	1,186	1,124	-17.0%	-17.8%	-15.1%	-5.5%
2024	1,320	1,330	1,300	1,186	1,179	-12.0%	-12.9%	-10.3%	-0.6%
Mean Absolute Error						9.4%	12.4%	12.3%	3.1%

Figure 8-7- Industrial (Large) Energy (GWh)

Year	2014 IRP Forecast	2016 IRP Forecast	2019 IRP Forecast	2022 IRP Forecast	WN Results (GWh)	2014 % Diff.	2016 % Diff.	2019 % Diff.	2022 % Diff.
2015	2,916				2,722	-7.1%			
2016	2,932				2,722	-7.7%			
2017	2,546	2,211			2,097	-21.4%	-5.5%		
2018	2,547	2,252			2,182	-16.7%	-3.2%		
2019	2,546	2,270			2,073	-22.8%	-9.5%		
2020	2,549	2,312	2,348		1,971	-29.3%	-17.3%	-19.1%	
2021	2,550	2,317	2,360		2,041	-25.0%	-13.5%	-15.6%	
2022	2,550	2,322	2,464		2,015	-26.5%	-15.2%	-22.2%	
2023	2,549	2,329	2,670	1,793	1,986	-28.4%	-17.3%	-34.5%	9.7%
2024	2,546	2,334	2,682	2,189	2,244	-13.5%	-4.0%	-19.5%	2.5%
Mean Absolute Error						19.8%	10.7%	22.2%	6.1%

8.1.3. Actual and Weather Normalized Energy and Demand Levels

Figure 8-8- Historic Peak Demand

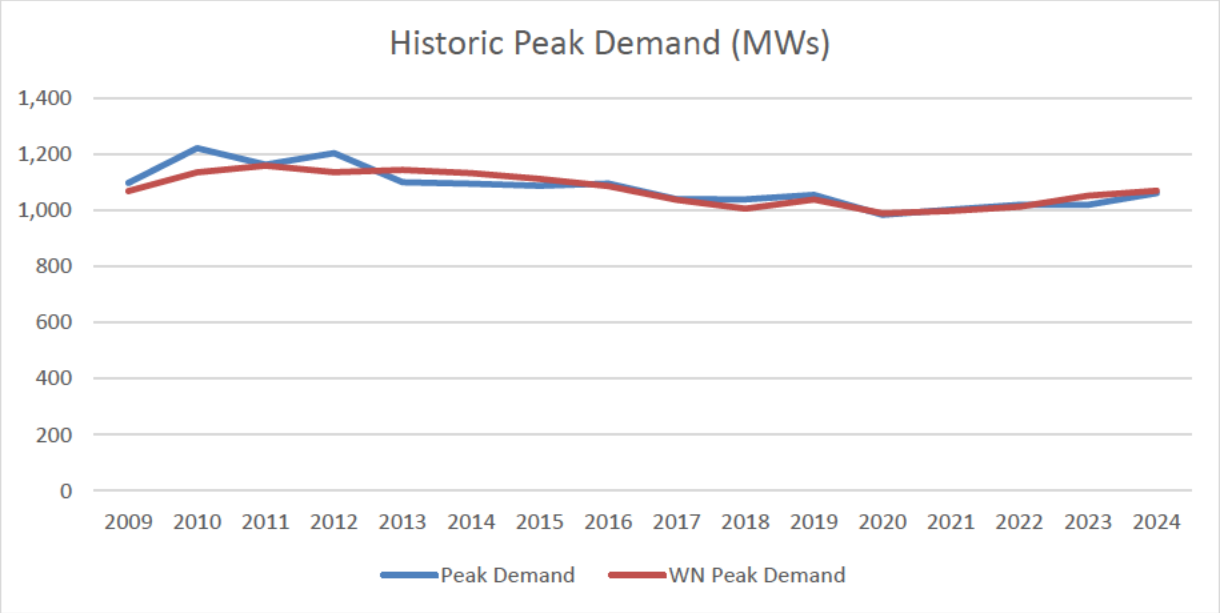
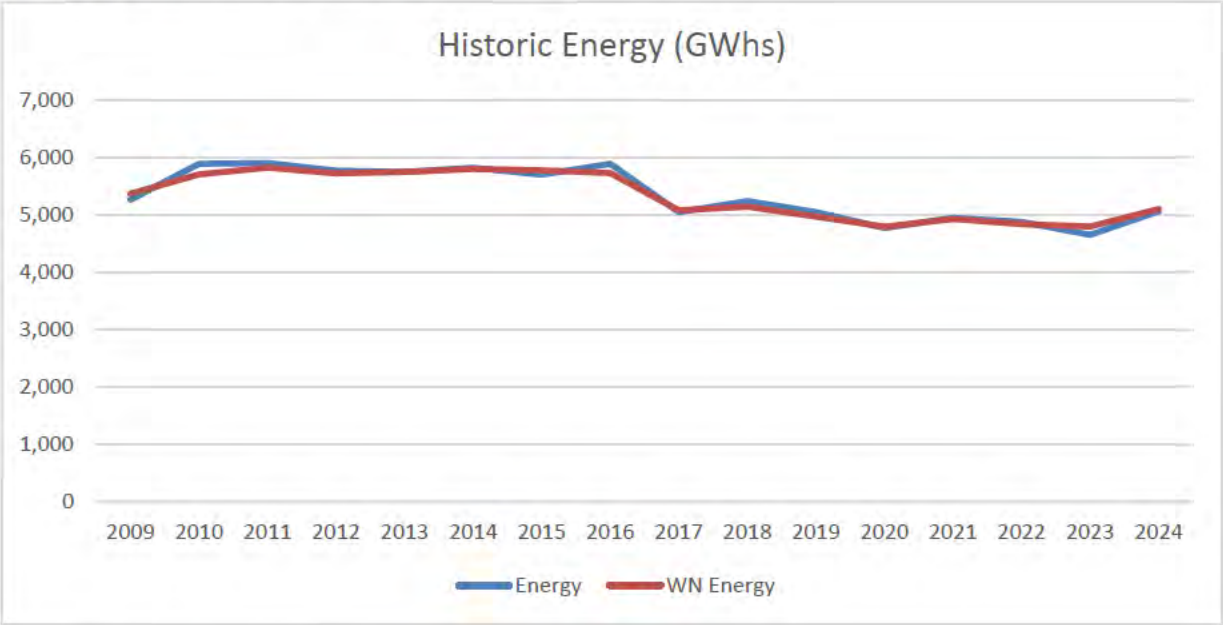


Figure 8-9- Historic Energy



8.1.4. Load Shapes

Figure 8-10- Historic Annual Load Shape

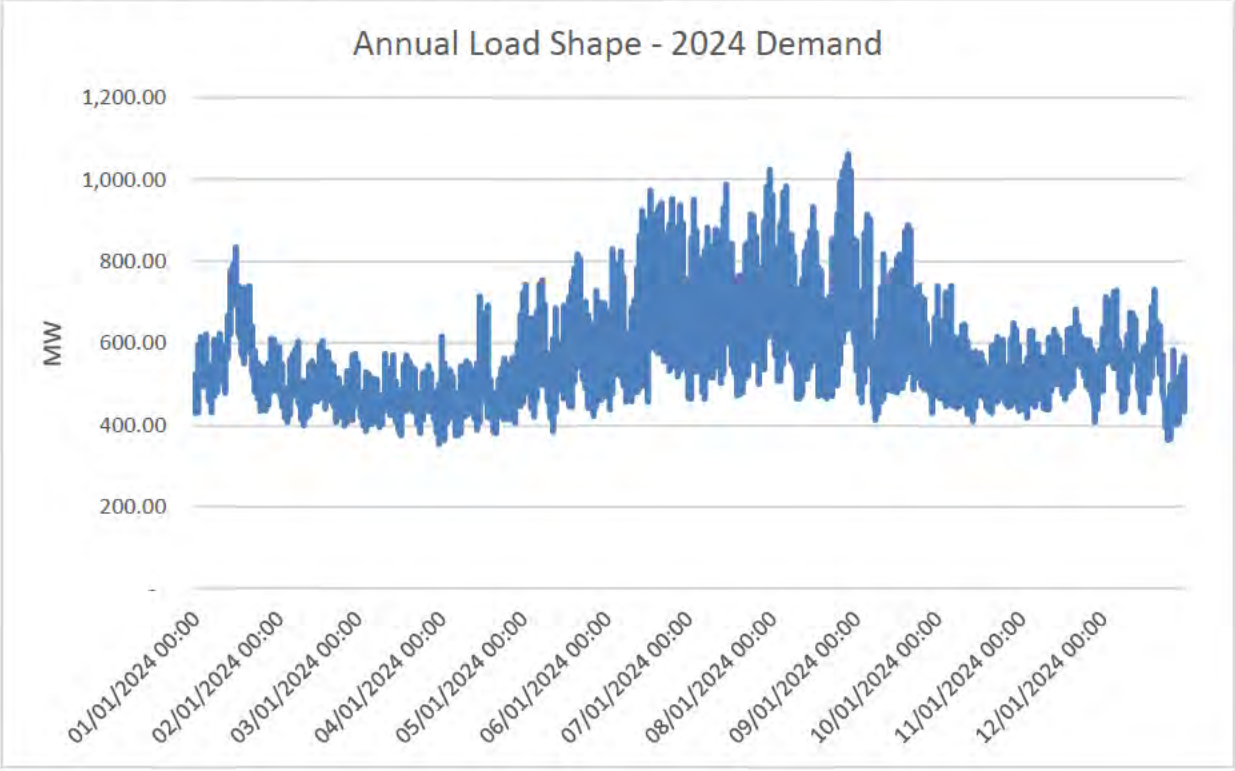


Figure 8-11- Summer Peak Day

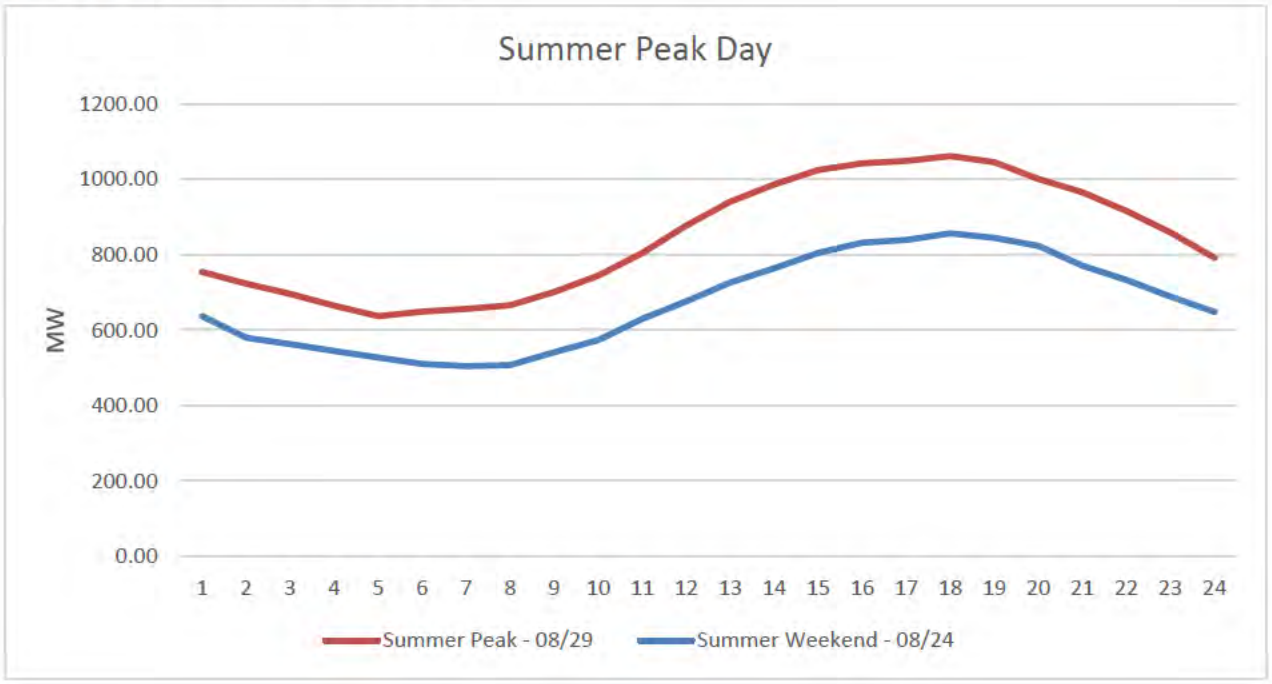


Figure 8-12- Typical Fall Day

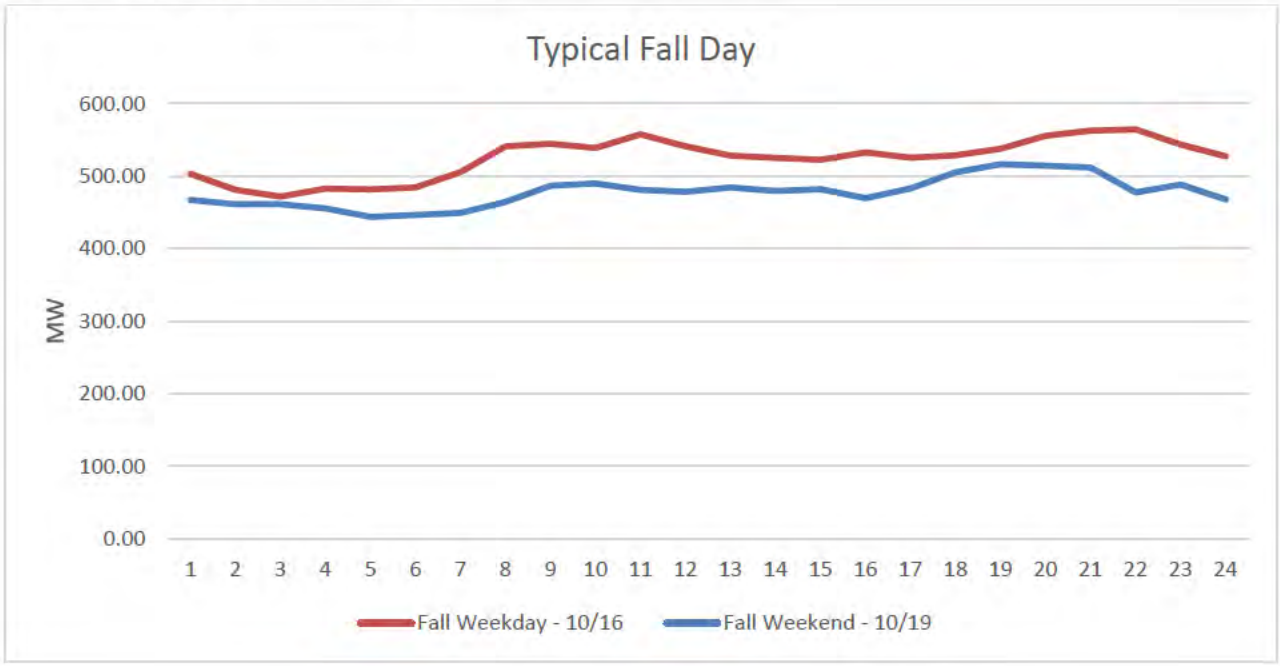


Figure 8-13- Winter Peak Day

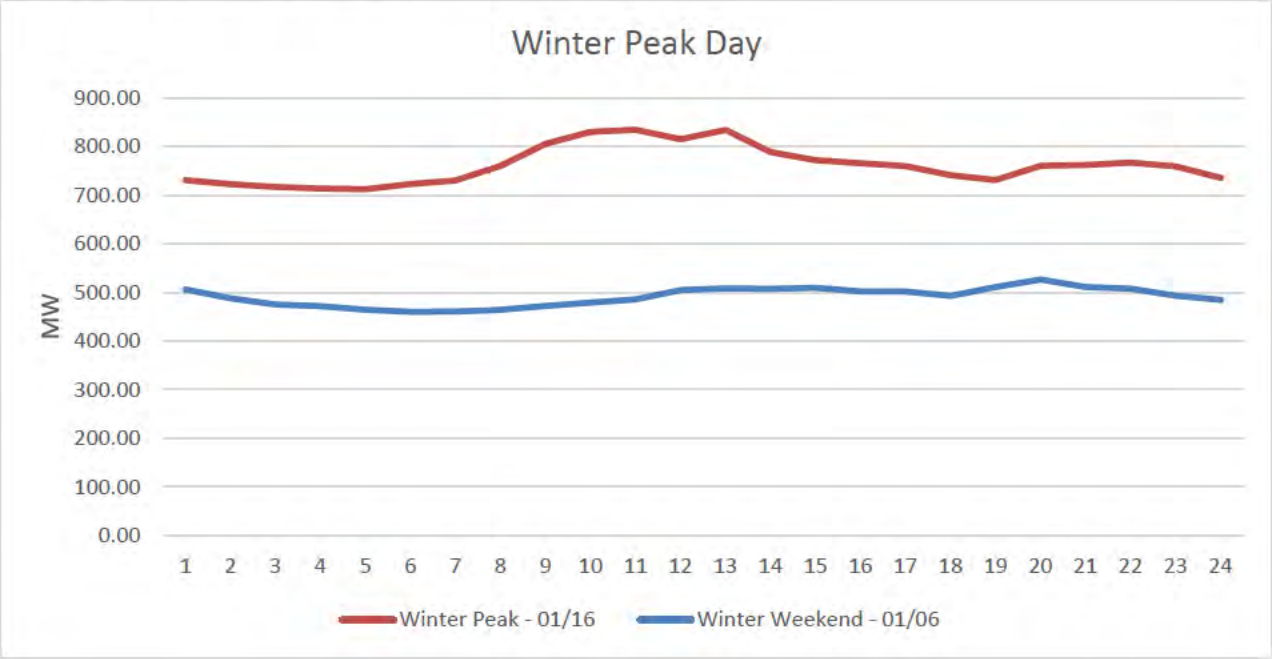


Figure 8-14- Typical Spring Day

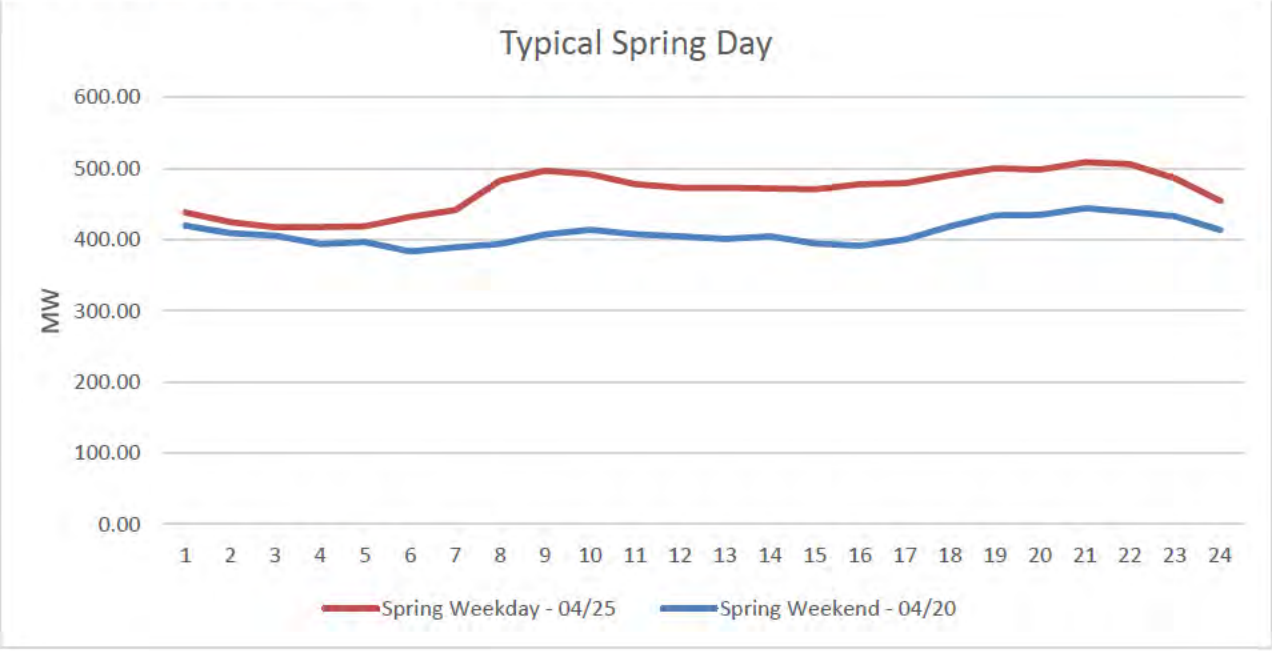


Figure 8-15- January Load



Figure 8-16- February Load

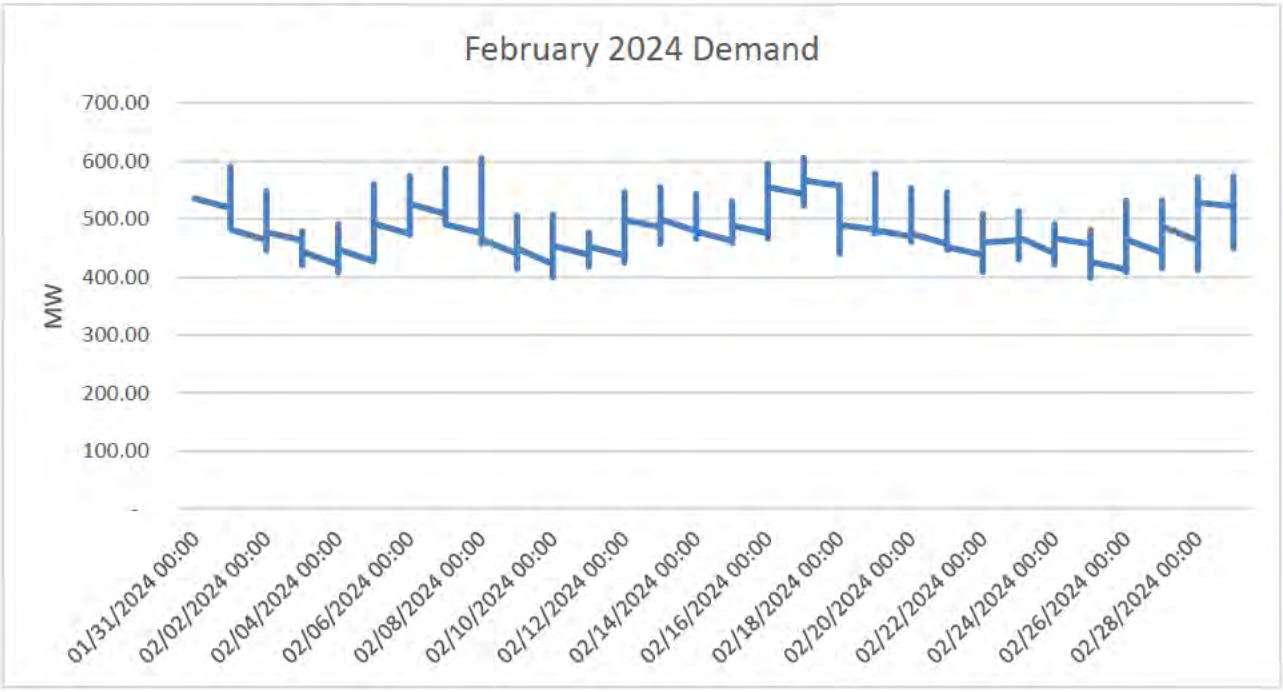


Figure 8-17- March Load

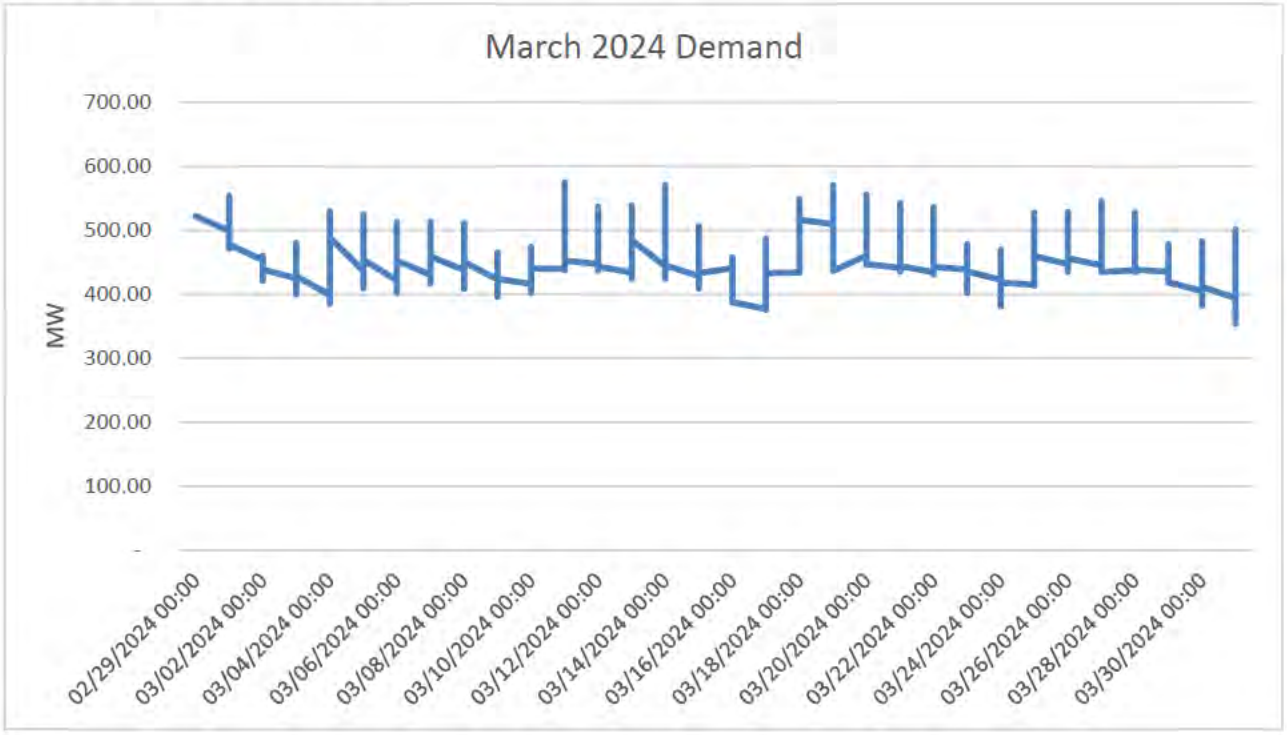


Figure 8-18- April Load

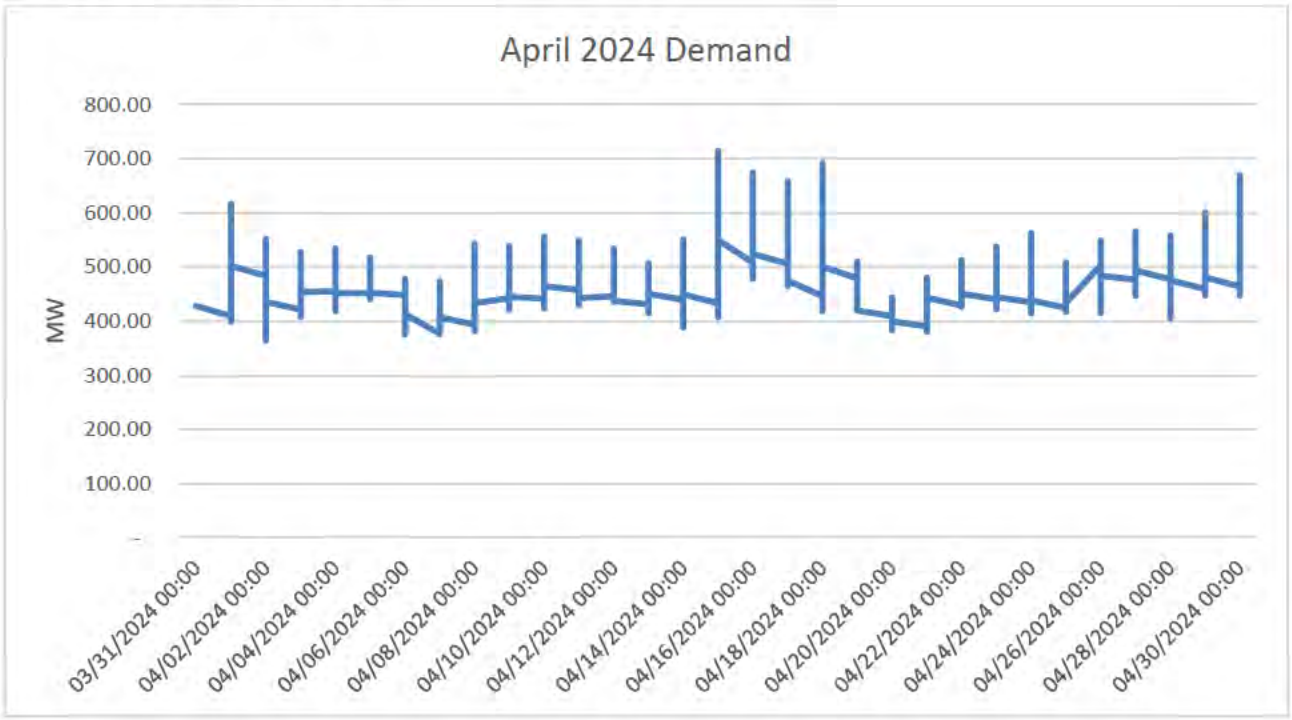


Figure 8-19- May Load

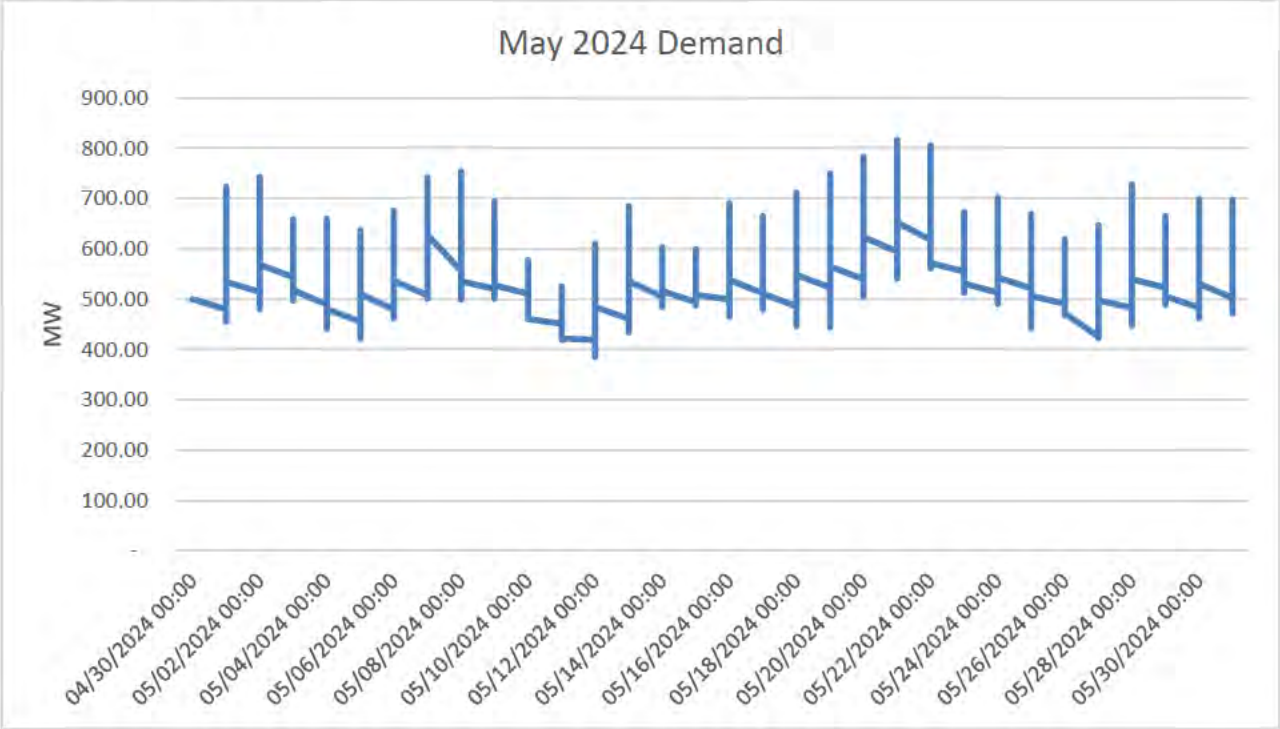


Figure 8-20- June Load

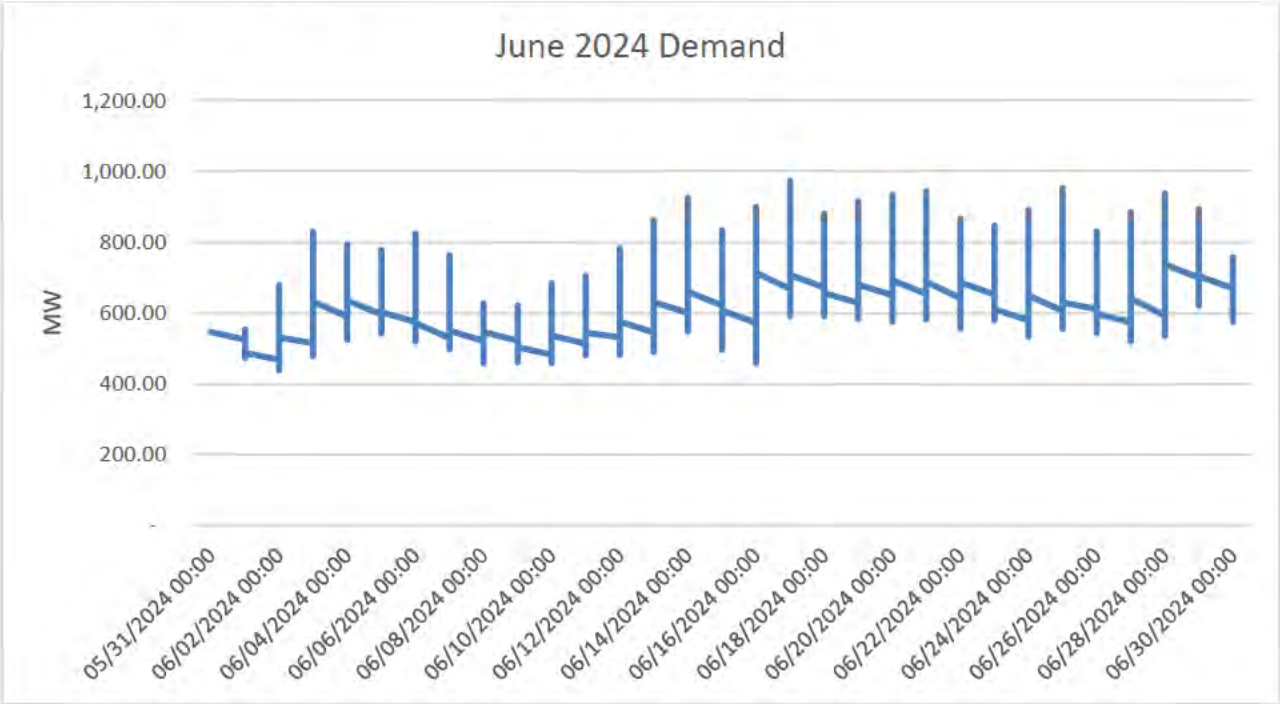


Figure 8-21- July Load

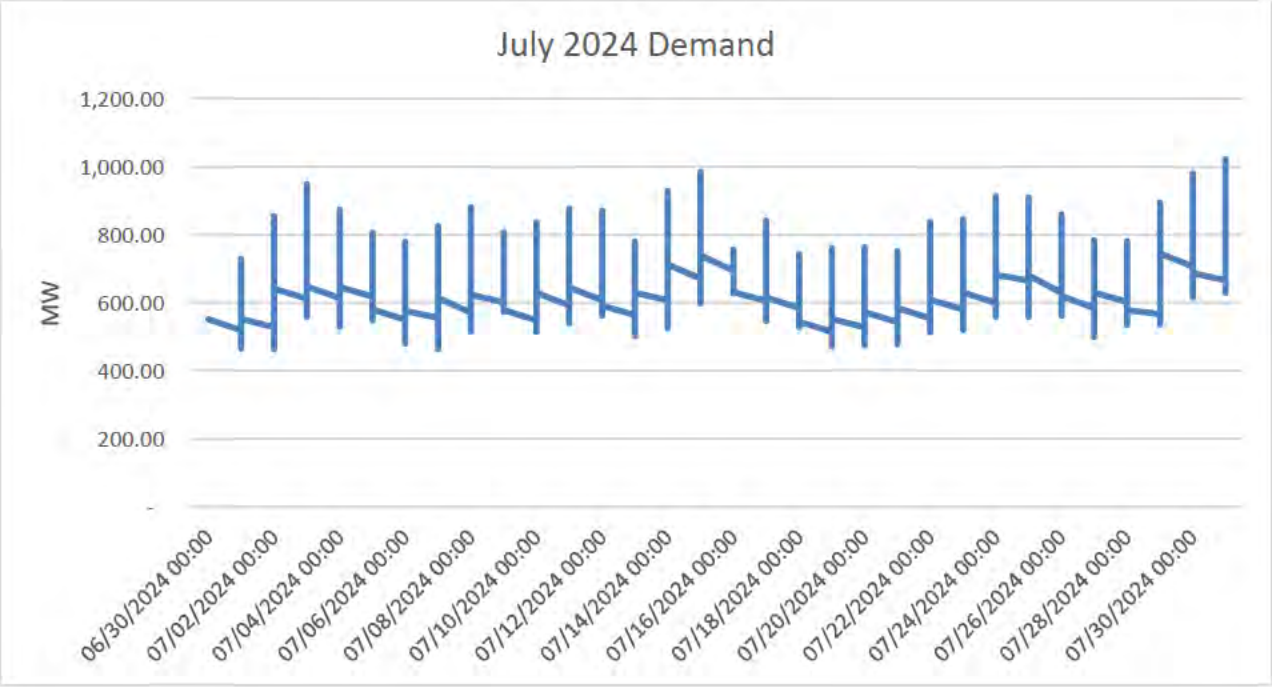


Figure 8-22- August Load

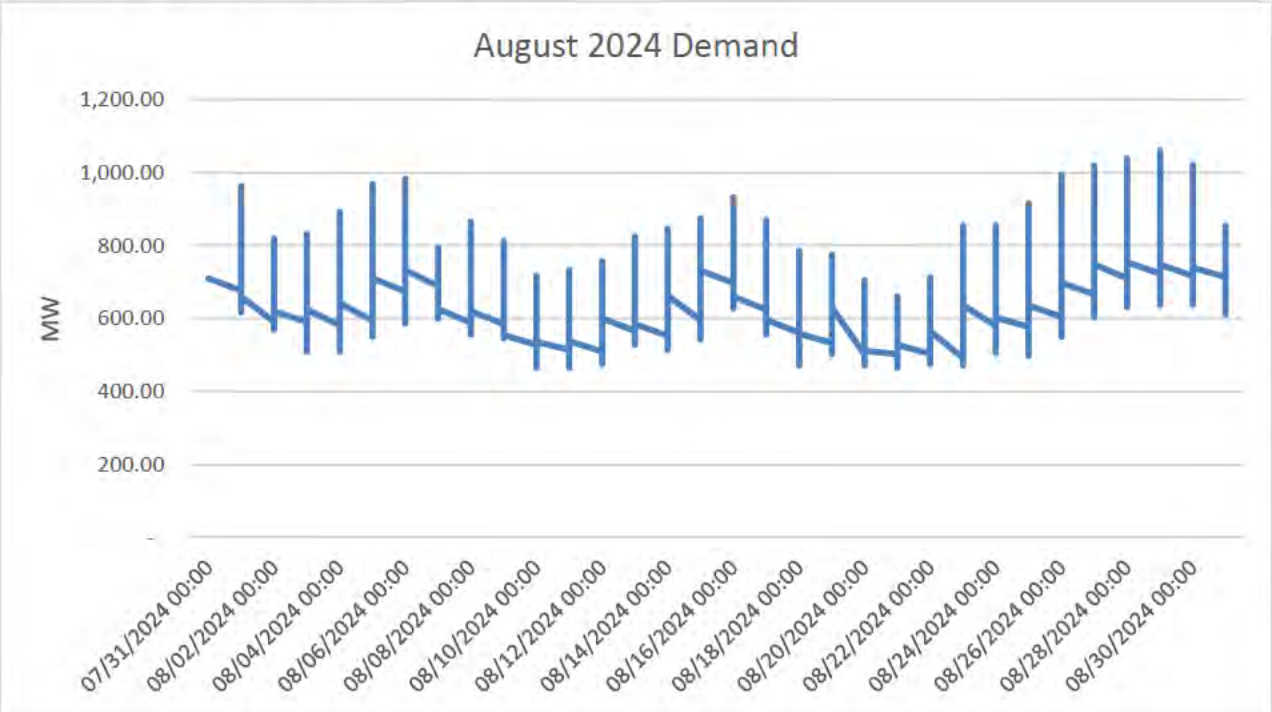


Figure 8-23- September Load

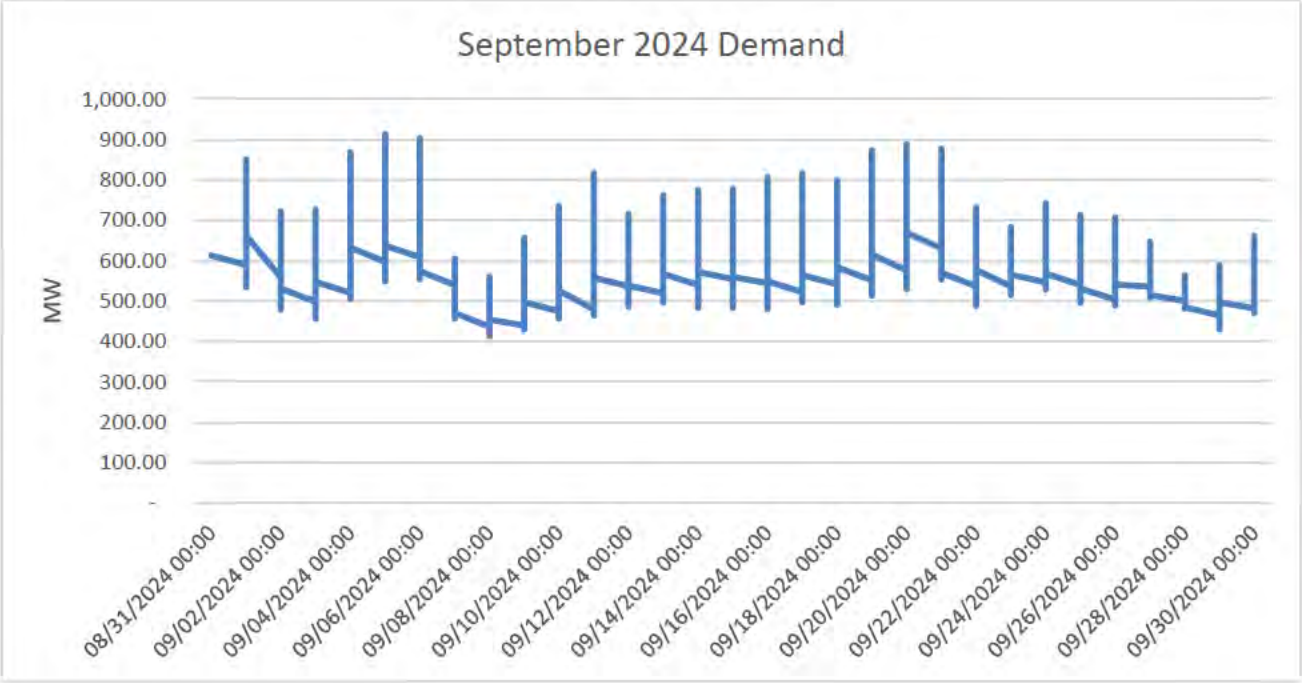


Figure 8-24- October Load

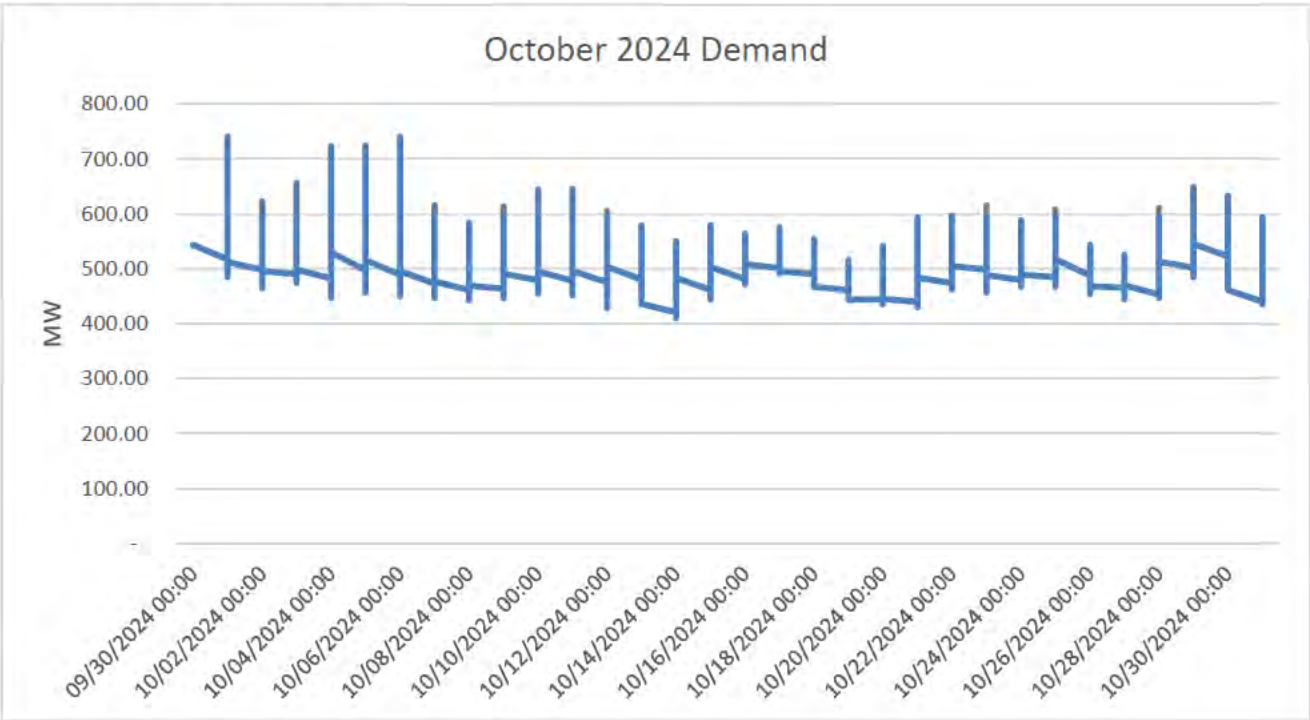


Figure 8-25- November Load

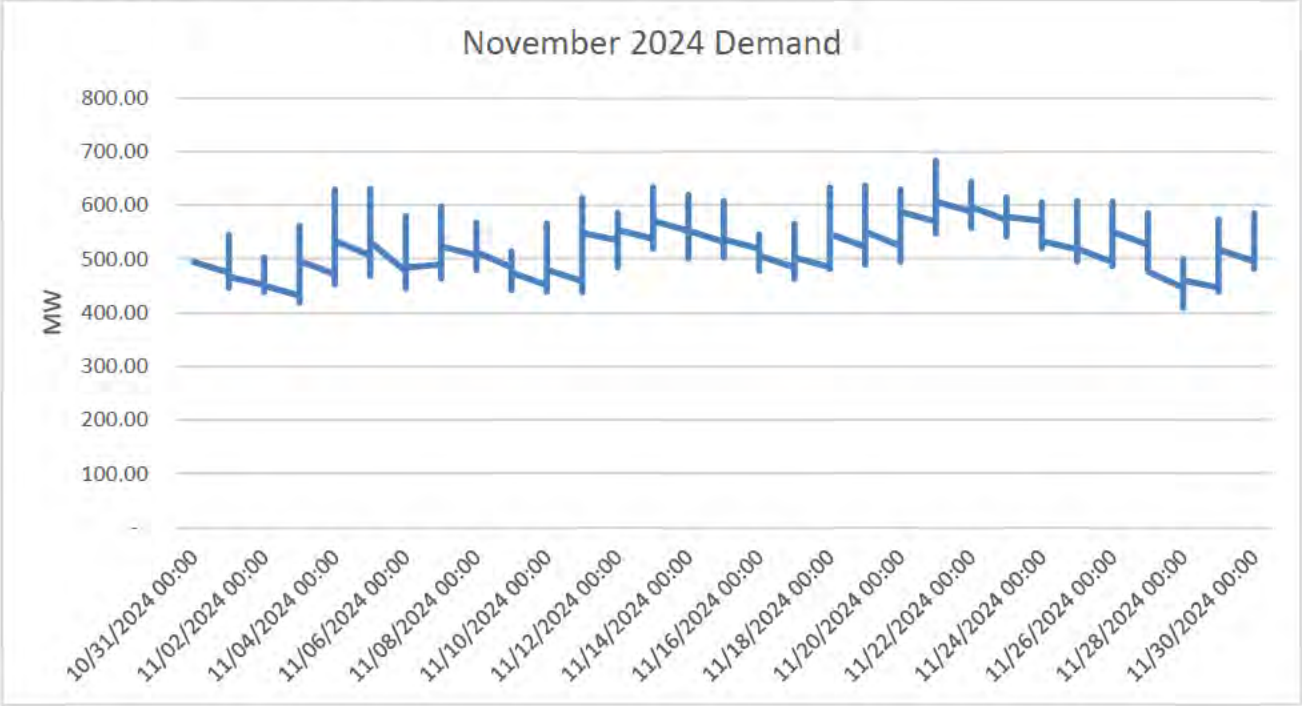


Figure 8-26- December Load



8.1.5. Advanced Metering Infrastructure and Continuous Improvement

CEI South has Advanced Metering Infrastructure (“AMI”). As described previously, the company continues to enhance the system with the use of edge computing applications that provide the company with valuable data to evaluate reliability and resiliency performance, and to find and correct items before they turn into issues that could affect customers. This information can be utilized to enhance forecasting and to perform more effective system planning and improved outage management resulting in better service and communications to customers. CEI South has been actively creating a system to help utilize AMI data for the CPP TOU rate. The pilot that is set to begin in Q2 2026, which has a time-based rate component and a demand response component, is enabled by the system that was put into place years ago. This program is intended to reduce system peak demand, mitigate capacity needs, and encourage cost efficient consumption behaviors. Incentivizing customers to lower consumption during the system’s most constrained hours reduces the need for peak generation resources and provides a mechanism to manage load during tight system conditions or during extreme weather events.

8.2. Environmental Appendix

8.2.1. Air Emissions

It was assumed that current or future generation resources would not exceed CEI South’s allocated annual SO_2 and NO_x emission allowances. CEI South’s fleet of existing power generation facilities meet all rules and regulations related to SO_2 and NO_x emissions, while the cost of emission control equipment and NO_x is factored into any new natural gas-fired facilities, or in the case of a natural gas conversion for Culley Unit 3, that would be selected as part of a portfolio. In 2023 EPA promulgated the Good Neighbor Plan which required 23 states, including Indiana, to further lower existing caps for seasonal NO_x allowances to be allocated to emissions units in the affected states and creating a CSAPR NO_x Ozone Season Group 3 Trading Program which would become effective in the 2024 ozone season. However, on June 27, 2024, the US Supreme Court granted emergency stay petitions, staying implementation of the rule. EPA issued guidance on August 5, 2024, reestablishing the existing CSAPR NO_x Ozone Season Group 2 allowance caps. Air emissions allowance costs are accounted for within IRP modeling.

8.2.2. Solid Waste Disposal

Fly ash from the F.B. Culley facility that meets beneficial reuse specifications is transported off site for beneficial reuse in a cement application, while fly ash that does not meet beneficial reuse specifications is transported for disposal in a permitted local landfill. The F.B. Culley facility completed the conversion of the Unit 3 bottom ash system to a dry

system in December 2020 and similarly sends bottom ash to beneficial reuse or transported for disposal in a permitted local landfill. The F.B. Culley facility utilizes a GeoTube Containment Area that collects the bottom ash and drains the filtrate to a lined pond. The collected bottom ash is sent for beneficial reuse or landfilled. Additionally, the F.B. Culley facility completed the construction of a Spray Dryer Evaporator to handle the FGD Wastewater from the scrubber. The East Ash Pond (approximately 10 acres) no longer receives any waste streams and is in final stages of closure. The West Pond (32 acres) completed closure in December 2020. The closure project included the construction of a new geosynthetic lined contact storm water pond that receives the coal pile run-off and other storm water that contacts industrial activity. Scrubber by-product generated by the F.B. Culley facility is sent off-site for beneficial reuse via shipment by river barge from F.B. Culley to a wallboard manufacturer.

8.2.3. Hazardous Waste

CEI South's A.B. Brown and F.B. Culley plants are episodic producers of hazardous waste that may include outage or maintenance related wastes, paints, parts washer fluids, or other excess or outdated chemicals. Both facilities are typically classified as Small Quantity Generators. All hazardous waste is disposed of in accordance with Federal and state regulations.

8.2.4. Water Consumption and Discharge

A.B. Brown and F.B. Culley currently discharge process and cooling water to the Ohio River under NPDES wastewater discharge permits issued by the IDEM. A.B. Brown natural gas fired combustion turbines have closed-loop cooling systems, while F.B. Culley has a once through cooling water system. In fall 2014, both plants installed chemical precipitation water treatment systems to meet Ohio River Valley Sanitation Commission ("ORSANCO") regional water quality standards mercury limit of 12 ppt monthly average.

8.3. DSM Appendix

8.3.1.1. DSM Planning Process

One of the key objectives of the IRP is to "provide all customers with a reliable supply of energy at the lowest reasonable cost." The level and costs of DSM to be offered in CEI South's service territory are important outcomes of the IRP process. The IRP will determine the appropriate level of DSM to include in the preferred resource plan. However, for CEI South, the IRP is not the appropriate tool to determine which specific programs to include in a DSM plan. Instead, every 3 years CEI South engages in a multi-step planning process designed to select programs that meet the level of savings established in the preferred resource portfolio. Once the level of DSM to be offered has been established by the IRP

and a portfolio of programs to meet the savings levels has been designed, the last step in the planning process is to re-affirm the cost effectiveness of the proposed programs.

8.3.1.2. Cost Benefit Analysis

Utilizing the DSMore cost/benefit model, the measures and programs were analyzed for cost effectiveness. The model includes a full range of economic perspectives typically used in EE and DSM analytics. Inputs into the model include the following: participation rates, incentives paid, energy and demand savings of the measure, life of the measure, avoided costs, implementation costs, administrative costs, incremental costs to the participant of the high efficiency measure and escalation rates and discount rates. CEI South considers the results of each test and ensures that the portfolio passes the Total Resource Cost test as it includes the total costs and benefits to both the energy company (program administrator) and the consumer. The outputs include all the California Standard Practice Manual results:

- Participant Cost Test
- Ratepayer Impact Measure Test
- Utility Cost Test (“UCT”)
- Total Resource Cost Test (“TRC”)

The cost effectiveness analysis produces two types of resulting metrics:

- Net Benefits (dollars) = NPV ∑ benefits – NPV ∑ costs
- Benefit Cost Ratio = NPV ∑ benefits ÷ NPV ∑ costs

The Participant Cost Test shows the value of the program from the perspective of the energy company’s customer participating in the program. The test compares the participant’s bill savings over the life of the DSM program to the participant’s cost of participation.

The Utility Cost Test shows the value of the program to the utility considering only avoided utility supply costs (based on the next unit of generation) in comparison to the utility program costs.

The Ratepayer Impact Measure (“RIM”) Test shows the impact of a program on all utility customers through impacts on average rates. This perspective also includes the estimates of revenue losses, which may be experienced by the utility as a result of the program.

The TRC Test shows the combined perspective of the energy company and the participating customers. This test compares (1) the level of benefits associated with the reduced energy supply costs to (2) the costs incurred by the energy company and by

program participants. In completing the tests listed above, CEI South used 6.77% as the weighted average cost of capital, which is the weighted cost of capital that was approved by the IURC on December 5, 2023 in Cause No. 45990.

Figure 8-27 - CEI South Cost Effectiveness Tests Benefits & Costs Summary

Test	Benefits	Costs
Participant Cost Test	• Incentive payments • Annual bill savings • Applicable tax credits	• Incremental technology/equipment costs • Incremental installation costs
Rate Impact Measure Test	• Avoided energy costs • Avoided capacity costs	• All program costs (startup, marketing, labor, evaluation, promotion, etc.) • Utility/Administrator incentive costs • Lost revenue due to reduced energy bills
Utility Cost Test (Program Administrator Cost Test)	• Avoided energy costs • Avoided capacity costs	• All program costs (startup, marketing, labor, evaluation, promotion, etc.) • Utility/Administrator incentive costs
Total Resource Cost Test	• Avoided energy costs • Avoided capacity costs • Applicable participant tax credits	• All program costs (not including incentive costs) • Incremental technology/equipment costs (whether paid by the participant or the utility)

8.3.2. Gross Savings 2025-2027 Plan

Figure 8-28 - 2025-2027 Approved Plan Gross kWh Energy Savings

	2025		2026		2027	
Sector	**Gross kWh Energy Savings**	**Gross KW Demand Savings**	**Gross kWh Energy Savings**	**Gross KW Demand Savings**	**Gross kWh Energy Savings**	**Gross KW Demand Savings**
Residential	14,377,963	8,184	15,932,490	9,214	15,862,630	8,236
C&I	22,600,000	3,005	25,024,327	3,492	25,400,000	3,279
Total	**36,977,963**	**11,189**	**40,956,817**	**12,706**	**41,262,630**	**11,515**

8.3.3. DSM Programs

CEI South has offered tariff-based DSM resource options to customers for many years. Consistent with a settlement approved in 2007 in Cause No. 43111, the Demand Side Management Adjustment ("DSMA") was created to specifically recover all CEI South's Commission approved DSM costs, including (at that time) a DLC Component. The Commission, in its order in Cause No. 43427, authorized CEI South to include both Core and Core-Plus DSM Program Costs and related incentives in an Energy Efficiency Funding Component ("EEFC") of the DSMA. The EEFC supports the Company's efforts to help customers reduce their consumption of electricity and related impacts on peak demand. It is designed to recover the costs of Commission-approved DSM programs from all customers receiving the benefit of these programs. In Cause Nos. 43427, 43938 and 44318, the Commission approved recovery of the cost of Conservation Programs via the EEFC. This rider is applicable to customers receiving service pursuant to Rate Schedules RS, B, SGS, DGS, MLA, OSS, LP and HLF.

8.3.4. Impacts

The table below demonstrates estimated energy (kWh) and demand (kW) savings per participant for each program.

Figure 8-29 - 2025 Electric DSM Operating Plan Program Savings

Program	Sector	Participants	NTG	Gross kWh	Gross kWh/Participant	Net kWh	Gross KW	Gross KW/Participant	Net KW
Residential Prescriptive	Residential	1,978	74%	474,041	240	350,980	195	0 099	144
Residential Midstream	Residential	1,783	47%	1,841,874	1,033	874,256	581	0 326	276
Home Energy Assessment	Residential	478	100%	377,520	790	377,520	27	0 056	27
In Store Discount	Residential	4,575	100%	457,893	100	457,893	36	0 008	36
Multi Family Energy Solutions	Residential	26	100%	369,015	14,193	369,015	25	0 969	25
Community Connections	Residential	44,864	100%	778,895	17	778,895	24	0 001	24
Residential New Construction	Residential	154	64%	78,637	511	50,609	30	0 197	19

Program	Sector	Participants	NTG	Gross kWh	Gross kWh/Participant	Net kWh	Gross KW	Gross KW/Participant	Net KW
Income Qualified Weatherization	Residential	837	100%	779,346	931	779,346	83	0 099	83
Marketplace	Residential	7,209	100%	1,618,571	225	1,618,571	603	0 084	603
Residential Behavioral Savings	Residential	49,700	100%	6,125,117	123	6,125,117	1,850	0 037	1,850
Smart Cycle (DLC Change Out)	Residential	3,000	100%	1,477,053	492	1,477,053	3,300	1 100	3,300
BYOT (Bring Your Own Thermostat)	Residential	1,300	100%	0	0	0	1,430	1 100	1,430
Commercial Prescriptive	Commercial	13,047	84%	10,751,737	824	9,031,459	1,709	0 131	1,435
Commercial Midstream	Commercial	32	84%	448,263	14,008	376,541	53	1 658	45
Commercial Custom	Commercial	89	84%	5,600,000	62,921	4,704,000	754	8 468	633
Small Business Energy Solutions	Commercial	13,873	84%	4,300,000	310	3,612,000	470	0 034	395
Building Optimization	Commercial	10	100%	1,500,000	150,000	1,500,000	20	2 000	20
DSM Portfolio Total		**142,955**	**88%**	**36,977,963**	**259**	**32,483,256**	**11,189**	**0.078**	**10,345**

Figure 8-30 - 2026 Electric DSM Proposed Operating Plan Program Savings

Program	Sector	Participants	NTG	Gross kWh	Gross kWh/Participant	Net kWh	Gross KW	Gross KW/Participant	Net KW
Residential Prescriptive	Residential	2,638	74%	427,293	162	314,238	166	0 063	122
Residential Midstream	Residential	2,642	48%	1,861,980	705	884,859	587	0 222	279
Home Energy Assessment	Residential	385	100%	473,865	1,231	473,865	35	0 091	35
In Store Discount	Residential	3,300	100%	532,856	161	532,856	40	0 012	40
Multi Family Energy Solutions	Residential	350	100%	369,015	1,054	369,015	25	0 072	25
Community Connections	Residential	28,040	100%	778,895	28	778,895	24	0 001	24
Residential New Construction	Residential	167	64%	78,637	471	50,609	30	0 181	19
Income Qualified Weatherization	Residential	800	100%	784,991	981	784,991	86	0 108	86
Marketplace	Residential	6,100	100%	1,694,556	278	1,694,556	632	0 104	632
Residential Behavioral Savings	Residential	62,000	100%	6,125,117	99	6,125,117	1,850	0 030	1,850
Smart Cycle (DLC Change Out)	Residential	2,500	100%	1,477,053	591	1,477,053	3,300	1 320	3,300
BYOT (Bring Your Own Thermostat)	Residential	1,800	100%	0	0	0	1,430	0 794	1,430
Commercial Prescriptive	Commercial	13,003	84%	12,032,995	925	10,107,640	1,883	0 145	1,582
Commercial Midstream	Commercial	38	84%	567,005	14,921	476,284	82	2 150	69
Commercial Custom	Commercial	93	84%	6,100,000	65,591	5,124,000	754	8 106	633
Small Business Energy Solutions	Commercial	13,873	84%	4,300,000	310	3,612,000	470	0 034	395
Building Optimization	Commercial	5	100%	1,500,000	300,000	1,500,000	20	4 000	20
DSM Portfolio Total		**143,646**	**88%**	**40,956,817**	**285**	**36,158,538**	**12,706**	**0.088**	**11,836**

Figure 8-31 - 2027 Electric DSM Approved Plan Program Savings

Program	Sector	Participants	NTG	Gross kWh	Gross kWh/Participant	Net kWh	Gross KW	Gross KW/Participant	Net KW
Residential Prescriptive	Residential	1,724	73%	395,946	230	287,817	141	0 082	103
Residential Midstream	Residential	1,793	48%	1,896,389	1,058	902,894	597	0 333	284
Home Energy Assessment	Residential	748	100%	570,893	763	570,893	44	0 058	44
In Store Discount	Residential	7,275	100%	607,820	84	607,820	43	0 006	43
Multi Family Energy Solutions	Residential	26	100%	369,015	14,193	369,015	25	0 969	25
Community Connections	Residential	44,864	100%	778,895	17	778,895	24	0 001	24
Residential New Construction	Residential	154	64%	78,637	511	50,609	30	0 197	19
Income Qualified Weatherization	Residential	907	100%	790,637	872	790,637	90	0 099	90
Marketplace	Residential	7,893	100%	1,772,227	225	1,772,227	661	0 084	661
Residential Behavioral Savings	Residential	49,700	100%	7,125,117	143	7,125,117	1,850	0 037	1,850
Smart Cycle (DLC Change Out)	Residential	3,000	100%	1,477,053	492	1,477,053	3,300	1 100	3,300
BYOT (Bring Your Own Thermostat)	Residential	1,300	100%	0	0	0	1,430	1 100	1,430
Commercial Prescriptive	Commercial	12,958	84%	12,824,803	990	10,767,584	1,964	0 152	1,649
Commercial Midstream	Commercial	33	84%	675,197	20,461	567,166	72	2 170	60
Commercial Custom	Commercial	93	84%	6,100,000	65,591	5,124,000	754	8 106	633
Small Business Energy Solutions	Commercial	13,873	84%	4,300,000	310	3,612,000	470	0 034	395
Building Optimization	Commercial	10	100%	1,500,000	150,000	1,500,000	20	2 000	20
DSM Portfolio Total		**146,351**	**88%**	**41,262,630**	**282**	**36,303,727**	**11,515**	**0.079**	**10,631**

8.3.5. Avoided Costs

The avoided power capacity costs are reflective of the estimated replacement capital and fixed Operations and Maintenance ("O&M") cost. For this avoided cost analysis, a 235 MW 1x F-class simple cycle gas turbine was used as the comparison due to the low capital and fixed O&M costs. The operating and capital costs are assumed to escalate with inflation throughout the study period. Transmission and distribution capacity are accounted for within the transmission and distribution avoided cost.

The marginal operating energy costs were based off the modeled CEI South system marginal energy cost from the Preferred Portfolio under Reference Case assumptions. This included estimated capital, variable operation and maintenance and fuel costs. The marginal system cost reflects the modeled spinning reserve requirement and adjusted sales forecasts accounting for transmission and distribution losses.

The table below (Figure 8-32) shows avoided costs when energy efficiency is selected through the IRP modeling process. As energy efficiency competes against other supply side resources and is selected, then the cost of a 235 MW 1x F-class simple cycle gas turbine is avoided.

Figure 8-32 - Avoided Costs

Year	Avoided Capital/ O&M Cost ($/kW)	Transmission & Distribution Avoided Capital Cost ($/kW)	Total Capacity Avoided Cost ($/kW)	Natural Gas Forecast ($/MMBtu)	System Marginal Cost ($/MWh)
2026	$180.11	$13.74	**$193.85**	$3.48	$44.65
2027	$183.95	$13.58	**$197.53**	$3.76	$45.97
2028	$187.87	$13.72	**$201.59**	$4.08	$49.69
2029	$191.87	$14.16	**$206.03**	$4.39	$55.71
2030	$195.95	$14.62	**$210.57**	$4.62	$54.37
2031	$200.13	$14.30	**$214.42**	$4.82	$56.65
2032	20439%	$14.70	**$219.09**	$4.91	$57.73
2033	$208.74	$14.93	**$223.67**	$4.99	$59.41
2034	$213.19	$15.21	**$228.40**	$5.14	$48.46
2035	$217.73	$15.71	**$233.44**	$5.31	$58.75
2036	$222.37	$15.94	**$238.31**	$5.45	$60.34
2037	$227.11	$16.29	**$243.40**	$5.57	$60.95
2038	$231.94	$16.63	**$248.57**	$5.74	$62.16
2039	$236.88	$16.99	**$253.87**	$5.92	$63.85
2040	$241.93	$17.37	**$259.30**	$6.22	$66.94
2041	$247.08	$17.72	**$264.80**	$6.37	$66.63
2042	$252.34	$18.10	**$270.45**	$6.58	$66.70
2043	$257.72	$18.49	**$276.21**	$6.77	$69.91
2044	$263.21	$18.88	**$282.09**	$7.00	$70.70
2045	$268.82	$19.29	**$288.10**	$7.33	$69.87

8.3.6. Estimated Impact on Historical Forecasted Peak Demand and Energy

The load forecast developed by Itron incorporates CEI South's historical DSM in the residential and commercial models to account for historical program savings. The DSM variables help explain historical usage trends. For additional details on the impact of DSM on the forecast see *Technical Appendix Attachment 3.12025 CEIS Long-Term Electric Energy & Demand Forecast Report, Section 5.4 Historical DSM Savings*.

8.3.7. Appliance Saturation Survey

CEI South conducted a residential energy efficiency baseline survey which launched on February 17, 2025 and was closed on February 28, 2025. CEI South fielded forty-seven

(47) questions, which were developed with input from GDS (CEI South's Market Potential Study vendor), Itron, and the OSB. The survey contained a set of core questions with an option for customers to answer additional questions. CEI had 1,048 people who started the survey and 730 who completed the entire survey for a response rate of 5.4% out of the total number of people who received the survey. Survey responses informed the market potential study both qualitative, and quantitative in terms of saturation and efficiency levels of measures. The 2025 CNP Residential Energy Efficiency Baseline Survey presentation can be found in *Technical Appendix Attachment 3.7*. The results of the 2025 Survey will be incorporated into the sales and demand forecasts in future IRPs.

8.4. Risk Appendix

The probabilistic risk assessment allows for the development of portfolio results based on a range of randomly sampled input values. Specifically, it evaluates uncertainty around coal, natural gas, CO_2, and MISO energy prices, peak load, capital costs for new renewable, thermal, and storage resources, and market energy sales. With the uncertainty around the variables defined by probability distributions, the variables were modeled stochastically using Encompass's Monte Carlo sampling capability. Stochastically developed inputs allow for the testing of each portfolio's performance across a wide range of probable market conditions. The development of probability distributions around uncertainty variables, combined with running these distributions through a stochastic process to develop 200 sets of inputs, is key to the probability risk assessment approach. The probability distributions used in the assessment are described in more detail below.

8.4.1. Stochastics (Probabilistic Modeling)

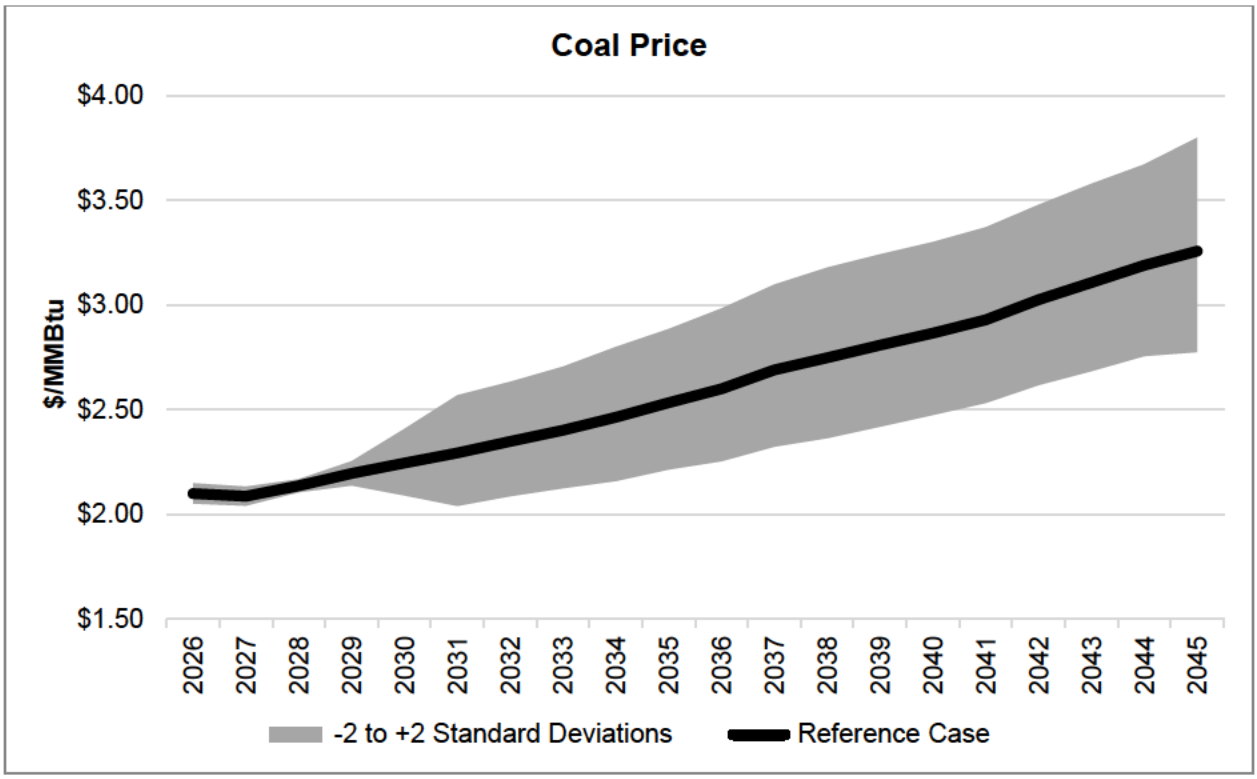
To perform the stochastics (probabilistic modeling), a set of probability distributions that characterize uncertainty was required for each of the key variables described above (coal prices, natural gas prices, MISO energy prices, peak demand, CO_2 prices, capital costs for new resources, and market sales). Monthly lognormal probability distributions were assumed for coal prices, natural gas prices, and peak demand. For the other variables, discrete distributions were developed at varying time intervals: hourly for MISO energy prices, monthly for sales limits, and annually for CO_2 prices and new resource capital costs. The lognormal probability distributions were stochastically simulated together in EnCompass with cross-variable correlation using Monte Carlo Sampling. This produced 200 sets of correlated inputs for coal prices, natural gas prices and peak demand. These stochastic runs in EnCompass assumed 100 percent mean reversion. The discrete distributions for MISO energy prices, CO_2 prices, new resource capital costs, and sales limits were then randomly assigned to each of the 200 stochastic iterations. These input sets were individually run through the dispatch model in EnCompass with each of 12

selected portfolios for a total of 2,400 simulations. The following sections describe the methodologies for developing the stochastic variables.

8.4.1.1. Coal Price Uncertainty

To define the uncertainty around coal prices to be used in the stochastic modeling, 1898 & Co. relied on a base, high and low coal price forecast from U.S. Energy Information Administration's ("EIA") 2025 Annual Energy Outlook ("AEO"). Specifically, 1898 & Co. developed annual standard deviations based on the EIA's Interior Minemouth price forecasts for the Reference Case, High Oil Price Case, and the Alternative Electricity Case. These annual standard deviations were converted to monthly standard deviations, which were then divided by EIA Interior Minemouth Reference Case pricing to arrive at percent standard deviations for coal pricing. The monthly percent standard deviations were then applied to the IRP consensus Reference Case pricing to impute a monthly lognormal probability distribution for coal pricing. These monthly distributions of coal prices were in turn sampled in the stochastic modeling that developed the 200 sets of stochastic inputs. Figure 8-33 displays the base coal forecast as well as two standard deviations from the mean.

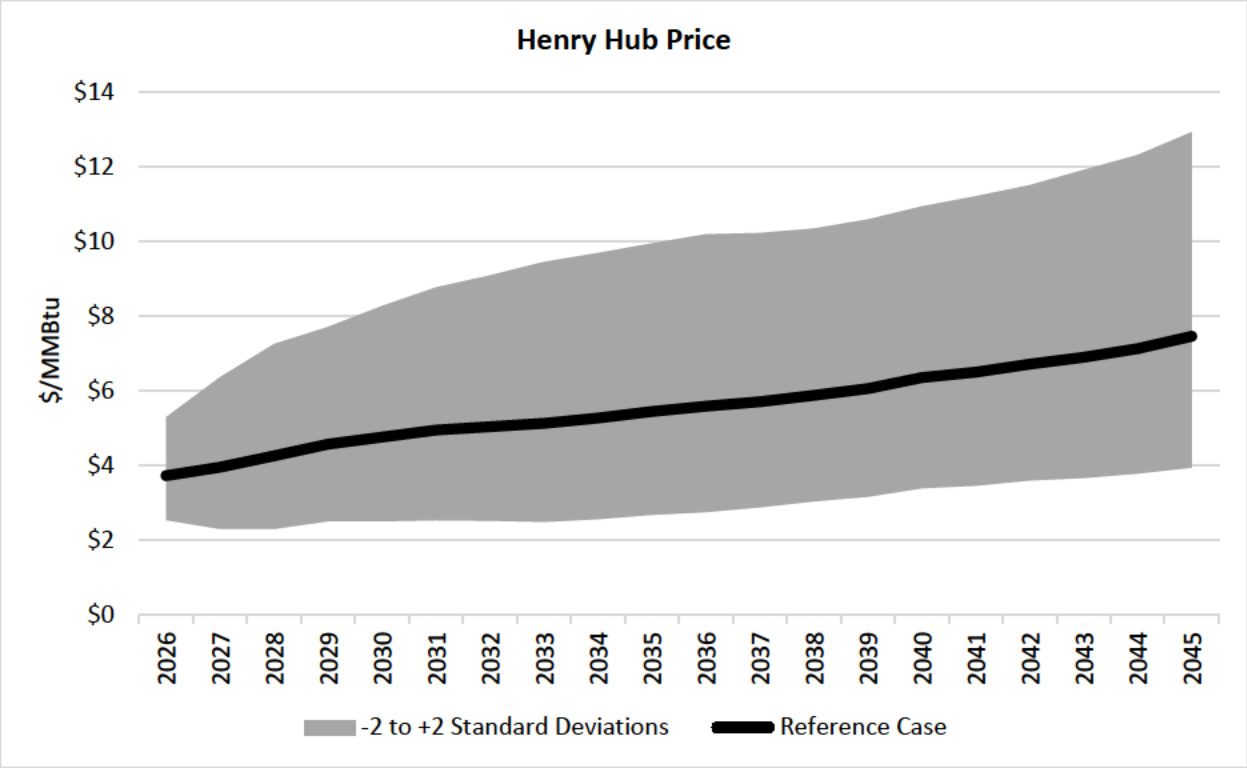
Figure 8-33 - Coal Price Distribution (Nominal$/MMBtu)



8.4.1.2. Natural Gas Price Uncertainty

To define the uncertainty around natural gas prices to be used in the stochastic modeling, 1898 & Co. relied on the base, high and low Henry Hub natural gas price forecast using data from Hitachi (ABB). Specifically, 1898 & Co. developed monthly standard deviations from the base, high and low forecasts, divided the result by the base price forecast to arrive at a percent standard deviation. The monthly percent standard deviations were then applied to the consensus Reference Case pricing to impute a monthly lognormal probability distribution for natural gas pricing. These monthly natural gas price distributions were in turn sampled in the stochastic modeling that developed the 200 sets of stochastic inputs. An illustration of the Reference Case natural gas forecast as well as its uncertainty is given in Figure 8-34.

Figure 8-34 - Natural Gas (Henry Hub) Price Distribution (Nominal$/MMBtu)

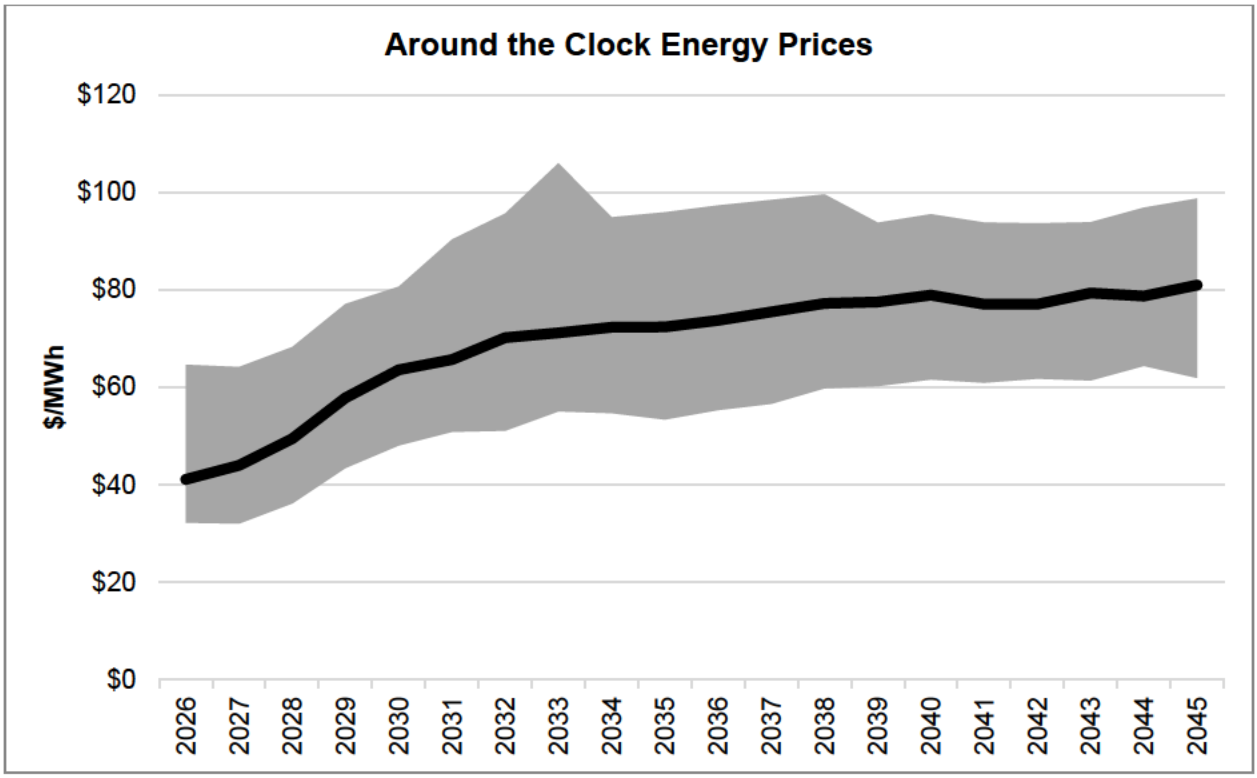


8.4.1.3. Energy Price Distribution

1898 & Co. updated energy prices that were input into EnCompass for each of the 200 draws. 1898 & Co. used the national database licensed from Horizon Energy, LLC as the starting point for creating the energy prices. Using the different IRP scenarios, unique energy price forecasts were developed. The energy prices and associated natural gas prices from the scenario model runs were used to develop monthly implied market heat

rate curves. These monthly implied market heat rates were applied to the monthly natural gas price for the 200 iterations to arrive at monthly energy prices for each iteration.

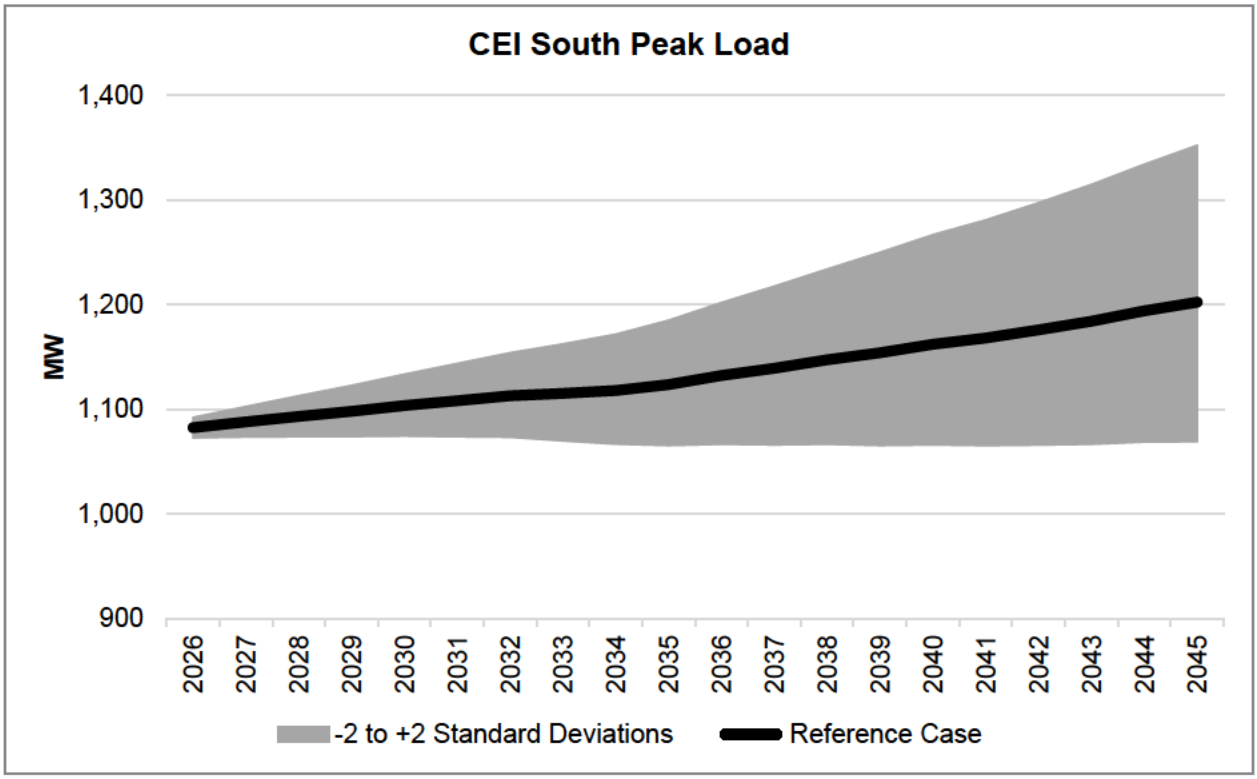
Figure 8-35 - Stochastic Inputs Energy Prices – Market Forecast



8.4.1.4. Load Uncertainty

To account for electricity demand variability that derives from economic growth, weather, energy efficiency and demand side management measures, 1898 & Co. relied on monthly peak load forecasts developed by CEI South's vendor, Itron. Itron developed base high and low peak demand forecasts. Using these forecasts, 1898 & Co. calculated monthly peak demand standard deviations which were applied to a lognormal distribution to represent the probability of monthly peak demand within the stochastic modeling framework. Figure 8-36 below shows uncertainty around peak loads.

Figure 8-36 - CEI South Load Distribution (Megawatts)



8.4.1.5. CO_2 Emissions Price Uncertainty

No CO_2 emissions prices are assumed for the Reference Case, rather CO_2 prices are assumed for the High Regulatory scenario. Because of these assumptions, CO_2 price uncertainty is assigned on a discrete basis. Specifically, 1898 & Co. randomly assigned a zero price for CO_2 for 150 iterations out of the 200 iterations of stochastic inputs and the CO_2 price from the High Regulatory scenario for 50 iterations.

8.4.1.6. Capital Cost Uncertainty

1898 & Co. developed base, high, and low capital cost assumptions for renewable, thermal, and storage resources used in the scenario analyses. For technologies that had a purchase option submitted to the 2024 All-Source RFP – namely storage, solar and solar plus storage – the base forecast was developed using the average purchase price for received bids. For wind resources, the technology assessment was combined with data collected for wind Power Purchase Agreements ("PPA") received during the 2024 All Source RFP to create an estimate that reflected current market conditions. The proposals reflect current near-term purchase options and were forecasted through the study period using capital cost estimates from the NREL. The low forecast follows a similar methodology; however, it uses

the lowest received purchase price as a starting point and then trends linearly to the NREL reference case cost in 2045. In contrast, the high forecast begins with the highest bid price and then escalates throughout the study period at the assumed inflation rate (2.13%).

For technologies that did not have a purchase option submitted in the recent RFP, the technology assessment provided a starting point for cost estimates. Specifically, for nuclear and thermal technologies, the technology assessment cost estimate was used for a starting price, which was then forecasted to follow the moderate NREL curve. The low forecast follows the same methodology, starting at the technology assessment data point and then following the low NREL cost curve. Finally, the high forecast begins at the same point and then escalates through the study period at the assumed escalation rate.

Since the base, high and low capital costs were developed based on fundamental assumptions and do not conform to a specific probability distribution type, the costs were treated as discrete distributions and assigned to the 200 iterations for inclusion in the stochastic inputs. Low capital costs were assigned to the first 50 stochastic iterations, base (Reference Case) capital costs to the next 100, and high capital costs to the final 50 iterations. Because it is unlikely capital costs would stay high or low for every year of the study period, the order of iterations was randomly shuffled every four years prior to the 50/100/50 iteration assignments. With this approach, any one iteration would have a combination of base, high and low capital costs in four year segments.

The following figures provide examples of capital cost curves from each resource category. Note that these diagrams are provided without the adder for Allowance for Funds Used During Construction (“AFUDC”), which was applied to the capital costs seen in the EnCompass Model.

Figure 8-37 - Lithium-Ion 100 MW/400 MWh Battery Storage Capital Costs Alternate Scenarios ($/kW)

Year	Reference Case	Low	High	NREL
2026	$2,273	$1,955	$2,591	$1,805
2027	$2,273	$1,955	$2,591	$1,786
2028	$2,273	$1,955	$2,591	$1,765
2029	$2,244	$1,948	$2,646	$1,742
2030	$2,212	$1,942	$2,703	$1,718
2031	$2,227	$1,936	$2,760	$1,729
2032	$2,241	$1,930	$2,819	$1,740
2033	$2,255	$1,924	$2,879	$1,751
2034	$2,269	$1,918	$2,940	$1,762
2035	$2,282	$1,912	$3,003	$1,772
2036	$2,294	$1,905	$3,067	$1,782
2037	$2,307	$1,899	$3,132	$1,791
2038	$2,318	$1,893	$3,199	$1,800
2039	$2,329	$1,887	$3,267	$1,809
2040	$2,340	$1,881	$3,336	$1,817
2041	$2,350	$1,875	$3,407	$1,825
2042	$2,359	$1,869	$3,480	$1,832
2043	$2,367	$1,862	$3,554	$1,838
2044	$2,375	$1,856	$3,630	$1,845
2045	$2,382	$1,850	$3,707	$1,850

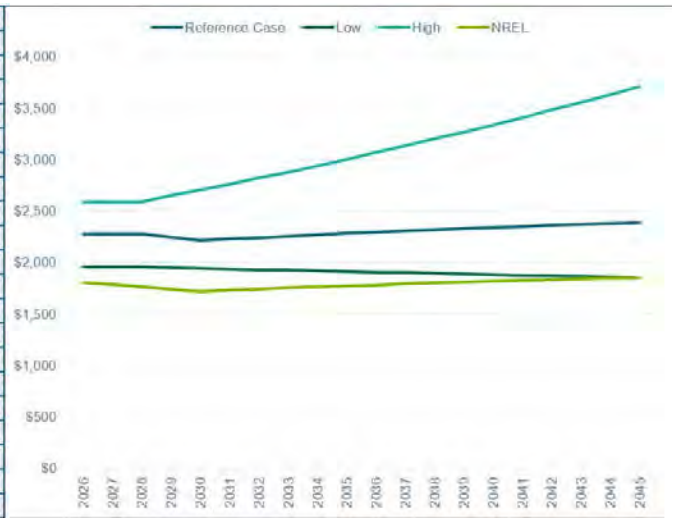


Figure 8-38 - Solar Capital Costs Alternate Scenarios (100 MW) ($/kW)

Year	Reference Case	Low	High	NREL
2026	$2,351	$1,895	$2,750	$1,558
2027	$2,351	$1,895	$2,750	$1,525
2028	$2,351	$1,895	$2,750	$1,490
2029	$2,351	$1,895	$2,750	$1,452
2030	$2,287	$1,853	$2,809	$1,413
2031	$2,219	$1,811	$2,868	$1,371
2032	$2,147	$1,769	$2,929	$1,326
2033	$2,071	$1,727	$2,992	$1,279
2034	$1,991	$1,685	$3,056	$1,230
2035	$1,906	$1,643	$3,121	$1,177
2036	$1,916	$1,601	$3,187	$1,183
2037	$1,925	$1,559	$3,255	$1,189
2038	$1,934	$1,517	$3,324	$1,195
2039	$1,943	$1,475	$3,395	$1,200
2040	$1,950	$1,433	$3,467	$1,205
2041	$1,958	$1,391	$3,541	$1,209
2042	$1,965	$1,350	$3,616	$1,213
2043	$1,971	$1,308	$3,693	$1,217
2044	$1,976	$1,266	$3,772	$1,221
2045	$1,981	$1,224	$3,852	$1,224

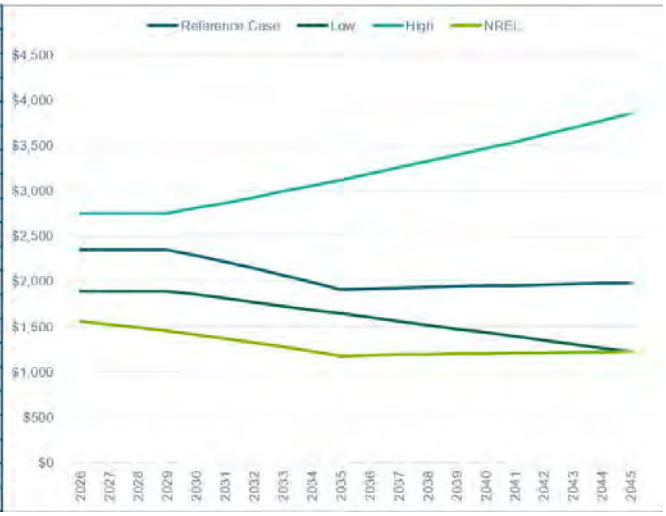


Figure 8-39 – Solar plus Storage Capital Costs Alternate Scenarios (100 + 50 MW) ($/kW)

Year	Reference Case	Low	High	NREL
2026	$3,492	$2,722	$4,500	$2,384
2027	$3,492	$2,722	$4,500	$2,342
2028	$3,492	$2,722	$4,500	$2,296
2029	$3,492	$2,722	$4,500	$2,248
2030	$3,412	$2,681	$4,596	$2,196
2031	$3,359	$2,641	$4,694	$2,163
2032	$3,303	$2,600	$4,794	$2,126
2033	$3,243	$2,559	$4,896	$2,088
2034	$3,178	$2,519	$5,000	$2,046
2035	$3,110	$2,478	$5,106	$2,002
2036	$3,125	$2,438	$5,215	$2,012
2037	$3,139	$2,397	$5,326	$2,021
2038	$3,152	$2,357	$5,440	$2,029
2039	$3,165	$2,316	$5,555	$2,037
2040	$3,176	$2,276	$5,674	$2,045
2041	$3,187	$2,235	$5,794	$2,052
2042	$3,197	$2,194	$5,918	$2,058
2043	$3,206	$2,154	$6,044	$2,064
2044	$3,213	$2,113	$6,173	$2,069
2045	$3,220	$2,073	$6,304	$2,073

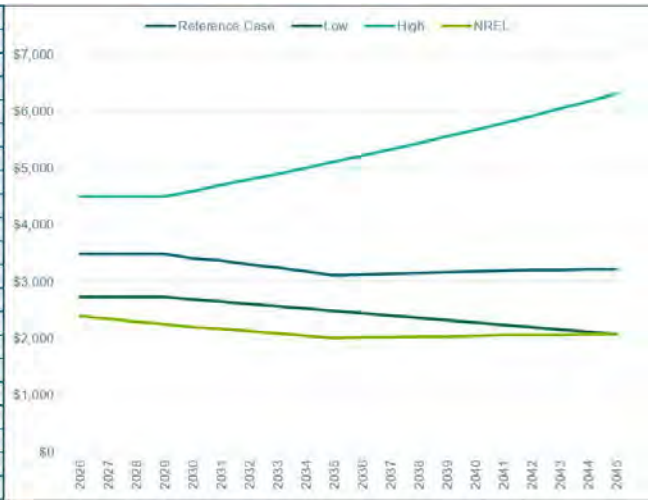


Figure 8-40 – Wind Capital Costs Alternate Scenarios (200 MW) ($/kW)

Year	Reference Case	Low	High	NREL
2026	$2,195	$1,625	$2,611	$1,672
2027	$2,195	$1,641	$2,667	$1,672
2028	$2,193	$1,657	$2,724	$1,671
2029	$2,191	$1,673	$2,782	$1,669
2030	$2,188	$1,689	$2,841	$1,666
2031	$2,211	$1,705	$2,902	$1,684
2032	$2,234	$1,721	$2,963	$1,702
2033	$2,258	$1,737	$3,026	$1,720
2034	$2,281	$1,753	$3,091	$1,737
2035	$2,304	$1,769	$3,157	$1,755
2036	$2,327	$1,785	$3,224	$1,773
2037	$2,351	$1,801	$3,292	$1,791
2038	$2,374	$1,817	$3,363	$1,808
2039	$2,397	$1,833	$3,434	$1,826
2040	$2,420	$1,849	$3,507	$1,843
2041	$2,442	$1,865	$3,582	$1,861
2042	$2,465	$1,881	$3,658	$1,878
2043	$2,488	$1,897	$3,736	$1,895
2044	$2,510	$1,913	$3,816	$1,912
2045	$2,532	$1,929	$3,897	$1,929

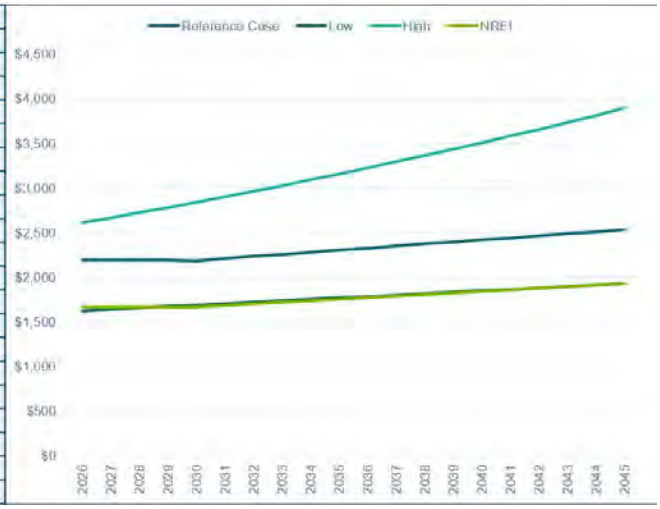


Figure 8-41 – 1x1 J Class Unfired CCGT Capital Costs Alternate Scenarios (620 MW) ($/kW)

Year	Reference Case	Low	High	NREL
2026	$2,065	$2,061	$2,082	$1,579
2027	$2,092	$2,083	$2,127	$1,599
2028	$2,119	$2,106	$2,172	$1,620
2029	$2,146	$2,128	$2,218	$1,640
2030	$2,173	$2,151	$2,266	$1,661
2031	$2,200	$2,173	$2,314	$1,682
2032	$2,228	$2,195	$2,363	$1,703
2033	$2,255	$2,217	$2,413	$1,724
2034	$2,283	$2,239	$2,465	$1,745
2035	$2,311	$2,262	$2,517	$1,767
2036	$2,342	$2,290	$2,571	$1,791
2037	$2,374	$2,319	$2,626	$1,815
2038	$2,406	$2,348	$2,681	$1,839
2039	$2,438	$2,377	$2,739	$1,864
2040	$2,471	$2,407	$2,797	$1,889
2041	$2,503	$2,436	$2,856	$1,914
2042	$2,536	$2,466	$2,917	$1,939
2043	$2,570	$2,496	$2,979	$1,964
2044	$2,603	$2,526	$3,043	$1,990
2045	$2,637	$2,556	$3,108	$2,016

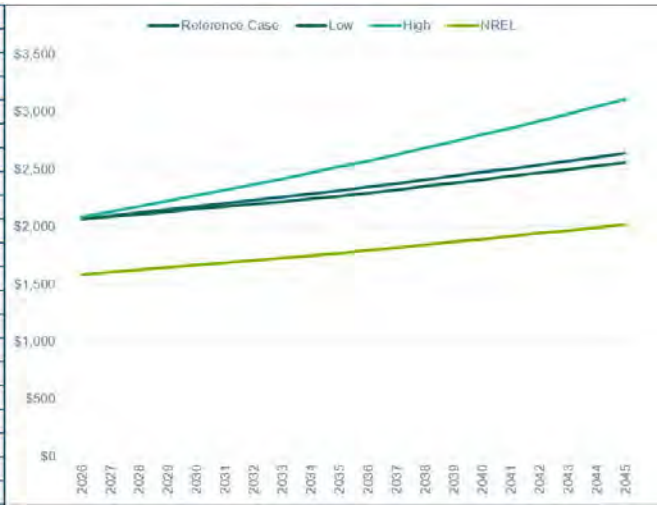


Figure 8-42 – J Class SCGT Capital Costs Alternate Scenarios (426 MW) ($/kW)[42]

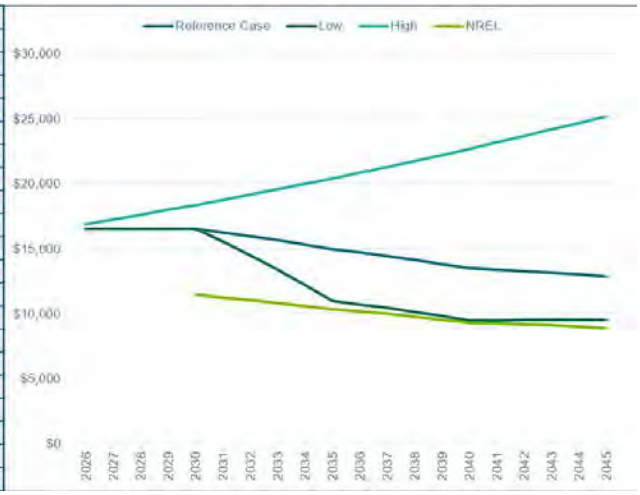
Year	Reference Case	Low	High	NREL
2026	$1,206	$1,206	$1,215	$1,425
2027	$1,223	$1,223	$1,241	$1,444
2028	$1,239	$1,239	$1,268	$1,464
2029	$1,256	$1,256	$1,295	$1,484
2030	$1,273	$1,273	$1,322	$1,504
2031	$1,290	$1,290	$1,350	$1,524
2032	$1,307	$1,307	$1,379	$1,544
2033	$1,325	$1,325	$1,408	$1,565
2034	$1,342	$1,342	$1,438	$1,585
2035	$1,360	$1,360	$1,469	$1,606
2036	$1,378	$1,378	$1,500	$1,627
2037	$1,396	$1,396	$1,532	$1,649
2038	$1,414	$1,414	$1,565	$1,670
2039	$1,432	$1,432	$1,598	$1,692
2040	$1,451	$1,451	$1,632	$1,713
2041	$1,469	$1,469	$1,667	$1,735
2042	$1,488	$1,488	$1,703	$1,757
2043	$1,506	$1,506	$1,739	$1,779
2044	$1,525	$1,525	$1,776	$1,802
2045	$1,544	$1,544	$1,814	$1,824



[42] For combustion turbines, the NREL base, low, and high curves are all identical. As such, the low and Reference Case curves are identical for this analysis. The high curve, as stated previously, is based on inflation and therefore remains unique.

Figure 8-43 – Advanced Nuclear (SMR) Capital Costs Alternate Scenarios (300 MW) ($/kW)

Year	Reference Case	Low	High	NREL
2026	$16,528	$16,528	$16,880	
2027	$16,528	$16,528	$17,239	
2028	$16,528	$16,528	$17,606	
2029	$16,528	$16,528	$17,981	
2030	$16,528	$16,528	$18,364	$11,422
2031	$16,255	$15,523	$18,755	$11,233
2032	$15,962	$14,469	$19,154	$11,031
2033	$15,650	$13,362	$19,562	$10,815
2034	$15,317	$12,201	$19,979	$10,585
2035	$14,963	$10,986	$20,404	$10,340
2036	$14,703	$10,717	$20,839	$10,161
2037	$14,425	$10,432	$21,282	$9,968
2038	$14,128	$10,130	$21,735	$9,763
2039	$13,812	$9,811	$22,198	$9,545
2040	$13,477	$9,473	$22,671	$9,313
2041	$13,378	$9,489	$23,153	$9,245
2042	$13,269	$9,501	$23,646	$9,169
2043	$13,149	$9,509	$24,150	$9,086
2044	$13,017	$9,513	$24,664	$8,996
2045	$12,875	$9,514	$25,189	$8,897



8.4.1.7. Market Sales Limits

In order to ensure the economic viability of portfolios independent of market sales, 1898 & Co. imposed a limit on energy market sales within the stochastic portfolios. This limit follows a discrete distribution with one third of draws randomly assigned 660 MW, one third assigned 330 MW, and one third assigned a 165 MW limit. 660 MW was chosen as the highest sales limit because that is approximately the capability of the physical transmission system today and thus a reasonable boundary for the IRP modeling. The lower limits, scaled to 50% and 25% of the maximum, account for the risk of lower market sales than projected under current model assumptions.

8.4.2. Rate Metric Ranking

Figure 8-44 provides the cost of each portfolio on a per kWh basis.

Figure 8-44 – Portfolio Cost Rate (¢/kWh)

Portfolio Number	Portfolio Description	(¢/kWh)
2	FBC3 NG 2035	6.50¢
1	Reference Case	6.52¢
8	Low Reg	6.58¢
12	Delayed Reference	6.71¢
11	FBC3 Co-Fire	6.74¢
3	FBC3 on Coal	7.05¢
10	Alt High Reg	7.37¢
9	High Reg	7.52¢
5	FBC3 to SCGT	7.53¢
6	Renewable Heavy	7.54¢
7	FBC3 NG with Renewables	7.65¢
4	FBC3 to SMR	7.79¢

8.5. Transmission Appendix

8.5.1. MISO Regional Transmission Planning

MISO performs the NERC functional role of Planning Coordinator on behalf of CEI South. In its NERC functional role of Transmission Planner, CEI South supports MISO's regional transmission planning processes.

MISO develops regional transmission models that are used for a variety of near-term and long-term planning studies. On an annual basis, MISO builds models to represent a 10-year planning horizon. The modeling process begins in September and concludes the following August. CEI South is responsible for submitting the required modeling data to MISO pursuant to NERC MOD-032.

CEI South participates in MISO coordinated Seasonal Transmission Assessments ("CSA") for spring, summer, fall and winter peak loads as applicable. MISO's Seasonal Assessments review projected demand and resources for the MISO footprint and assess adequacies and risks for upcoming seasons. The CSAs consider planned and unplanned generation and transmission outages. CEI South also participates in MISO Generator

Interconnection (“DPP”) and Transmission Service Requests (“TSR”) planning processes as required.

CEI South participates in MISO’s regional Transmission Expansion Plan (“MTEP”). The system expansion plans produced through the MTEP process ensure the reliable operation of the transmission system, support achievement of state and federal energy policy requirements and enable a competitive electricity market to benefit all customers. The planning process, in conjunction with an inclusive, transparent stakeholder process, identifies and supports the development of transmission infrastructure that is sufficiently robust to meet local and regional reliability standards, enables competition among wholesale capacity and energy suppliers in the MISO markets and allows for competition among transmission developers in the assignment of transmission projects.

MISO approved the LRTP Tranche 2.1 portfolio during the MTEP 2024 planning cycle. 24 transmission projects (MISO LRTP ID #19-42) were approved across the MISO Midwest, including ID #35 which includes major transmission investments in the SIGE region. The project has a targeted completion date of 2032 per MISO. The various upgrades included in LRTP project #35 consist of a new 345/138kV, 400MVA transformer at A.B. Brown substation, a new 345kV line from Duff substation to the new 765/345kV Pike County substation (AEP/DEI), a new 345kV line from Duff substation to the F.B. Culley area, and a new 345kV line from the Culley area to the Ohio River Crossing. From the river crossing, the 345kV line will continue to BREC Reid substation. Pursuant to FERC Order 1000, MISO solicited competitive bids to construct the 345kV line from the Ohio River crossing to BREC Reid substation. This project in Kentucky was awarded to Republic Transmission, LLC. CEI South, as the incumbent transmission owner, is responsible for all other modifications required for the project, apart from the terminal at BREC Reid substation. The overall project cost will be shared according to MISO’s Tariff. The Tranche 2.1 projects will provide regional economic benefits and enhanced grid reliability for the CEI South region looking into the future as generation and load profiles change across the Midwest.

8.5.2. Annual Transmission Assessment

CEI South’s most recent transmission assessment was completed in 2025. The study used MISO MTEP24 models for the year 2029 representing transmission system conditions in the winter season, summer season, and off-peak, light load conditions. The study used CEIS transmission system performance criteria as documented in VEC-008 Electric Transmission Planning Criteria as a measure to determine the strength of the SIGE transmission system. Siemens PTI PSS/E (version 35.6) software was used to conduct the assessment. The study also uses SIGE transmission ratings methodology as

documented in VEC-014 which was applied to all existing and proposed facilities. All simulations were performed using Steady State Power Flow models using AC analysis. Models were solved using the Fixed Slope Decoupled Newton-Raphson (“FDNS”) solution method with stepping transformer tap adjustments, switched shunts enabled, area interchange control enabled for tie lines and loads, DC taps disabled, and VAR limits applied automatically. Dynamic simulations were not completed in 2025, as previous dynamic studies were still deemed valid. Dynamic simulations were completed with the MTEP24 annual assessment with MISO.

The scope of this 2025 study involved several key assessments as shown below.

- Overall Reliability Assessment using NERC TPL-001 “Transmission System Planning Performance Requirements” criteria
- Reactive Power Deficiency Assessment
- Assessment of MISO Tranche 2.1 approved projects
- SIGE Import and Export Capability Assessment
- Review of the 2025 Long-Range Distribution Plan

Overall, the CEI South Bulk Electrical System (100kV and above) is expected to be stable and perform well through 2034. Normal system conditions do not result in any voltage problems or thermally overloaded facilities. Some facility outage contingencies create thermal overloads and voltage violations. When these violations cannot be effectively mitigated by operational guides, CEI South plans projects to mitigate the violations.

8.5.3. DSM Impacts on Transmission and Distribution Systems

Potential future DSM interconnection requests are currently being studied, per the planning criteria outlined in VEC-008 Electric Transmission Planning Criteria (*Technical Appendix Attachment* 3.9). If VEC-008 does not address applicable planning criteria, CEI South defaults to MISO’s criteria.

At this time, no controllable loads or demand side management resources exist on CEI South’s transmission system.

8.6. Public Advisory Process Appendix

As defined by 170 IAC, the public advisory process refers to a set of procedures that provide customers and interested parties with the opportunity to receive information from the utilities, provide input for the utility to consider in the development of the IRP, and comment on a utility's IRP.

Highlights:

- CEI South views the public as an essential partner in developing our integrated resource plan and therefore strives to conduct an inclusive stakeholder process that encourages feedback.

- CEI executive leadership and subject matter experts attended public meetings to hear feedback and respond to questions.

- CEI South held four public (in person and virtual) meetings. An average of 70 individuals, representing local residents and over 30 organizations, registered for the public meetings.

- Three virtual technical meetings were held with interested stakeholders who signed an NDA. Leadership and subject matter experts attended the technical meetings to hear feedback and respond to questions.

- Stakeholder feedback made an impact on various aspects of the IRP, including assumptions, scenarios, sensitivities, and scorecard metrics.

8.6.1. Foundational Elements

Framework

Ensuring meaningful and sustained stakeholder engagement is crucial to the public advisory process. CEI South's Stakeholder Engagement Framework serves as a guide for fostering substantive and impactful discourse. The Framework is built on four objectives: Inform, Consult, Involve, and Collaborate. Figure 8-45 highlights the alignment among a sample of CEI's engagement activities and the Framework objectives.

Figure 8-45 - Stakeholder Engagement Framework



Stakeholders

CEI South's IRP development is a robust process involving input from many stakeholders, including, but are not limited to, CEI South residential, commercial and industrial customers, regulators, customer advocacy groups, environmental advocacy groups, fuel suppliers and advocacy groups, shareholders, economic development groups, generation developers, and elected officials.

8.6.2. Engagement Resources and Strategies

Given the significant impact IRP decisions can have, conducting the IRP with transparency and full participation from interested stakeholders is essential. CEI South implemented engagement resources and strategies to encourage wide participation.

Engagement Resources

Website

Throughout the 2025 IRP process, CEI South's IRP website[43] served as an information hub for stakeholders. Meeting materials (presentations and post-meeting summaries) as well as the registration links for public meetings were published on the site. Prior IRP materials are also available on the website.

Meeting Notifications

CEI South maintains a confidential IRP stakeholder contact list. With over 300 individual contacts, the list includes CEI South customers, advocates, technical/industry experts, regulators, elected officials, etc. The list is updated throughout the IRP process to ensure new registrants or interested individuals are added. Those on the list received several meeting-related notifications: 1) invitations and reminders to register for meetings via the posted registration link, 2) meeting reminders for registrants, 3) posting of meeting presentation prior to the meeting, and 4) posting of meeting summary after the meeting.

Email Communications

CEI South continued to use a dedicated IRP email address for IRP-related communications. The simple and singular email address provided an easy method for stakeholders to stay involved and engaged outside the public meetings. Stakeholders' written requests for information and CEI South's subsequent responses were also administered through irp@centerpointenergy.com.

File Share

Technical stakeholders, with signed NDAs, were provided access to a secure file share site. The site served as a repository for modeling files and other detailed data and inputs used in the development of the 2025 IRP. The data release schedule and data type were included in the public and Tech-to-Tech meeting presentations.

Engagement Strategies

Stakeholder Meetings

CEI South again engaged 1898 & Co., a third-party consultant and facilitator, to assist in facilitation and support CEI SOUTH's focus on conducting the IRP with full participation from stakeholders. In collaboration with 1898, CEI South hosted four public stakeholder meetings and three technical meetings during the 2025 IRP process. Highlighting the

[43] CEI South, Integrated Resource Plan website available at https://www.centerpointenergy.com/irp

importance of the meetings, CEI South executive leadership actively participated as presenters and subject matter experts.

Presentations and discussions covered various issues regarding inputs, assumptions, risks, modeling methodology, planned sensitivities and analytical results. To ensure ample opportunity for participants to ask questions, provide feedback, and share information, designated Q&A and feedback periods were included in the agendas. If feedback was received following the meetings, questions were answered via e-mail (irp@centerpointenergy.com) and/or during subsequent public or tech-to-tech meetings, as appropriate.

Public Meetings
In a continued effort to remove barriers to participation, CEI South provided both in-person and virtual attendance options. The CenterPoint Plaza in Evansville, Indiana served as the meeting location for the in-person option. Meeting presentations and meeting summaries, in question-and-answer format, were posted to CEI South's IRP website seven calendar days prior to the meeting and 15 calendar days following the meeting, respectively.

Figure 8-46 is a summary of the stakeholder meetings, see *Technical Appendix Attachment 4.2 Stakeholder Materials* for a comprehensive account of stakeholder meetings, presentations, and meeting summaries.

Figure 8-46 - 2025 Stakeholder Meeting Schedule



Meeting one laid the foundation of CEI South's IRP by providing an overview of the IRP process, metrics, inputs, and assumptions. In the spirit of continuous improvement, past stakeholder feedback and 2025 IRP enhancements were also covered.

2025 IRP Enhancements

1. *5 pillar-focused score card*
2. *Refreshed IRP layout*
3. *Expanded sensitivity analysis*
4. *Collaboration with Transmission & Distribution*
5. *Additional analysis of underserved energy*
6. *Data release schedule*

Meeting two, as with meetings three and four, opened with a review of stakeholder feedback and requests. Presenters also provided updates for ongoing work and furthered the discussion of inputs, modeling assumptions, portfolio methodology. A preview of the draft Reference Case modeling was also provided.

Meeting three began with an update on CEI South's generation transition timeline, followed by a review of stakeholder feedback and requests. Topics included the DSM Market Potential Study results, updates on scenario revisions and probabilistic modeling, as well as initial scenario optimization and deterministic portfolio results.

Meeting four also started with stakeholder feedback and requests. The last of the stakeholder meetings, meeting four covered the Preferred Portfolio, Alternative Preferred Portfolio and near-term action plan, as well as examined each portfolio's capacity, energy mix, and associated benefits and challenges. Presenters also shared the detailed risk metrics via a scorecard, reviewed an alternate reference case and optimization outcomes, presented sensitivity analyses, and concluded with a summary of key takeaways.

Tech-to-Tech

Tech-to-Tech meetings were held virtually and facilitated by 1898 & Co. While the meeting dates were made public, attendance was limited to self-identified technical stakeholders with executed NDAs. NDAs were provided to technical stakeholders upon request. Members of Indiana Office of Utility Consumer Counselor, Citizens Action Coalition, Reliable Energy, Sierra Club, State Utility Forecasting Group, and Indiana Utility Regulatory Commission staff were invited to attend these meetings.

The meetings allowed CEI South to share and consult with technical stakeholders on detailed, and often confidential, modeling assumptions and inputs. They also had the added benefit of increasing transparency in the planning process. Tech-to-Tech meeting dates and agendas are listed below (Figure 8-47):

Figure 8-47 - 2025 Tech-to-Tech Meetings



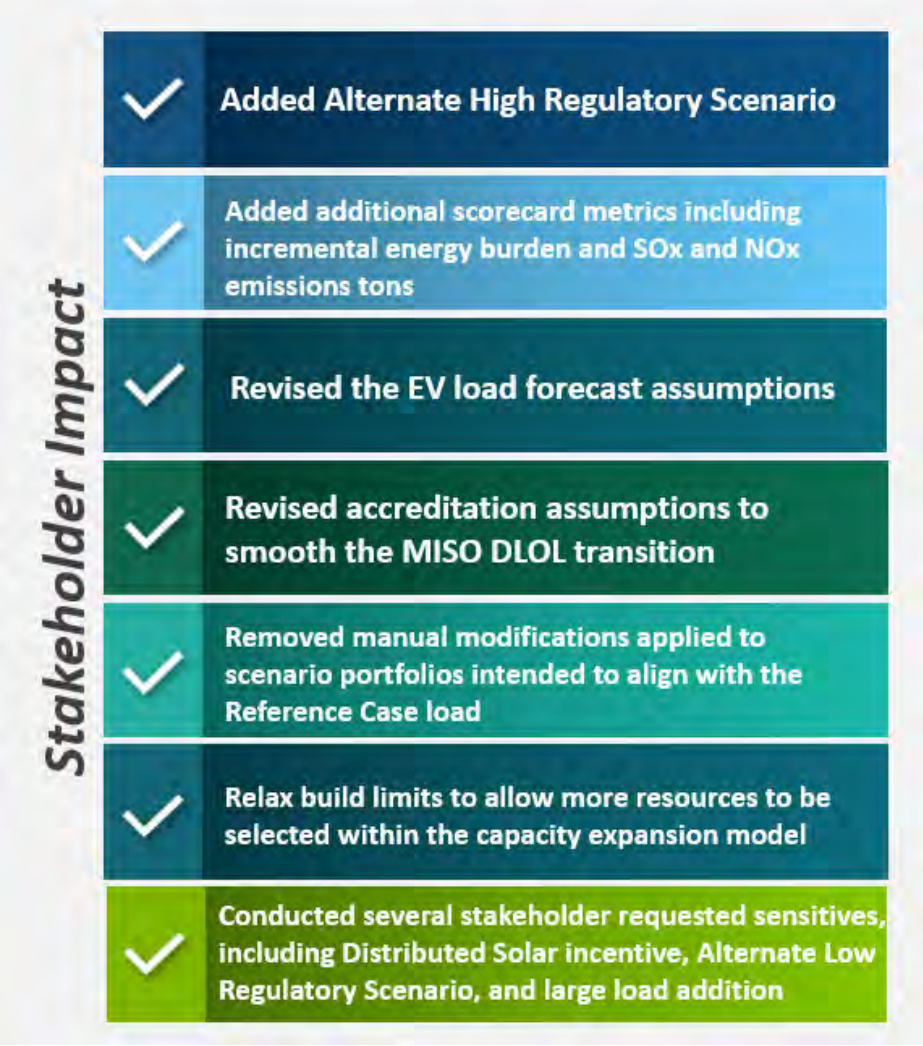
In addition to Tech-to-Tech meetings and public stakeholder meetings, CEI South met with individual stakeholders on various topics. For example, CEI South met several times with the CAC on Energy Efficiency modeling inputs.

8.6.3. Stakeholder Input

As discussed in Section 8.6.2, CEI South provided multiple avenues for engagement throughout the 2025 IRP process – dedicated Q&A and feedback time during public meetings; use of the IRP email address for written feedback/requests; Tech-to-Tech meetings between public meetings; and individual meetings upon request.
Critical to the IRP, feedback was reviewed, responded to, and incorporated as applicable.

In recognition of the importance of the received feedback, Figure 8-48 is a summary of key feedback that was ultimately included in the 2025 IRP analysis. For a full list, including suggestions not taken, see the *Technical Appendix Attachment 4.2 Stakeholder Materials*.

Figure 8-48 - Summary of Key Stakeholder Input



8.6.4. Data Requests Summary

During the public stakeholder process CEI South received seven data requests from the Citizens Action Coalition, Clean Grid Alliance, Reliable Energy, Sierra Club, Solar United, and State Utility Forecasting Group. These data requests and CEI South's response can be found in the *Technical Appendix Attachment 4.2 Stakeholder Materials*.

8.7.5 DSM OSB Presentations and Data Requests

CEI South collaborates with the CenterPoint Energy Oversight Board (which consists of CEI South, the OUCC, and CAC) on a monthly basis to discuss energy efficiency programs, results, and solicits feedback on program design and funding. This same collaborative group was utilized to discuss DSM in the 2025 Market Potential Study and

the development of energy efficiency and demand response inputs into the IRP. CEI South held seven meetings with the kickoff meeting occurring in-person at our Indianapolis office. The meeting dates and topics are listed in Figure 8-49 below, OSB stakeholder presentations can be found in *Technical Appendix Attachment 8.1 2025 MPS Slide Decks for Stakeholders*. This process allowed for robust discussion on topics to drive consensus, where possible, with several data requests and responses which can be found in *Technical Appendix Attachment 8.2 2025 DSM Data Requests and Responses*.

Figure 8-49 - DSM Oversight Board Meetings

Date	Discussion Topic
December 11, 2024	Integrated Gas & Electric Market Potential Study Kickoff
February 5, 2025	Data Request Response Updates/Observations; Measure Lists
March 6, 2025	Initial Demand Response Program Assumptions and Historical Performance Benchmarking
March 13, 2025	Additional Interruptible & Aggregation Discussion
April 17, 2025	Draft Demand Response Potential and EE Measure Assumptions
May 22, 2025	Draft EE Potential Results and Refined Demand Response Potential Results
June 30, 2025	Final EE Results and Initial IRP Inputs



Technical Appendix Attachments

Chapter 9

Attachment 1.1 Non-Technical Summary

Attachment 2.1 2024 All-Source Request for Proposal & Report

Attachment 2.2 2025 Technology Assessment Summary (Confidential)

Attachment 2.3 Transmission Study (Confidential)

Attachment 3.1 2025 CEIS Long-Term Electric Energy & Demand Forecast Report

Attachment 3.2 Energy and Demand Forecast Model Inputs-Outputs (Confidential)

Attachment 3.3 CEIS 2024 System Hourly Load

Attachment 3.4 CEIS Electric 2025-2027 DSM Plan

Attachment 3.5 Gas Pipeline Cost Estimates (Confidential)

Attachment 3.6 2025 DSM Market Potential Study

Attachment 3.7 CEIS 2025 Residential Energy Efficiency Baseline Survey

Attachment 3.8 CEIS Distribution System Long Range Planning Report

Attachment 3.9 VEC-008 Electric Transmission Planning Criteria

Attachment 4.1 CEIS 2025 IRP Model with Scenarios & Stochastics Model (Confidential)

Attachment 4.2 Stakeholder Materials

Attachment 6.1 CEIS 2025 IRP Alternate Reference Stochastics Model (Confidential)

Attachment 6.2 Large Load Study Results (Confidential)

Attachment 8.1 2025 MPS Slide Decks for Stakeholders

Attachment 8.2 2025 DSM Data Requests and Responses



IRP Rule Requirements Cross Reference Table

Chapter 10

IRP Rule Requirements Cross Reference Table

Rule	Section(s)
170 IAC 4-7-2 Integrated Resource Plan Submission Section 2	
(c) On or before the applicable date, a utility subject to subsection (a) or (b) must submit electronically to the director or through an electronic filing system if requested by the director, the following documents:	
(1) The IRP.	2025 IRP submitted on December 5, 2025
(2) A technical appendix containing supporting documentation sufficient to allow an interested party to evaluate the data and assumptions in the IRP. The technical appendix shall include at least the following: (A) The utility's energy and demand forecasts and input data used to develop the forecasts. (B) The characteristics and costs per unit of resources examined in the IRP; (C) Input and output files from capacity planning models, in electronic format. (D) For each portfolio, the electronic files for the calculation of the revenue requirement if not provided as an output file. If a utility does not provide the above information, it shall include a statement in the technical appendix specifying the nature of the information it is omitting and the reason necessitating its omission. The utility may request confidential treatment of the technical appendix under section 2.1 of this rule.	8 Technical Appendix; 9 Technical Appendix Attachments
(3) An IRP summary that communicates core IRP concepts and results to nontechnical audiences in a simplified format using visual elements where appropriate. The IRP summary shall include, but is not limited to, the following: (A) A brief description of the utility's: (i) existing resources; (ii) preferred resource portfolio; (iii) key factors influencing the preferred resource portfolio; (iv) short term action plan; (v) public advisory process; and (vi) additional details requested by the director. (B) A simplified discussion of the utility's resource types and load characteristics.	Executive Summary (Non-Technical Summary Document)
The utility shall make the IRP summary readily accessible on its website.	www.centerpointenergy.com/irp

Rule	Section(s)
170 IAC 4-7-2.6 Public advisory process Sec. 2.6	
(b) The utility shall provide information requested by an interested party relating to the development of the utility's IRP within 15 business days of a written request or as otherwise agreed to by the utility and the interested party. If a utility is unable to provide the requested information within 15 business days or the agreed timeframe, it shall provide a statement to the director and the requestor as to the reason it is unable to provide the requested information.	2.4 Stakeholder Engagement; 8.6 Public Advisory Process Appendix; 9 Technical Appendix Attachment 4.2 Stakeholder Materials
(c) The utility shall solicit, consider and timely respond to relevant input relating to the development of the utility's IRP provided by: (1) interested parties; (2) the OUCC; and (3) commission staff.	2.4 Stakeholder Engagement; 8.6 Public Advisory Process Appendix; 9 Technical Appendix Attachment 4.2 Stakeholder Materials
(d) The utility retains full responsibility for the content of its IRP.	n/a
(e) The utility shall conduct a public advisory process as follows: (1) Prior to submitting its IRP to the commission, the utility shall hold at least three (3) meetings, a majority of which shall be held in the utility's service territory. The topics discussed in the meetings shall include, but not be limited to, the following:	2.4 Stakeholder Engagement; 8.6 Public Advisory Process Appendix; 9 Technical Appendix Attachment 4.2 Stakeholder Materials
(A) An introduction to the IRP and public advisory process. (B) The utility's load forecast. (C) Evaluation of existing resources. (D) Evaluation of supply-side and demand-side resource alternatives, including: (i) associated costs; (ii) quantifiable benefits; and (iii) performance attributes. (E) Modeling methods. (F) Modeling inputs. (G) Treatment of risk and uncertainty. (H) Discussion seeking input on its candidate resource portfolios. (I) The utility's scenarios and sensitivities. (J) Discussion of the utility's preferred resource portfolio and the utility's rationale for its selection.	2.4 Stakeholder Engagement; 8.6 Public Advisory Process Appendix; 9 Technical Appendix Attachment 4.2 Stakeholder Materials
(2) The utility may hold additional meetings.	2.4 Stakeholder Engagement; 8.6 Public Advisory Process Appendix; 9 Technical Appendix Attachment 4.2 Stakeholder Materials
(3) The schedule for meetings shall:	2.4 Stakeholder Engagement;

Rule	Section(s)
(A) be determined by the utility; (B) be consistent with its internal IRP development schedule; and (C) provide an opportunity for public participation in a timely manner so that it may affect the outcome of the IRP.	8.6 Public Advisory Process Appendix; 9 Technical Appendix Attachment 4.2 Stakeholder Materials
170 IAC 4-7-4 Integrated resource plan contents Sec. 4	
An IRP must include the following: (1) At least a twenty (20) year future period for predicted or forecasted analyses.	3.1.4 Reference Case
(2) An analysis of historical and forecasted levels of peak demand and energy usage in compliance with section 5(a) of this rule.	8.1.2 Overview of Past Forecasts
(3) At least three (3) alternative forecasts of peak demand and energy usage in compliance with section 5(b) of this rule.	3.1.5 Alternative Scenarios
(4) A description of the utility's existing resources in compliance with section 6(a) of this rule.	3.7.1 Current Resource Mix
(5) A description of the utility's process for selecting possible alternative future resources for meeting future demand for electric service, including a cost-benefit analysis, if performed.	3.7 Resource Options; 4 Portfolio Development and Evaluation
(6) A description of the possible alternative future resources for meeting future demand for electric service in compliance with section 6(b) of this rule.	3.7 Resource Options
(7) The resource screening analysis and resource summary table required by section 7 of this rule.	3.7 Resource Options; Figure 3-40; Figure 3-41
(8) A description of the candidate resource portfolios and the process for developing candidate resource portfolios in compliance with section 8(a) and 8(b) of this rule.	4 Portfolio Development and Evaluation
(9) A description of the utility's preferred resource portfolio and the information required by section 8(c) of this rule.	4 Portfolio Development and Evaluation; 5 The Preferred Portfolio; 6 The Alternate Preferred Portfolio
(10) A short term action plan for the next three (3) year period to implement the utility's preferred resource portfolio and its workable strategy, pursuant to section 9 of this rule.	7 Short Term Action Plan
(11) A discussion of the: (A) inputs; (B) methods; and (C) definitions; used by the utility in the IRP.	11 List of Acronyms/Abbreviations with Definitions; 2 Resource Planning Process; 4 Portfolio Development and Evaluation
(12) Appendices of the data sets and data sources used to establish alternative forecasts in section 5(b) of this rule. If	9 Technical Appendix Attachments

Rule	Section(s)
the IRP references a third-party data source, the IRP must include for the relevant data: (A) source title; (B) author; (C) publishing address; (D) date; (E) page number; and (F) an explanation of adjustments made to the data. The data must be submitted within two (2) weeks of submitting the IRP in an editable format, such as a comma separated value or excel spreadsheet file.	
(13) A description of the utility's effort to develop and maintain a database of electricity consumption patterns, disaggregated by: (A) customer class; (B) rate class; (C) NAICS code; (D) DSM program; and (E) end-use. 14) The database in subdivision (13) may be developed using, but not limited to, the following methods: (A) Load research developed by the individual utility. (B) Load research developed in conjunction with another utility. (C) Load research developed by another utility and modified to meet the characteristics of that utility. (D) Engineering estimates. (E) Load data developed by a non-utility source.	3.7 Resource Options; 9 Technical Appendix Attachment 3.1 2025 CEIS Long-Term Electric Energy & Demand Forecast Report; 8.1.1.1 Energy Data; 8.1.1.4 Equipment Efficiencies and Market Share Data
(15) A proposed schedule for industrial, commercial and residential customer surveys to obtain data on: (A) end-use penetration; (B) end-use saturation rates; and (C) end-use electricity consumption patterns.	8.1.1.4 Equipment Efficiencies and Market Share Data
(16) A discussion detailing how information from advanced metering infrastructure and smart grid, where available, will be used to enhance usage data and improve load forecasts, DSM programs and other aspects of planning.	8.1.5 Advanced Metering Infrastructure and Continuous Improvement
(17) A discussion of the designated contemporary issues designated, if required by section 2.7(e).	Executive Summary Section V. Stakeholder Process
(18) A discussion of distributed generation within the service territory and its potential effects on: (A) generation planning; (B) transmission planning; (C) distribution planning; and	3.8 Transmission Planning and Distribution Planning; 4.1.1.1.3 Distributed Generation Resource Portfolios;

Rule	Section(s)
(D) load forecasting.	9 Technical Appendix Attachment 3.1 2025 CEIS Long-Term Electric Energy & Demand Forecast Report
(19) For models used in the IRP, including optimization and dispatch models, a description of the model's structure and applicability.	2.11.2 Modeling Tools
(20) A discussion of how the utility's fuel inventory and procurement planning practices have been taken into account and influenced the IRP development.	5.1.8 Fuel Inventory and Procurement Planning
(21) A discussion of how the utility's emission allowance inventory and procurement practices for an air emission have been considered and influenced the IRP development.	8.2.1 Air Emissions
(22) A description of the generation expansion planning criteria. The description must fully explain the basis for the criteria selected.	3 Forecasts and Key Modeling Assumptions; 4 Portfolio Development and Evaluation
(23) A discussion of how compliance costs for existing or reasonably anticipated air, land, or water environmental regulations impacting generation assets have been taken into account and influenced the IRP development.	2.1 Planning Scenarios; 2.6 Reference Case; 2.7 Alternative Scenarios; 3.5 Environmental Regulations
(24) A discussion of how the utilities' resource planning objectives, such as: (A) cost effectiveness; (B) rate impacts; (C) risks; and (D) uncertainty; were balanced in selecting its preferred resource portfolio.	4 Portfolio Development and Evaluation; 5 The Preferred Portfolio; 6 The Alternate Preferred Portfolio
(25) A description and analysis of the utility's Reference Case scenario, sometimes referred to a business as usual case or reference case. The Reference Case scenario is the most likely future scenario and must meet the following criteria: (A) Be an extension of the status quo, using the best estimate of forecasted electrical requirements, fuel price projections and an objective analysis of the resources required over the planning horizon to reliably and economically satisfy electrical needs. (B) Include: (i) existing federal environmental laws; (ii) existing state laws, such as renewable energy requirements and energy efficiency laws; and (iii) existing policies, such as tax incentives for renewable resources.	2.6 Reference Case

Rule	Section(s)
(C) Existing laws or policies continuing throughout at least some portion of the planning horizon with a high probability of expiration or repeal must be eliminated or altered when applicable. (D) Not include future resources, laws, or policies unless: (i) a utility subject to section 2.6 of this rule solicits stakeholder input regarding the inclusion and describes the input received; (ii) future resources have obtained the necessary regulatory approvals; and (iii) future laws and policies have a high probability of being enacted. A Reference Case scenario need not align with the utility's preferred resource portfolio.	
(26) A description and analysis of alternative scenarios to the Reference Case scenario, including comparison of the alternative scenarios to the Reference Case scenario.	2.7 Alternative Scenarios
(27) A brief description of the models(s), focusing on the utility's Indiana jurisdictional facilities, of the following components of FERC Form 715: (A) The most current power flow data models, studies and sensitivity analysis. (B) Dynamic simulation on its transmission system, including interconnections, focused on the determination of the performance and stability of its transmission system on various fault conditions. The description must state whether the simulation meets the standards of the North American Electric Reliability Corporation (NERC). (C) Reliability criteria for transmission planning as well as the assessment practice used. This description must include the following: (i) The limits of the utility's transmission use. (ii) The utility's assessment practices developed through experience and study. (iii) Operating restrictions and limitations particular to the utility.	3.8 Transmission and Distribution Planning 8.5.1 MISO Regional Transmission Planning 9 Technical Appendix Attachment 3.9 VEC-008 Electric Transmission Planning Criteria
(28) A list and description of the methods used by the utility in developing the IRP, including the following: (A) For models used in the IRP, the model's structure and reasoning for its use. (B) The utility's effort to develop and improve the methodology and inputs, including for its: (i) load forecast;	2 Resource Planning Process; 3 Forecasts and Key Assumptions; 4 Portfolio Development and Evaluation; 8.1.1.5 Load Forecast Continuous Improvement; 8.6 Public Advisory Process Appendix;

Rule	Section(s)
(ii) forecasted impact from demand-side programs; (iii) cost estimates; and (iv) analysis of risk and uncertainty.	9 Technical Appendix Attachment 3.1 2025 CEIS Long-Term Electric Energy & Demand Forecast Report; 9 Technical Appendix Attachment 3.2 Energy and Demand Forecast Model Inputs-Outputs (Confidential); 9 Technical Appendix Attachment 3.6 2025 DSM Market Potential Study
(29) An explanation, with supporting documentation, of the avoided cost calculation for each year in the forecast period, if the avoided cost calculation is used to screen demand-side resources. The avoided cost calculation must reflect timing factors specific to the resource under consideration such as project life and seasonal operation. The avoided cost calculation must include the following: (A) The avoided generating capacity cost adjusted for transmission and distribution losses and the reserve margin requirement. (B) The avoided transmission capacity cost. (C) The avoided distribution capacity cost. (D) The avoided operating cost, including: (i) fuel cost; (ii) plant operation and maintenance costs; (iii) spinning reserve; (iv) emission allowances; (v) environmental compliance costs; and (vi) transmission and distribution operation and maintenance costs.	8.3.5 Avoided Costs
(30) A summary of the utility's most recent public advisory process, including the following: (A) Key issues discussed. (B) How the utility responded to the issues. (C) A description of how stakeholder input was used in developing the IRP.	Executive Summary; 2.4 Stakeholder Engagement; 8.6 Public Advisory Process Appendix; 9 Technical Appendix Attachment 4.2 Stakeholder Materials
(31) A detailed explanation of the assessment of demand-side and supply-side resources considered to meet future customer electricity service needs.	3.7 Resource Options; 3.9.1 Resource Availability 3.8.4 Transmission Facilities as a Resource;
170 IAC 4-7-5 Energy and demand forecasts Sec. 5.	
(a) The analysis of historical and forecasted levels of peak demand and energy usage must include the following: (1) Historical load shapes, including the following:	8.1.4 Load Shapes; 9 Technical Appendix Attachment 3.1 2025 CEIS Long-

Rule	Section(s)
(A) Annual load shapes. (B) Seasonal load shapes. (C) Monthly load shapes. (D) Selected weekly load shapes. (E) Selected daily load shapes, which shall include summer and winter peak days and a typical weekday and weekend day.	Term Electric Energy & Demand Forecast Report; 9 Technical Appendix Attachment 3.3 CEIS 2024 System Hourly Load
(2) Disaggregation of historical data and forecasts by: (A) customer class; (B) interruptible load; and (C) end-use; where information permits.	8.1.2 Overview of Past Forecasts; 9 Technical Appendix Attachments Attachment 3.1 2025 CEIS Long-Term Electric Energy & Demand Forecast Report
(3) Actual and weather normalized energy and demand levels.	8.1.2 Overview of Past Forecasts
(4) A discussion of methods and processes used to weather normalize.	8.1.2 Overview of Past Forecasts
(5) A minimum twenty (20) year period for peak demand and energy usage forecasts.	3.1.4 Reference Case
(6) An evaluation of the performance of peak demand and energy usage for the previous ten (10) years, including the following: (A) Total system. (B) Customer classes or, rate classes, or both. (C) Firm wholesale power sales.	8.1.2 Overview of Past Forecasts
(7) A discussion of how the impact of historical DSM programs is reflected in or otherwise treated in the load forecast.	9 Technical Appendix Attachments 3.1 2025 CEIS Long-Term Electric Energy & Demand Forecast Report
(8) Justification for the selected forecasting methodology.	9 Technical Appendix Attachments 3.1 2025 CEIS Long-Term Electric Energy & Demand Forecast Report
(9) A discussion of the potential changes under consideration to improve the credibility of the forecasted demand by improving the data quality, tools and analysis.	8.1.1.5 Load Forecast Continuous Improvement
(10) For purposes of subdivisions (1) and (2), a utility may use utility specific data or data such as described in section 4(14) of this rule.	n/a
(b) To establish plausible risk boundaries, the utility shall provide at least three (3) alternative forecasts of peak demand and energy usage including: (1) high; (2) low; and (3) most probable; peak demand and energy use forecasts.	3.1.5 Alternate Scenarios

Rule	Section(s)
(c) In determining the peak demand and energy usage forecast that is deemed by the utility, with stakeholder input, to be most probable, the utility shall consider alternative assumptions such as: (1) Rate of change in population. (2) Economic activity. (3) Fuel prices. (4) Price elasticity. (5) Penetration of new technology. (6) Demographic changes in population. (7) Customer usage. (8) Changes in technology. (9) Behavioral factors affecting customer consumption. (10) State and federal energy policies. (11) State and federal environmental policies.	3.1 Load Forecast; 9 Technical Appendix Attachment 3.1 2025 CEIS Long-Term Electric Energy & Demand Forecast Report
170 IAC 4-7-6 Description of available resources	
Sec. 6. (a) In describing its existing electric power resources, the utility must include in its IRP the following information relevant to the twenty (20) year planning period being evaluated: The net and gross dependable generating capacity of the system and each generating unit. The information listed in subdivision (a)(1) through (a)(4) shall be provided for each year of the future planning period.	3.7.1 Current Resource Mix
(2) The expected changes to existing generating capacity, including the following: (A) Retirements. (B) Deratings. (C) Plant life extensions. (D) Repowering. (E) Refurbishment. The information listed in subdivision (a)(1) through (a)(4) shall be provided for each year of the future planning period.	3.7.1 Current Resource Mix; 9 Technical Appendix Attachment 4.1 CEIS 2025 IRP Model with Scenarios & Stochastics Model (Confidential); 9 Technical Appendix Attachment 6.1 CEIS 2025 IRP Alternate Reference Stochastics Model (Confidential)
(3) A fuel price forecast by generating unit. The information listed in subdivision (a)(1) through (a)(4) shall be provided for each year of the future planning period.	9 Technical Appendix Attachment 4.1 CEIS 2025 IRP Model with Scenarios & Stochastics Model (Confidential); 9 Technical Appendix Attachment 6.1 CEIS 2025 IRP

Rule	Section(s)
	Alternate Reference Stochastics Model (Confidential)
(4) The significant environmental effects, including: (A) air emissions; (B) solid waste disposal; (C) hazardous waste; and(D) subsequent disposal; and (E) water consumption and discharge; at existing fossil fueled generating units. The information listed in subdivision (a)(1) through (a)(4) shall be provided for each year of the future planning period.	8.2 Environmental Appendix
(5) An analysis of the existing utility transmission system that includes the following: (A) An evaluation of the adequacy to support load growth and expected power transfers. (B) An evaluation of the supply-side resource potential of actions to reduce: (i) transmission losses; (ii) congestion; and (iii) energy costs. (C) An evaluation of the potential impact of demand-side resources on the transmission network.	8.5 Transmission Appendix
(6) A discussion of demand-side resources and their estimated impact on the utility's historical and forecasted peak demand and energy. (a)(6) shall be provided for each year of the future planning period.	3.7 Resource Options; 8.3 DSM Appendix
The information listed in subdivision (a)(1) through (a)(4) and in subdivision (a)(6) shall be provided for each year of the future planning period.	Included in Sec. 6 (a)(1) through (a)(4) and in subdivision (a)(6)
(b) In describing possible alternative methods of meeting future demand for electric service, a utility must analyze the following resources as alternatives in meeting future electric service requirements: (1) Rate design as a resource in meeting future electric service requirements.	3.7.2.14 Innovative Rate Design
(2) Demand-side resources. For potential demand-side resources, the utility shall include the following: (A) A description of the potential demand-side resource, including its costs, characteristics and parameters. (B) The method by which the costs, characteristics and other parameters of the demand-side resource are determined.	3.7.2.10 Energy Efficiency; 3.7.2.10.1 DSM Market Potential Study; 3.7.2.11 Demand Response; 3.7.2.13 DSM Improvements Based on Stakeholder Feedback;

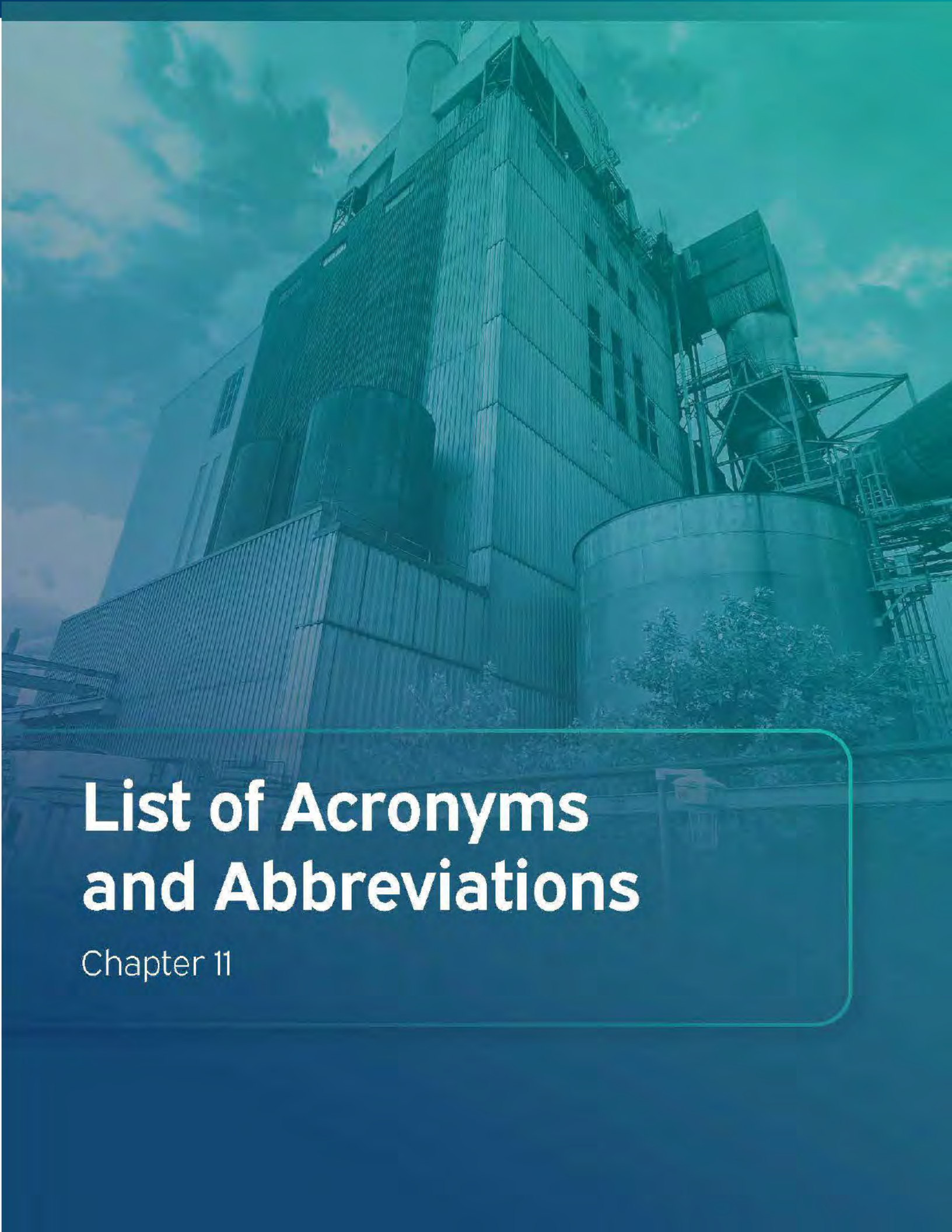
Rule	Section(s)
(C) The customer class or end-use, or both, affected by the demand-side resource. (D) Estimated annual and lifetime energy (kWh) and demand (kW) savings. (E) The estimated impact of a demand-side resource on the utility's load, generating capacity and transmission and distribution requirements. (F) Whether the program provides an opportunity for all ratepayers to participate, including low-income residential ratepayers.	9 Technical Appendix Attachment 3.6 2025 DSM Market Potential Study
(3) Supply-side resources. For potential supply-side resources, the utility shall include the following:	
(A) Identification and description of the supply-side resource considered, including the following: (i) Size in megawatts. (ii) Utilized technology and fuel type. (iii) Energy profile of non-dispatchable resources. (iv) Additional transmission facilities necessitated by the resource. (B) A discussion of the utility's effort to coordinate planning, construction and operation of the supply-side resource with other utilities to reduce cost. (C) A description of significant environmental effects, including the following: (i) Air emissions. (ii) Solid waste disposal. (iii) Hazardous waste and subsequent disposal. (iv) Water consumption and discharge.	3.7 Resource Options; 3.9.1 Resource Availability; 9 Technical Appendix Attachment 2.2 2025 Technology Assessment Summary (Confidential); 9 Technical Appendix Attachment 4.1 CEIS 2025 IRP Model with Scenarios & Stochastics Model (Confidential); 9 Technical Appendix Attachment 6.1 CEIS 2025 IRP Alternate Reference Stochastics Model (Confidential)
(4) Transmission facilities as resources. In analyzing transmission resources, the utility shall include the following:	
(A) The type of the transmission resource, including whether the resource consists of one (1) of the following: (i) New projects. (ii) Upgrades to transmission facilities. (iii) Efficiency improvements. (iv) Smart grid technology. (B) A description of the timing, types of expansion and alternative options considered. (C) The approximate cost of expected expansion and alteration of the transmission network. (D) A description of how the IRP accounts for the value of new or upgraded transmission facilities increasing power transfer capability, thereby	3.8.4 Transmission Facilities as a Resource; 8.5 Transmission Appendix

Rule	Section(s)
increasing the utilization of geographically constrained cost-effective resources. (E) A description of how: (i) IRP data and information affect the planning and implementation processes of the RTO of which the utility is a member; and (ii) RTO planning and implementation processes affect the IRP.	
170 IAC 4-7-7 Selection of resources	
Sec. 7. (a) To eliminate nonviable alternatives, a utility shall perform an initial screening of the future resource alternatives listed in section 6(b) of this rule. The utility's screening process and the decision to reject or accept a resource alternative for further analysis must be fully explained and supported in the IRP. The screening analysis must be additionally summarized in a resource summary table.	N/A
170 IAC 4-7-8 Resource portfolios Sec. 8	
(a) The utility shall develop candidate resource portfolios from existing and future resources identified in sections 6 and 7 of this rule. The utility shall provide a description of its process for developing its candidate resource portfolios, including a description of its optimization modeling, if used. In selecting the candidate resource portfolios, the utility shall at a minimum consider: (1) risk; (2) uncertainty; (3) regional resources; (4) environmental regulations; (5) projections for fuel costs; (6) load growth uncertainty; (7) economic factors; and (8) technological change.	4 Portfolio Development and Evaluation; 5 The Preferred Portfolio; 6 The Alternate Preferred Portfolio
(b) With regard to candidate resource portfolios, the IRP must include the following: (1) An analysis of how candidate resource portfolios performed across a wide range of potential future scenarios, including the alternative scenarios required under section 4(25) of this rule. (2) The results of testing and rank ordering of the candidate resource portfolios by key resource planning objectives, including cost effectiveness and risk metrics. (3) The present value of revenue requirement for each candidate resource portfolio in dollars per	4 Portfolio Development and Evaluation; 8.4.2 Rate Metric Ranking

Rule	Section(s)
kilowatt-hour delivered, with the interest rate specified.	
(c) Considering the analyses of the candidate resource portfolios, a utility shall select a preferred resource portfolio and include in the IRP the following: (1) A description of the utility's preferred resource portfolio. (2) Identification of the standards of reliability. (3) A description of the assumptions expected to have the greatest effect on the preferred resource portfolio. (4) An analysis showing that supply-side resources and demand-side resources have been evaluated on a consistent and comparable basis, including consideration of: (A) safety; (B) reliability; (C) risk and uncertainty; (D) cost effectiveness; and (E) customer rate impacts.	4 Portfolio Development and Evaluation; 5 The Preferred Portfolio; 6 The Alternate Preferred Portfolio
(5) An analysis showing the preferred resource portfolio utilizes supply-side resources and demand-side resources that safely, reliably, efficiently and cost-effectively meets the electric system demand taking cost, risk and uncertainty into consideration.	5 The Preferred Portfolio; 6 The Alternate Preferred Portfolio
(6) An evaluation of the utility's DSM programs designed to defer or eliminate investment in a transmission or distribution facility, including their impacts on the utility's transmission and distribution system.	8.5.3 DSM Impacts on Transmission and Distribution Systems
(7) A discussion of the financial impact on the utility of acquiring future resources identified in the utility's preferred resource portfolio including, where appropriate, the following: (A) Operating and capital costs of the preferred resource portfolio. (B) The average cost per kilowatt-hour of the future resources, which must be consistent with the electricity price assumption used to forecast the utility's expected load by customer class in section 5 of this rule. (C) An estimate of the utility's avoided cost for each year of the preferred resource portfolio. (D) The utility's ability to finance the preferred resource portfolio.	5 The Preferred Portfolio; 6 The Alternate Preferred Portfolio: 7.2.6 Ability to Finance the Preferred Portfolio; 8.3.5 Avoided Costs; 8.4.2 Rate Metric Ranking; 9 Technical Appendix Attachment 4.1 CEIS 2025 IRP Model with Scenarios & Stochastics Model (Confidential)
(8) A description of how the preferred resource portfolio balances cost effectiveness, reliability and portfolio risk and uncertainty, including the following:	Executive Summary; 1 Integrated Resource Planning; 2 Resource Planning Process;

Rule	Section(s)
(A) Quantification, where possible, of assumed risks and uncertainties, including, but not limited to: (i) environmental and other regulatory compliance; (ii) reasonably anticipated future regulations; (iii) public policy; (iv) fuel prices; (v) operating costs; (vi) construction costs; (vii) resource performance; (viii) load requirements; (ix) wholesale electricity and transmission prices; (x) RTO requirements; and (xi) technological progress. (B) An assessment of how robustness of risk considerations factored into the selection of the preferred resource portfolio.	4 Portfolio Development and Evaluation; 5 The Preferred Portfolio; 6 The Alternate Preferred Portfolio; 9 Technical Appendix Attachment 4.1 CEIS 2025 IRP Model with Scenarios & Stochastics Model (Confidential)
(9) Utilities shall include a discussion of potential methods under consideration to improve the data quality, tools and analysis as part of the ongoing efforts to improve the credibility and efficiencies of their resource planning process.	2.11.3 Process Enhancements; 3.7.2.13 DSM Improvements Based on Stakeholder Feedback; 3.7.2.14 Innovative Rate Design; 7.2.7 Continuous Improvement; 8.1.1.5 Load Forecast Continuous Improvement; 8.1.5 Advanced Metering Infrastructure Continuous Improvement; 8.3.7 Appliance Saturation Survey
(10) A workable strategy to quickly and appropriately adapt its preferred resource portfolio to unexpected circumstances, including changes in the following: (A) Demand for electric service. (B) Cost of new supply-side resources or demand-side resources. (C) Regulatory compliance requirements and costs. (D) Wholesale market conditions. (E) Fuel costs. (F) Environmental compliance costs. (G) Technology and associated costs and penetration. (H) Other factors which would cause the forecasted relationship between supply and demand for electric service to be in error.	4 Portfolio Development and Evaluation; 5 The Preferred Portfolio; 6 The Alternate Preferred Portfolio; 7 Short Term Action Plan

Rule	Section(s)
170 IAC 4-7-9 Short term action plan Sec. 9	
(a) A utility shall prepare a short term action plan as part of its IRP and shall cover a three (3) year period beginning with the first year of the IRP submitted pursuant to this rule.	7 Short Term Action Plan
(b) The short-term action plan shall summarize the utility's preferred resource portfolio and its workable strategy, as described in section 8(c)(9) of this rule, where the utility must act or incur expenses during the three (3) year period.	7 Short Term Action Plan
(c) The short term action plan must include, but is not limited to, the following: (1) A description of resources in the preferred resource portfolio included in the short term action plan. The description may include references to other sections of the IRP to avoid duplicate descriptions. The description must include, but is not limited to, the following: (A) The objective of the preferred resource portfolio. (B) The criteria for measuring progress toward the objective.	7 Short Term Action Plan
(2) Identification of goals for implementation of DSM programs that can be developed in accordance with IC 8-1-8.5-10, 170 IAC 4-8-1 *et seq*. and consistent with the utility's longer resource planning objectives.	3.7.2.10 Energy Efficiency; 3.7.2.10.1 DSM Market Potential Study; 7.2 Discussion Of Plans For The Next 3 Years
(3) The implementation schedule for the preferred resource portfolio.	7.3 Schedule
(4) A budget with an estimated range for the cost to be incurred for each resource or program and expected system impacts.	7 Short Term Action Plan; 9 Technical Appendix Attachment 4.1 CEIS 2025 IRP Model with Scenarios & Stochastics Model (Confidential)
(5) A description and explanation of differences between what was stated in the utility's last filed short-term action plan and what actually occurred.	7.1 Differences Between the Last Short Term Action Plan from What Transpired



List of Acronyms and Abbreviations

Chapter 11

List of Acronyms/Abbreviation

1898 & Co.	1898 & Co., a part of Burns & McDonnell
AAR	Ambient Adjusted Rating
ABB	Power Consulting Company (Hitachi Predecessor)
ABB	A.B. Brown Generating Station
ACE	Affordable Clean Energy
ADR	Aggregation Demand Response
AEO	Annual Energy Outlook
AI	Artificial Intelligence
AMI	Advanced Metering Infrastructure
ATB	Annual Technology Baseline
ATC	Around the Clock
AUPC	Average Use Per Customer
BAU	Business as Usual
BES	Bulk Electric System
BESS	Battery Energy Storage System
Btu	British Thermal Unit
BYOT	Bring Your Own Thermostat
CAA	Clean Air Act
C&I	Commercial and Industrial
CAC	Citizens Action Coalition
CAES	Compressed Air Energy Storage
CAGR	Compound Annual Growth Rate
CCGT	Combined Cycle Gas Turbine
CCR	Coal Combustion Residuals
CDD	Cooling Degree Day
CNP	CenterPoint Energy
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide equivalent
CONE	Cost of New Entry
CPCN	Certificate of Public Convenience and Necessity
CPP	Critical Peak Pricing
CRL	Combustion Residual Leachate
CSA	Coordinated Seasonal Transmission Assessment
CSAPR	Cross State Air Pollution Rule
CT	Combustion Turbine
CVR	Conservation Voltage Reduction
CWIS	Cooling Water Intake Structures
DC	Direct Current
DCP	Distributed Capacity Procurement
DG	Distributed Generation
DGS	Demand General Service
DLC	Direct Load Control

DLOL	Direct Loss of Load
DPP	Definitive Planning Phase
DR	Demand Response DSM Demand Side Management
DSMA	Demand Side Management Adjustment
eCFR	Electronic Code of Federal Regulations
EE	Energy Efficiency
EEFC	Energy Efficiency Funding Component
$EFOR_d$	Equivalent Forced Outage
EGU	Electric Generation Units
EIA	Energy Information Administration
ELCC	Effective Load Carrying Capability
ELG	Effluent Limitation Guidelines
EM&V	Evaluation, Measurement and Verification
EPA	U.S. Environmental Protection Agency
ERAS	Expedited Resource Addition Study
EV	Electric Vehicle
EVA	Energy Ventures Analysis, Inc.
FBC	F.B. Culley Generating Station
FBC3	F.B. Culley Unit 3
FDNS	Fixed Slope Decoupled Newton-Raphson
FERC	Federal Energy Regulatory Commission
FGD	Flue Gas Desulfurization
GAO	General Administrative Order
GE	General Electric
GHG	Greenhouse Gas
GI	Generator Interconnection
GIA	Generator Interconnection Agreement
GET	Grid Enhancing Technology
GS	General Service
GW	Gigawatt
GWh	Gigawatt Hour
GWP	Global Warming Potential
H_2SO_4	Sulfuric Acid
HDD	Heating Degree Days
HHV	Higher Heating Value
HLF	High Load Factor
HRSG	Heat Recovery Steam Generator
HVAC	Heating, Ventilation and Air Conditioning
IC	Internal Combustion
ICAP	Installed Capacity
IDEM	Indiana Department of Environmental Management
IRA	Inflation Reduction Act
IRP	Integrated Resource Plan
ISO	Independent System Operator

ITC	Investment Tax Credit
IURC	Indiana Utility Regulatory Commission
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt Hour
LCR	Local Clearing Requirement
LDES	Long Duration Energy Storage
LGE/KU	Louisville Gas and Electric/Kentucky Utilities
Li-ion	Lithium-ion
LMR	Load Modifying Resources
LOLE	Loss of Load Expectation
LP	Large Power
LRZ	Local Resource Zone
LRTP	Long-Range Transmission Plan
LSE	Load Serving Entity
MISO	Midcontinent Independent System Operator
MLA	Municipal Levee Authority
MMBtu	One Million British Thermal Unit
MPS	Market Potential Study
MTEP	MISO Transmission Expansion Plan
MVAR	Dynamic VAR Support
MW	Megawatt
MWh	Megawatt Hour
NDA	Non-Disclose Agreement
NERC	North American Electric Reliability Council
NERC MOD	NERC Modeling, Data and Analysis
NOAA	National Oceanic and Atmospheric Administration
NO_x	Nitrogen Oxide
NPDES	National Pollutant Discharge Elimination System
NPV	Net Present Value
NPVRR	Net Present Value Revenue Requirement
NREL	National Renewable Energy Lab
NT	Near-term
NTG	Net to Gross
NYMEX	New York Mercantile Exchange
OBBBA	One Big Beautiful Bill Act
O&M	Operation and Maintenance
ORSANCO	Ohio River Valley Sanitation Commission
OUCC	Office of Utility Consumer Counselor
OVEC	Ohio Valley Electric Corporation
PPA	Purchase Power Agreement
PPT	Parts Per Trillion
PRA	Planning Resource Auction
PRM	Planning Reserve Margin

PRMR	Planning Reserve Margin Requirement
PTC	Production Tax Credit
PV	Photovoltaic
PY	Planning Year
RBDC	Reliability Based Demand Curve
RAN	Resource Availability and Need
RERRA	Relevant Electric Retail Rate Authority
RF	ReliabilityFirst
RFP	Request for Proposals
RIM	Ratepayer Impact Measure
RRA	Regional Resource Assessment
RS	Residential
RTO	Regional Transmission Operator
SAC	Seasonal Accredited Capacity
SAE	Statistically Adjusted End-use
SCGT	Simple Cycle Gas Turbine
SCR	Short Circuit Ratio
SGS	Small General Service
SIGE	Southern Indiana Gas and Electric
SIGECO	Southern Indiana Gas and Electric Company
SMR	Small Modular Reactor
Sox	Sulfur Oxide
SO_2	Sulfur Dioxide
SO_3	Sulfur Trioxide
TDSIC	Transmission, Distribution and Storage System Improvement Charge
T&D	Transmission and Distribution
TOU	Time of Use
TRC	Total Resource Cost
TSR	Transmission Service Request
UC	Utility Cost
UCAP	Unforced Capacity
UCT	Utility Cost Test
V	Volt
VAR	Volt-Amp Reactance
VPP	Virtual Power Plant
VER	Variable Energy Resources
WN	Weather Normalized
ZLD	Zero Liquid Discharge