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AN ALLETE COMPANY

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January 15, 2026

VIA E-FILING
Sasha Bergman
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101-2147

Re: In the Matter of Minnesota Power's Application for
Approval of its 2025-2039 Integrated Resource Plan
Docket No. E015/RP-25-127 and E015/PA-24-198
SUPPLEMENTAL FILING

Dear Ms. Bergman:

Minnesota Power hereby submits this Clean Firm Plan filing to the Minnesota Public Utilities Commission ("Commission") as a supplement to the 2025-2039 Integrated Resource Plan filed on March 3, 2025 in Docket No. E015/RP-25-127. This Clean Firm Plan filing has been developed in response to the Commission's December 10, 2025 Order in Docket No. 24-198, In the Matter of the Petition of Minnesota Power for Acquisition of ALLETE by Canada Pension Plan Investment Board and Global Infrastructure Partners.

Please contact me at (218) 355-3297 or jkuklenski@mnpower.com with any questions regarding this filing.

Respectfully,

Jennifer Kuklenski

Jennifer Kuklenski
Regulatory Strategy and Policy Manager
Minnesota Power
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JK:ah
Attach.
cc: Service List

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of Minnesota Power's	Docket No. E015/RP-25-127
Application for Approval of its	Docket No. E015/PA-24-198
2025-2039 Integrated Resource Plan	**2025 IRP CLEAN FIRM PLAN FILING**

Contents

I. INTRODUCTION

Minnesota Power (or, the "Company") is pleased to submit this "Clean Firm Plan" filing to the Minnesota Public Utilities Commission ("Commission" or "MPUC") as a supplement to the 2025-2039 Integrated Resource Plan ("2025 IRP") filed on March 3, 2025 in Docket No. E015/RP-25-127. This Clean Firm Plan filing has been developed in response to the Commission's December 10, 2025 Order ("December 10 Order") in Docket No. Docket No. 24-198, *In the matter of the Petition of Minnesota Power for Acquisition of ALLETE by Canada Pension Plan Investment board and Global Infrastructure Partners*, which requires Minnesota Power to develop a supplemental Clean Firm Plan filing in consultation with IRP stakeholders.

This Clean Firm Plan ("CFP") filing builds upon the foundation of the 2025 IRP, which outlines the continuation of Minnesota Power's *Energy**Forward*** strategy to achieve a reliable, sustainable, and affordable energy future for Minnesota Power customers while taking historic action to cease coal operations at its generation facilities and meeting the requirements of Minnesota's Carbon-Free Standard ("CFS"). The CFP provides additional analysis and context to further explore resource options that minimize emissions and achieve Minnesota Power's carbon reduction goals and reliability obligations. It is important to note that the alternatives and insights presented in this CFP filing address resource mix considerations to meet the Company's base customer load plan, not the load growth planning scenario that was also included in the 2025 IRP to illustrate how Minnesota Power would serve additional new customers that have the potential to locate in its service territory.

The CFP evaluates four supplemental pathways to the base plan filed in March for replacement energy and capacity to address the requirements of the December 10 Order as Minnesota Power ceases all coal operations for Minnesota Power customers, as proposed in the 2025 IRP, including:

1. **No New Natural Gas Resources ("Wind/Solar/Storage Only")**: This analysis examines the feasibility of meeting Minnesota Power's energy needs through a portfolio of wind, solar, and energy storage resources, without the addition of new

natural gas generation. Nuclear generation was not considered in this pathway due to the nuclear moratorium in the State of Minnesota, as well as the unlikelihood that new small modular reactor ("SMR") nuclear generation could be operational in time to meet Minnesota Power's cease coal operations date in 2035 and the 2025-2039 IRP planning time period included in this docket.[1]

2. **Removing Combined Cycle Natural Gas Resources ("No CC Gas")**: This analysis evaluates the potential to replace the proposed 750 megawatts ("MW") of new combined cycle ("CC") natural gas included in the base plan filed in March with alternative resources.

3. **Reduced Natural Gas Capacity Factor ("Reduced Gas Capacity Factor"):** This analysis explores a potential resource portfolio that reduces reliance on natural gas capacity by decreasing the annual capacity factor of all gas generation to 10 percent.

4. **Minimize Natural Gas Resources ("Minimize Gas")**: This analysis explores a potential resource portfolio that minimizes reliance on CC natural gas capacity while meeting customer electricity needs.

The comparative analyses and pathways in this filing are designed to provide additional perspective and insight for resource planning discussions that align with Minnesota Power's commitment to achieving 90 percent renewable energy by 2035 in compliance with the CFS milestones. The CFP filing also evaluates leveraging the Boswell Interconnector transmission line and other existing infrastructure at the facility to support a lower-emissions energy portfolio, The requirement for clean firm capacity will create opportunities to leverage the $50 million Clean Firm Technology Fund approved

[1] Minnesota Power notes that while the technology for large central nuclear stations is available today, such facilities would need to be built at a size of approximately 2,000-3,000 MW for such a facility to be financially feasible for Minnesota Power. Minnesota Power's 2025 IRP has identified the need for approximately 750 MW to 1,000 MW of firm dispatchable electricity to replace energy currently provided at Boswell. Therefore, a large central station nuclear facility is not realistic for Minnesota Power's current planning needs. Minnesota Power also notes that any nuclear pathway, including SMRs, would require an extension of the Company's established cease coal dates since such technology likely will not be commercially available until 2040 or after. Such a pathway may also result in the need for CFS modification or delay for Minnesota Power.

in Docket No. 24-198 and this filing outlines the proposed procedural steps for leveraging that Fund.

As a critical foundation, the CFP analysis reaffirms Minnesota Power's ongoing dedication to maintaining system reliability, safety and keeping bills as low as possible for customers with a continued commitment to its host communities, and foundational system readiness for the significant transformation away from coal generating resources. As a winter peaking utility, Minnesota Power's CFP evaluation prioritizes planning for reliable service during extreme cold weather events, such as Winter Storm Uri. Ensuring sufficient dispatchable generation is essential to protect customers from the risks of blackouts during extreme cold snaps. After Boswell Unit 4 ceases coal, Minnesota Power will require approximately 750 MW of additional dispatchable resources by the mid-2030s to meet winter peak demand in the base case outlook. Minnesota Power's planning focuses on proven, reliable generation to ensure reliability and safeguards for customer well-being and safety.

Additionally, Minnesota Power recognizes the importance of flexibility and innovation in resource planning to address the evolving energy landscape and the potential for growing customer demand. Integrated planning must ensure that customer energy needs can be continuously met, and a strong foundation is set for the future as the system transitions to cleaner energy sources. Planning must not degrade the power system, but rather enhance and strengthen it so there can be resiliency for what is ahead. The Clean Firm Plan filing reflects the Company's commitment to exploring and comparing diverse pathways for meeting the CFS requirements while continuing to serve the unique needs of its customers and communities. By building on the robust analysis and stakeholder engagement conducted for the 2025 IRP, this supplemental filing provides a thoughtful and transparent approach to evaluating additional pathways to achieving Minnesota Power's long-term reliability and resource needs.

II. BACKGROUND

Minnesota Power operates in a uniquely challenging and dynamic service territory that sets it apart from other investor-owned utilities in Minnesota. The Company's

customer base is distinguished by its concentration of very large industrial customers, including taconite mining operations, paper and pulp mills, and pipeline facilities in a rural setting in Northern Minnesota. These industries account for approximately 74 percent of the Company's total kilowatt-hour ("kWh") sales, making Minnesota Power the utility with the highest load factor in the country. This high-load factor reflects the consistent, 24/7 power requirements of its industrial customers, requiring efficient utilization of the electric system and creating value for all customers. Additionally, over the past several decades, Minnesota Power has incorporated the state's largest amount of industrial demand response capability, further underscoring its innovative history and ability to serve energy-intensive industries reliably and cost-effectively. Unlike other utilities, this significant use of industrial demand response over the last two decades has allowed Minnesota Power to forgo the construction of generation facilities to meet its peak demand.

Minnesota Power's service territory is predominantly rural, spanning communities across 26,000 square miles in northern Minnesota. Unlike other investor-owned utilities in the state, Minnesota Power does not operate nuclear generation facilities and has therefore focused on transitioning its energy portfolio to higher levels of renewable resources. Through its *Energy**Forward*** strategy, the Company has reshaped its power supply from being 95 percent coal-based in 2005 to delivering between 50 and 60 percent renewable energy today—the highest renewable penetration of any utility in Minnesota. Minnesota Power was the first utility in the state to achieve the milestone of delivering 50 percent renewable energy to customers, demonstrating its leadership in clean energy transformation.

This significant transformation has been achieved through the retirement or re-missioning of seven of its nine coal plants, leaving only two coal-fired units at the Boswell Energy Center ("Boswell" or "BEC") to serve the baseload generation needs for customers. These remaining units play a critical role in providing reliable energy to Minnesota Power's energy intensive customers. As the Company advances its cease coal plan, it faces the significant challenge of replacing nearly 1,000 MW of baseload generation and approximately 3 million MWhs of energy need while maintaining reliability standards and reasonable rates for its customers.

The Clean Firm Plan builds on Minnesota Power's 2025 IRP and reflects the Company's commitment to achieving the 2030 and 2035 milestones of CFS, even as it prepares its system for increases in electricity demand and new large power customers. The 2025 IRP marks a historic moment as it outlines a realistic and sustainable path to remove longstanding coal fired baseload energy from its portfolio. While removing this foundation of reliable power supply, Minnesota Power is also taking actions to ensure it achieves compliance with Minnesota's CFS, which requires Minnesota Power to deliver 90 percent carbon-free energy by 2035 and 100 percent by 2040. The critical pathways outlined in this filing build on Minnesota Power's leadership in clean energy transformation while maintaining its commitment to reliability, affordability, regional economic growth, and the communities that have supported Minnesota Power's customer energy needs for decades.

A. STAKEHOLDER ENGAGEMENT

The development of the 2025 IRP was informed by a robust engagement process that began in February 2024, built from Minnesota Power's first-of-its-kind stakeholder engagement implemented in 2019 to inform its 2021 IRP. The 2025 IRP process was enhanced to include a diverse group of participants representing various customer groups, environmental organizations, economic development entities, local government, industry, host communities, Tribal Nations, and others, and provided opportunities for participants to interact outside formal meetings, including tours of Minnesota Power facilities. The process included in-person, virtual, and hybrid meetings that allowed participants to provide input on modeling assumptions, societal cost-benefit analyses, and the impacts of transitioning the power system. The full 2025 IRP engagement process report can be found in Appendix N of the 2025 IRP initial filing.

Participants evaluated the positive and negative impacts of generation facilities on host communities, local economies, workforce, customer costs, public health, the environment, and system reliability. With the support of independent third-party facilitators from Great Plains Institute and Center for Energy and the Environment, Minnesota Power convened three complementary advisory groups to ensure diverse perspectives were incorporated into the planning process:

1. **The Engagement Group**: A broad set of participants convened four times to build a shared understanding of the policy, technology, and socio-economic landscape influencing IRP analyses.

2. **The Societal Advisory Group ("SAG")**: A subgroup of the Engagement Group that convened three times to inform the development of a societal cost-benefit analysis ("SCBA") for Minnesota Power's generation facilities, including Boswell Unit 4 and Hibbard Renewable Energy Center ("HREC").

3. **The Technical Advisory Group ("TAG")**: A subgroup of the Engagement Group that met regularly to discuss modeling assumptions, methodologies, and technical topics such as the Midcontinent Independent System Operator's ("MISO") transmission planning process and seasonal resource adequacy.

Participants emphasized the importance of maintaining reliability, minimizing ratepayer impacts, supporting host communities, and ensuring transparency in the energy transition. It was clear throughout the engagement process that participants were concerned about reliability as Minnesota Power advances its cease coal plan, and that ratepayer impacts of the Company's energy transition be transparent, incremental, and reasonable. Commitment to maintaining jobs in host communities, particularly at Boswell, was also noted as a priority among participants, as was the importance of additional economic opportunities for transitioning communities, such as those associated with large power load growth.

B. 2025 IRP SUMMARY

Minnesota Power's 2025 IRP proposed a preferred plan that balances sustainability, reliability, and affordability while preparing for significant load growth should it emerge on the Company's system. The 2025 IRP includes a Base Plan and the Growth Plan, which account for varying customer demand outlooks.

The Base Plan is designed to meet Minnesota Power's existing customer load while achieving compliance with the CFS, resulting in 95 percent carbon reduction from 2005 levels. Key elements include:

- Ceasing coal in the Company's power supply portfolio by 2030 at Boswell Unit 3 and 2035 at Boswell Unit 4 once firm dispatchable technology is in place.
- Continuing progress on the implementation of 400 MW of new wind energy by 2028, 200 MW of additional utility-scale solar resources, and up to 500 MWh of new energy storage implementation in 2026.
- Expanding renewable resources with up to 400 MW of new wind and 100 MW of new energy storage by 2035.
- Adding 65 to 85 MW of new distributed generation ("DG") solar resources and implementing an EV multi-dwelling unit ("MDU") program to further support customers' electrification needs.
- Maximizing demand side management and customer options by continuing the Company's ECO and energy efficiency programs and creating the necessary tariff mechanisms to acquire at least 100 MW of new long-term demand response capacity by 2028.
- Refueling Boswell Unit 3 with fuel-flexible natural gas by 2030 to leverage existing infrastructure, support host communities, and immediately reduce carbon emissions.
- Adding 750 MW of new CC fuel-flexible natural gas generation by 2035 to replace coal-fired generation at Boswell Unit 4 and ensure system reliability.
- Continuing operations at HREC and exploring biomass as a future solid fuel alternative at Boswell Unit 4.
- Continuing the development and implementation of transmission solutions to address reliability issues related to the Company's cease coal plan.

The Growth Plan is designed to accommodate up to 1,100 MW of anticipated load growth from new industrial customers, reflecting the region's potential for re-industrialization and beneficial electrification. Key elements that would be added to the base plan above include:

- Preparing for up to 750 MW of new peaking generation to support reliability during periods of high demand.

- Increasing renewable implementation to include up to 2,200 MW of wind, 200 MW of solar, and 300 MW of energy storage.
- Collaborating with new industrial customers to incorporate demand response into their operations.

Both plans are designed to achieve 80 percent renewable energy by 2030 and 90 percent by 2035, resulting in a 95 percent reduction in carbon emissions from 2005 levels. Minnesota Power's 2025 IRP also includes a first-of-its-kind $30 million research and development ("R&D") fund to explore emerging clean firm technologies and pilot projects, ensuring the Company remains at the forefront of innovation.

C. CLEAN FIRM PLAN REQUIREMENTS

The December 10 Order requires that Minnesota Power file the Clean Firm Plan supplement to the Company's 2025 IRP, developed consultation with IRP engagement process participants to:

1. *By January 15, 2026, MP shall file an alternative resource plan scenario, henceforth called the "Clean Firm Plan," that takes into account modifications made in this docket and accounts for Minn. Stat. § 216B.1691, subd. 2g (the Carbon Free Standard) in the most cost-effective manner possible. In the IRP docket, MP shall work with stakeholders to develop a Clean Firm Plan that will incorporate changed circumstances on account of the Stipulation and this Order. The Clean Firm Plan shall: Contemplate replacement and/or surplus use of Boswell Interconnector to achieve lower emission scenario*

    a. *Contemplate replacement and/or surplus use of the Boswell interconnection to achieve a lower emission scenario using the externality values that were updated in Docket No. E-999/CI-14-643.*

    b. *Minimize the size and capacity factor of natural gas resources.*

c. *Be developed without the 750 megawatts of new combined-cycle natural gas resources proposed in Minnesota Power's IRP Docket while minimizing the risk of stranded assets for Minnesota Power customers.*

d. *Include clean firm capacity to be funded by the $50 million Clean Firm Fund commitment. The filing shall include details on how Minnesota Power plans to use the Fund including the size and type of the resource(s) to be developed, why the proposed resources are the best use of this Fund, in-service date(s) for proposed resources, and additional funding or financing sources being pursued, as applicable.*

2. *The Clean Firm Plan shall be accompanied by a qualitative description of the scenario and its costs and benefits, as well as a quantitative analysis of how the scenario performs on the factors listed in Minnesota Rules part 7843.0500, subpart*

3. *As ordered in the 2023 IRP, Docket No. E-015/RP-21-33, Minnesota Power shall file in the current IRP Docket amended affiliated interest agreements and updated capacity dedication amounts for the Nemadji Trail Energy Center (NTEC), and parties may analyze whether that amount of NTEC capacity is in the public and ratepayer interest. Minnesota Power shall make the affiliated interest agreement filing by October 15, 2025 in the IRP Docket, and cross-file it in the NTEC affiliated interest agreement docket, No. E-015/AI-17-568.*

On October 15, 2025 and December 19, 2025, Minnesota Power filed updates on the Nemadji Trail Energy Center ("NTEC") Project in the required dockets.[2] Importantly, Minnesota Power's December 19, 2025 update communicated that the Company had terminated its Capacity Dedication Agreement ("CDA") with South Shore Energy and will no longer be an off-taker of the energy from the NTEC Project. In the December 19, 2025 update, Minnesota Power communicated that its need for dispatchable generation is

[2] Reference Docket Nos. E015/PA-24-198, In the Matter of the Petition of Minnesota Power for Acquisition of ALLETE by Canada Pension Plan Investment Board and Global Infrastructure Partners, E015/RP-25-127, In the Matter of Minnesota Power's Application for Approval of its 2025-2039 Integrated Resource Plan, and E015/M-17-568, In the Petition for Approval of the EnergyForward Resource Package.

greater without NTEC as an available resource for customers, as the Company continues with its plans to cease coal operations at Boswell Units 3 and 4.

Since the December 10 Order, Minnesota Power consulted with interested parties, including those from the Department of Commerce, organized labor, members of Minnesota Power's Community Advisory Panels, the Large Power Intervenor Group, and the Clean Energy Organizations. An additional TAG engagement meeting was held on December 17, 2025 to provide participants with an overview of Minnesota Power's additional modeling and analysis conducted since October 3, 2025 and provide participants with an opportunity to ask questions and offer feedback.

During the December 17, 2025 TAG meeting, Minnesota Power reviewed its resource mix, highlighting the importance of dispatchable generation for reliability, and discussed the limitations and environmental impacts of combustion turbines compared to combined cycle gas plants. Minnesota Power also shared insights from its March 2025 filing including the loss of load expectation ("LOLE") analysis and the performance of its system during Winter Storm Uri, underscoring the need for a balanced approach to resource adequacy in the face of increasing system complexity and intermittent renewables. Meeting participants asked for clarification on the distinction between the $50 million Clean Firm Technology Fund and the proposed $30 million R&D fund, included in the initial 2025 IRP filing, and whether specific projects or recipients had been identified for the Clean Firm Technology Fund. They also inquired about the modeling of solar and storage alternatives, the treatment of tax credit timelines for wind and solar, and whether changes in wind generation due to climate change were considered. Additionally, participants asked questions about the role of emerging technologies, such as 100-hour batteries, and whether their commercial availability should be assumed earlier. Minnesota Power responded by clarifying fund purposes, modeling assumptions, and acknowledging areas of ongoing research and regulatory requirements. Appendix B includes the full summary of Minnesota Power's December 17, 2025 TAG meeting, which was facilitated by an independent third-party consultant – Great Plains Institute.

III. CLEAN FIRM PLAN ANALYSIS

As discussed in the 2025 IRP, the key themes underlying the Clean Firm Plan analysis reflects the Company's long-held resource planning principles while meeting current state policy objectives. Minnesota Power's approach to integrated resource planning continues to evolve as the Company gains experience operating a system with increasing levels of intermittent renewable generation and fewer dispatchable resources. In the 2025 IRP, Minnesota Power utilized the EnCompass modeling tool to analyze a range of complex power supply scenarios and identify reliable pathways to achieve the state's CFS milestones. However, the Company's experience — supported by industry trends and third-party research — demonstrates that traditional planning tools alone are no longer sufficient to ensure a robust and reliable plan. Minnesota Power developed reliability criteria that augmented traditional planning tools, like production cost modeling and Load & Capability outlooks, to demonstrate that as the Company reduces carbon in the power supply portfolio the reliable energy service delivered today will not be degraded (additional details on reliability criteria are provided in Appendix K of the Company's 2025 IRP initial March filing).

The Clean Firm Plan analysis builds upon this foundation by examining how different resource pathways, including those with and without CC natural gas generation, impact capacity expansion decisions. The evaluation also considers the benefits of re-using critical infrastructure at Boswell for replacement generation, as well as the additional actions and costs associated with further reducing gas generation.

Minnesota Power is committed to reinvesting in the communities it serves and is coordinating closely with its co-owner, WPPI Energy, on future plans for Boswell Unit 4 and the associated infrastructure. If technologically viable, replacing Boswell Unit 4 with new generation on site would also support local jobs, preserve tax revenue, and benefit the host community that has supported Minnesota Power's customer energy needs for decades. By leveraging existing infrastructure at Boswell, there is minimized risk of stranded assets, a potential to further maximize utilization of the electric system capabilities while reducing cost impacts for customers and supporting community

reinvestment.[3] As final resource planning actions are solidified, the location of the resources needed will consider these factors as specific project plans and site selections are brought forward for Commission review.

From a planning perspective, ceasing coal operations at Boswell Units 3 and 4 presents significant risks to reliability, energy adequacy, system stability, and cost management. To address these risks, Minnesota Power's IRP emphasizes the need for a diverse portfolio that includes dispatchable generation (such as fuel-flexible natural gas), renewables, energy storage, and demand response. The planning is designed to address uncertainties over the 15-year planning horizon, including aging infrastructure, operational and fuel assurance, evolving energy markets, MISO resource adequacy reforms, customer load growth and environmental and policy objectives. Ongoing monitoring and flexibility are essential as technology and regulatory policies continue to evolve.

The Clean Firm Plan analysis reflects Minnesota Power's commitment to resource planning best practices, statutory requirements, stakeholder and community engagement, and continuous improvement. The Company's approach was guided by the following principles:

- **Reliability:** Ensuring 24/7 reliable service for all customers, respecting Minnesota Power's status as a winter-peaking utility with one of the highest load factors in the nation.
- **Customer Cost and Affordability:** Managing costs for all customer classes, with continued focus on the economic health of industrial customers and rural communities.
- **Environmental Impacts:** Achieving meaningful and sustainable decarbonization in alignment with state policy objectives and customer expectations.

[3] There is further discussion on reutilizing existing infrastructure at Boswell included in Appendix A.

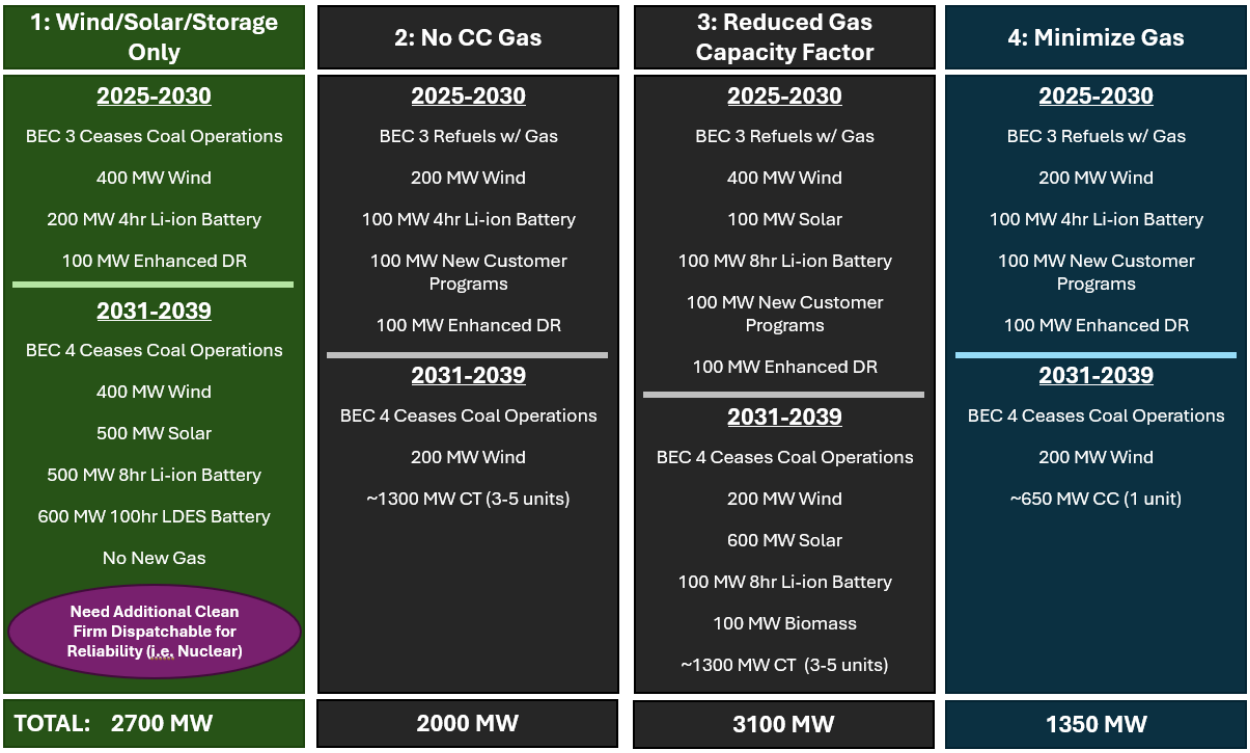
- **Infrastructure and Fuel Efficiency:** How effectively each resource pathway utilizes fuel along with new and existing infrastructure to meet customer needs, especially as the company transitions away from coal-fired generation.

- **System Readiness:** Preparing for future uncertainty and variability, including increased electricity demand, technological change, and evolving market and regulatory conditions.

- **Minimizing Stranded Asset Risk and Efficient Use of Existing Infrastructure:** Recognizing the significant transition underway, considering the amount of infrastructure required to meet the critical needs of the system is paramount. Leveraging and reinvesting in existing assets to minimize transition costs and community impacts.

As discussed above and shown in Figure 1 below, the Clean Firm Plan analysis included four additional pathways to meeting Minnesota Power's anticipated power supply needs for its base customer load outlook, each representing a distinct approach to replacing Boswell Unit 3 and Boswell Unit 4 coal generation and addressing the requirements of the December 10 Order. Each pathway was created utilizing the robust planning analytical methods of the Company's IRP process.

Figure 1. Four Pathways for the Clean Firm Plan Analysis



The Clean Firm Plan analysis included the same supply side and demand side resource alternatives as the initial 2025 IRP filing, including several carbon-free emerging technologies. One new resource alternative was added as an option to select in the capacity expansion analysis – a "surplus/replacement interconnect solar farm" with its capital cost reduced to recognize the benefits of using a surplus interconnect or replacement interconnect at an existing generation facility, such as Boswell[4]. Later in this section is an evaluation of the benefits and anticipated carbon reductions when using critical Boswell infrastructure for new generation that replaces Boswell coal operations. Minnesota Power also incorporated into the EnCompass modeling changes to Production Tax Credit ("PTC") and Investment Tax Credits ("ITC") availability with the passing of the Public Law No. 119-21 ("P.L. 119-21") in early 2025. More information on how P.L. 119-

[4] The "surplus/replacement interconnect solar farm" is a representative solar facility located at an existing generation facility, not an actual project identified by Minnesota Power. Actual capability and cost to locate a new solar farm at an existing generation facility is dependent on availability of suitable land that is in close proximity of the existing generation facility.

21 was incorporated into EnCompass modeling is discussed in Appendix A, which provides the detailed modeling and analysis explanations used to inform this filing.

Each pathway was developed using the EnCompass modeling tool, with scenario assumptions reflecting policy, market, and technology outlooks. The analysis incorporated updated federal incentives (PTCs/ITCs), externality values, and resource cost assumptions, as well as Minnesota Power's enhanced reliability criteria.

As discussed in further detail below, the evaluation and comparison of each pathway was structured around the following key cost/benefit factors, consistent with Minnesota Rules part 7843.0500, subpart 3, and feedback from the IRP engagement process participants: (1) Reliability; (2) Environmental Impacts and Compliance with the Carbon Free Standard; (3) Fuel and Infrastructure Efficiency; (4) Customer Cost Management and Affordability; (5) System Readiness for Future Uncertainty; and (6) Minimizing Risk of Stranded Assets and Reinvesting in Existing Infrastructure.

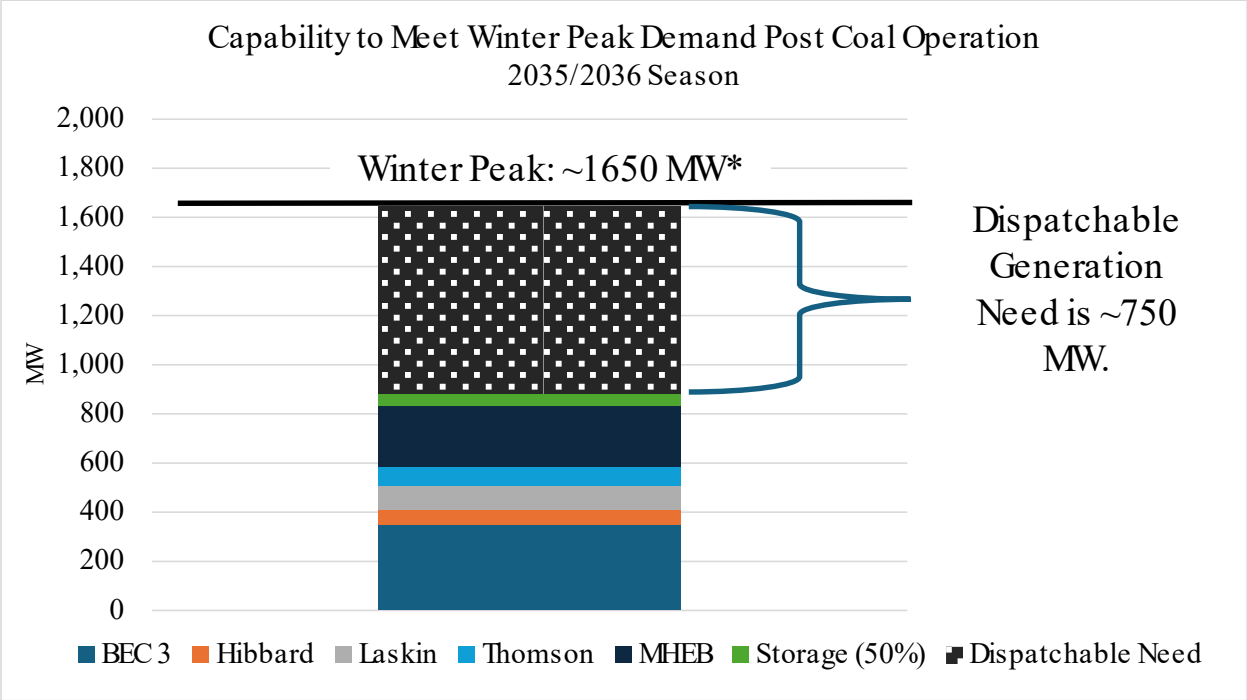
Reliability is the cornerstone of Minnesota Power's resource planning. The Company's reliability criteria go beyond traditional resource adequacy metrics (e.g., accredited capacity, planning reserve margins) to ensure that the generation portfolio can provide 24/7 service under expected operating conditions, including extreme weather events and periods of low renewable output. As Minnesota Power's system transitions away from coal-fired generation at Boswell Units 3 and 4, maintaining system reliability is the Company's highest priority. The evolving resource mix, characterized by a higher penetration of intermittent renewables and fewer dispatchable resources, demands a more sophisticated approach to reliability planning than traditional production cost methods alone can provide.

As a winter peaking utility, Minnesota Power's CFP evaluation compares the performance of each pathway across winter peak demand readiness and extreme event analysis, using Winter Storm Uri as an example. Minnesota Power's ability to reliably meet winter peak demand is critical for the safety and well-being of its customers, especially given the region's extreme cold temperatures that can reach -30 to -50 degrees Fahrenheit for several consecutive days. To prevent potentially devastating impacts from

blackouts during these periods, the Company must maintain a high level of dispatchable generation that can be counted on with certainty. After Boswell Unit 4 ceases coal, Minnesota Power will require approximately 750 MW of additional dispatchable resources to meet an expected base case winter peak demand of 1,650 MW[5] in the mid-2030s, as shown in Figure 2. The dispatchable resource need increases to 1,100 MW if Boswell Unit 3 is not refueled with natural gas after ceasing coal operations in 2030. Because wind and solar generation cannot be relied upon during these critical periods due to their intermittency, Minnesota Power's planning conservatively excludes their contribution in this winter peak demand outlook, ensuring the system is prepared to meet customer needs under the most challenging conditions.

[5] The ~1650 MW system peak is net of customer owned generation, residential distributed generation, and residential/commercial demand response programs.

Figure 2. Minnesota Power's Capability to Meet Winter Peak Demand

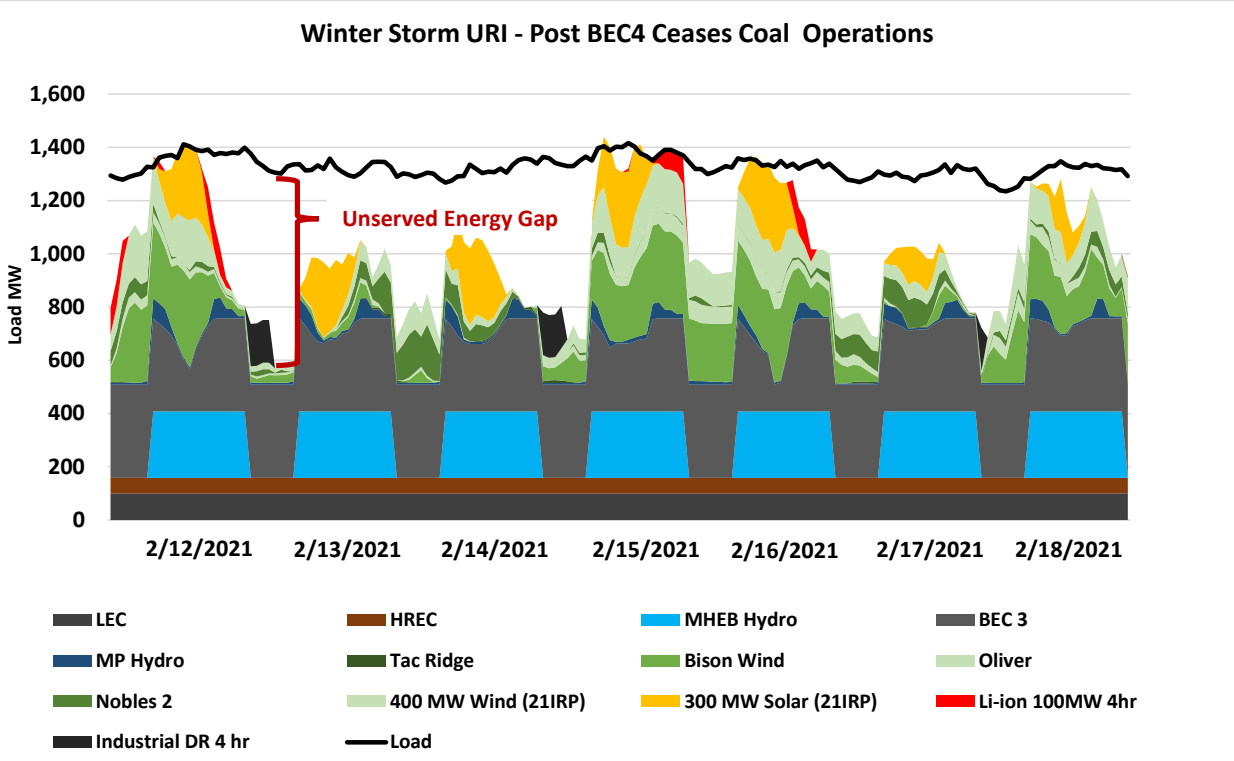


In the initial 2025 IRP filing, Minnesota Power assessed as part of its reliability evaluation how its recommended Base Plan would perform during a Winter Storm Uri-type event, which featured several days of extreme cold, low renewable output, and increased forced outages of traditional resources. This Extreme Event Analysis is crucial for understanding how well different energy portfolios can minimize the risk of unserved energy during periods of critical customer need. The results underscore the importance of maintaining a base generation fleet capable of dispatching continuously for extended periods, with minimal reliance on intermittent renewables. Specifically, after Boswell Unit 4 ceases coal operations, Minnesota Power's analysis showed that a similar event could result in 139 hours of unserved energy and a maximum hourly shortfall of approximately 750 MW.[6] The potential pathways must perform such that unserved energy is minimized to the greatest extent in any future resource portfolio transformation.[7]

[6] Note that the maximum hourly shortfall would increase to 1100 MW if Boswell Unit 3 is not refueled with natural gas after ceasing coal operations in 2030.

[7] Refer to Table 2: Winter Storm Uri Reliability Analysis in Appendix A for the unserved energy results for the pathways.

Figure 3: Energy Supply Performance During Winter Storm Uri with Base Case and Boswell Unit 4 Ceasing Coal Operations



The Company's reliability evaluation also incorporates industry best practices, including LOLE studies. For the 2025 IRP, Minnesota Power engaged PowerGEM, LLC to conduct LOLE modeling, benchmarking the system's risk of unserved energy against the industry reliability standard of 1 day in 10 years. This analysis provides a quantitative measure of reliability risk as the resource mix evolves. The January 9, 2023 Order approving the Company's 2021 IRP, required Minnesota Power to include "a service quality study of its next preferred plan and thoroughly demonstrate how system reliability and resource adequacy will be maintained as it transitions to more intermittent generation resources." This additional LOLE modeling, along with the other reliability criteria, provides the analysis required in this requirement from the January 9, 2023 Order.[8]

Minnesota Power's Clean Firm Plan analysis places a strong emphasis on reducing environmental impacts as the company transitions away from coal-fired

[8] For the results from the LOLE analysis refer to Figure 5: Loss of Load Expectation Modeling Results.

generation at Boswell Units 3 and 4. The environmental evaluation of each pathway focuses on three core areas: annual carbon emissions from energy directly serving customers, compliance with the Environmental Protection Agency's ("EPA") proposed carbon regulations for new gas generation and operational permits, and compliance with Minnesota's CFS. Minnesota Power's analysis confirms that all pathways can achieve compliance with the CFS milestones in 2030 and 2035, with sufficient carbon-free energy added at the lowest cost with the given constraints of each scenario. Table 1 shows the approximate carbon free energy in each pathway to meet CFS requirements for customers.

Table 1. Renewable Energy Used to Meet the CFS Requirement in 2035[9]

	1. Wind/Solar/ Storage Only	**2. No CC Gas**	**3. Reduced Gas Capacity Factor**	**4. Minimize Gas**
2035 CFS Compliance	117%	90%	111%	90%

Developing adaptive plans that can respond to future uncertainty is a core principle of Minnesota Power's integrated resource planning. An adaptive IRP plan is designed to be flexible, able to pivot as conditions change, while maintaining reliability, achieving sustainability targets, and minimizing customer costs. This approach emphasizes the value of resource diversity and sufficient capacity additions to ensure greater reliability at lower cost, and it provides both near-term and long-term strategies to hedge against a range of plausible scenarios, such as unexpected load growth, operational challenges, or delays in new transmission and resource development.

Adaptive planning is informed by EnCompass modeling results, operational realities, anticipated policy changes, and realistic expectations for what Minnesota Power can achieve over the planning horizon. Rather than relying on a single metric, system readiness for future uncertainty is assessed through a combination of observations across key factors, including reliability, environmental impacts, efficiency, and customer cost

[9] The Carbon Free Energy percentage is calculated by dividing total renewable generation production in Minnesota Power's power supply by total energy sales to customers.

management. To support this evaluation, Minnesota Power developed a scorecard using a “stop light” rating system, ranging from green (strong performance) to red (lower performance), to compare each pathway’s readiness for future uncertainty (see Figure 4). This comprehensive approach ensures that the selected pathway can effectively respond to changes and limit risks for both the company and its customers as Minnesota Power transitions away from coal.

The efficiency analysis in Minnesota Power’s Clean Firm Plan evaluation focuses on how effectively each resource pathway utilizes fuel and existing infrastructure to meet customer needs, especially as the company transitions away from coal-fired generation. Minnesota Power places high value on the potential to leverage the existing MISO generator interconnection and associated infrastructure at Boswell as it transitions away from coal generation for its customers. Utilizing this interconnection, either through a MISO surplus interconnection or a generation replacement interconnection, significantly reduces the cost and uncertainty associated with bringing new generation online. The recent value of the interconnection ranges from $85 to $300 million based network upgrade cost assigned to projects located in northwest MISO. Furthermore, this approach supports efficient project development, reducing the typically lengthy MISO interconnection queue process, which can take three to more than four years, providing greater certainty for the transition and project timelines.

As shown in Figure 4, the CFP evaluation provides useful planning insights into how the four pathways perform across key cost/benefit factors. The “Minimize Gas” pathway has the lowest cost profile that meets the reliability criteria as Minnesota power ceases coal generation for customers. The “No CC Gas” pathway has similar reliability performance as the “Minimize Gas” pathway but requires more CT units and infrastructure to achieve the same level of reliability, which drives up costs. The “Reduced Gas Capacity Factor” and “Wind/Solar/Storage Only” pathways have the lowest carbon emissions, although they are challenged on affordability and reliability for customers. The additional analysis shows that the “Minimize Gas” pathway meets the Minnesota CFS requirements with the lowest cost impact to customers, while most efficiently utilizing existing

infrastructure at Boswell and best positions Minnesota Power for system readiness and future uncertainty.

Figure 4. "Clean Firm Plan" Pathways Scorecard

	1: Wind/ Solar/ Storage Only	2: No CC Gas	3: Reduced Gas Capacity Factor	4: Minimize Gas
Reliability Criteria Performance				
Environmental Impacts				
Fuel and Infrastructure Efficiency				
Customer Cost & Affordability				
System Readiness for Future Uncertainty				
Minimize Stranded Asset Risk & Existing Infrastructure Efficiency				
CFS Compliance				

A. PATHWAY 1: NO NEW NATURAL GAS RESOURCES ("WIND/SOLAR/STORAGE ONLY")

Pathway 1 evaluated the possibility of meeting Minnesota Power's energy needs through renewable and storage resources with no additional natural gas resources. This pathway identified the requirement for 2700MW of new resources to be added to Minnesota Power's system. The analysis evaluated the addition of 800 MW of wind, 500 MW of solar, 200 MW of 4hr Li-ion battery storage, 500 MW of 8hr Li-ion battery storage, 600 MW of 100hr long duration energy storage ("LDES"), and 100 MW of demand response resources. The initial 2025 IRP analysis filed last March also evaluated this "Wind/Solar/Storage Only" pathway, which removed new natural gas from the resource

portfolio and assumed the commercial availability of long-duration energy storage at the time of coal retirement.[10]

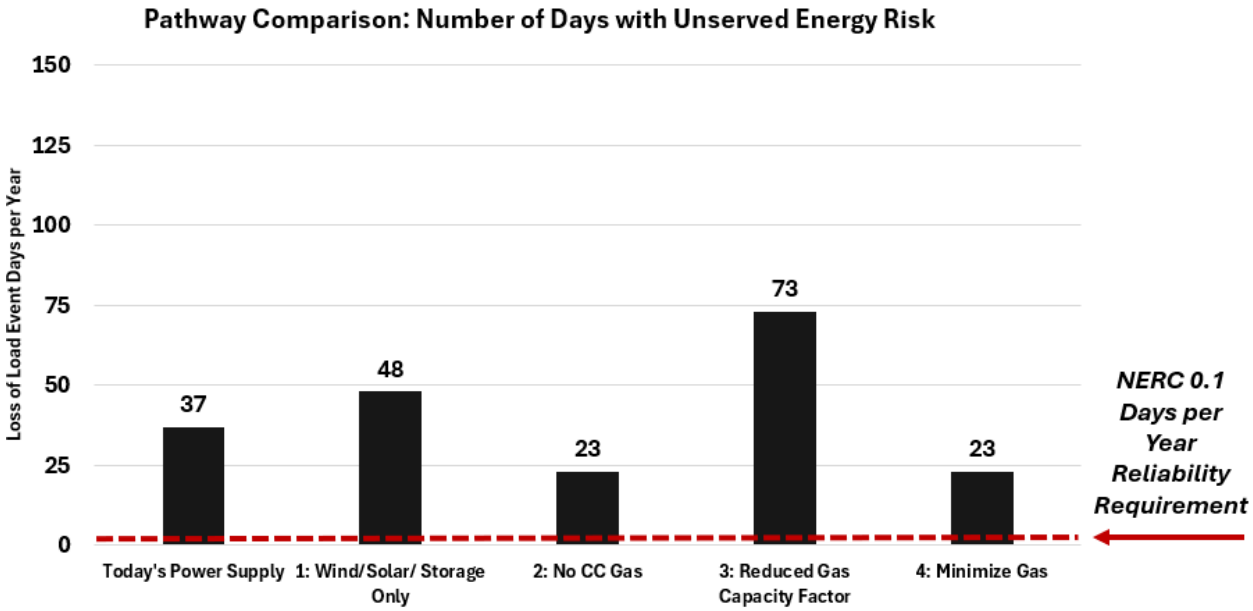
This pathway faces the greatest reliability challenges given the cease coal timeframe commitments and feasibility of building clean firm dispatchable generation (i.e. advanced nuclear generation) by 2035. Even with aggressive additions of wind, solar, and long-duration storage, the system is vulnerable to extended periods of low renewable generation, particularly during winter and summer. The risk of unserved energy is highest in this scenario as the portfolio does not provide enough certainty that storage can be fully charged to reliably meet Minnesota Power's winter peek needs. Relying heavily on batteries introduces higher blackout risk, especially if battery state of charge or event duration limits their effectiveness.

Figure 5 below shows the increase in reliability risk in the No New Natural Gas pathway ("Wind/Solar/Storage Only") when compared to other pathways.[11] For this Pathway to preserve reliability for Minnesota Power customers, approximately 650 MW of additional clean firm dispatchable energy resources would be needed. In this case, new natural gas is eliminated as an alternative and therefore advanced nuclear energy would likely be the next most viable option. However, Minnesota's nuclear moratorium prevents the Company from pursuing this path today as an option for utilizing the existing infrastructure at Boswell. If the Company were able to pursue nuclear generation in a different state, it is unlikely new nuclear generation of needed scale would be able to be developed, permitted, constructed and in-service before 2040. If a nuclear alternative were pursued, the costs to customers would be significantly higher than identified in this analysis and Minnesota Power would likely need to extend its cease coal date for Boswell Unit 4 to accommodate this infrastructure addition.

[10] The "Wind/Solar/Storage Only" pathway was developed in Step 3 "Pathways to Minnesota CFS Analysis" that is discussed on page 40 of Section IV: 2025 Modeling Approach. Also refer to page 20 of Appendix K: Detailed Analysis Section for more detail on the "Wind/Solar/Storage Only" pathway development.

[11] Note that there were 78 hours (46 percent of hours during the event) of unserved energy hours during the Winter Storm Uri event. See Appendix A for additional details.

Figure 5: Loss of Load Expectation Modeling Results[12]



In Figure 5 above, the LOLE results show that Minnesota Power's system has a result that is less than the target of 1 day in 10 years (0.1 for a one-year evaluation), which is expected in this type of analysis because the system is not planned to operate as an island. Minnesota Power's criteria for LOLE results show that a pathway should improve reliability and not degrade the system because relying on MISO and other state's generation resources are becoming less certain. If the LOLE study shows an increase in reliability risk from today's power supply, additional firm dispatchable generation needs to be added to the power supply or gas generation need to operate above the capacity factor limits modeled in the IRP pathways. This evaluation provides critical insight into the reliability strength of each pathway.

When considering carbon emissions of a portfolio, as expected, Pathway 1 delivers the lowest carbon emissions (see Figure 7), but does so at the expense of customer cost and efficiency. Pathway 1 eliminates new natural gas use but will require new transmission and interconnection investments to accommodate high levels of

[12] The LOLE results show that Minnesota Power's system has a worse than the targeted result of 1 day in 10 (0.1 for a one-year evaluation), which is expected because the system is not planned to operate as an island. Minnesota Power's criteria for LOLE results is a pathway should improve reliability and not degrade because relying on MISO and other state's generation resources is becoming riskier.

renewables, in addition to the overbuild of renewable generation and energy storage facilities. This Pathway is the highest cost pathway due to the need for significantly more renewables, storage, and potential new transmission. Accordingly, affordability is a key challenge with this pathway. While Pathway 1 minimizes stranded gas infrastructure, it requires Minnesota Power's system to rely on technologies that are not yet fully developed or commercially proven, which could become stranded assets if their performance is unable to meet customer needs. Pathway 1 is also the least resilient, with limited ability to respond to unexpected events or changes in system conditions.

B. PATHWAY 2: ELIMINATING COMBINED CYCLE NATURAL GAS RESOURCES ("No CC Gas")

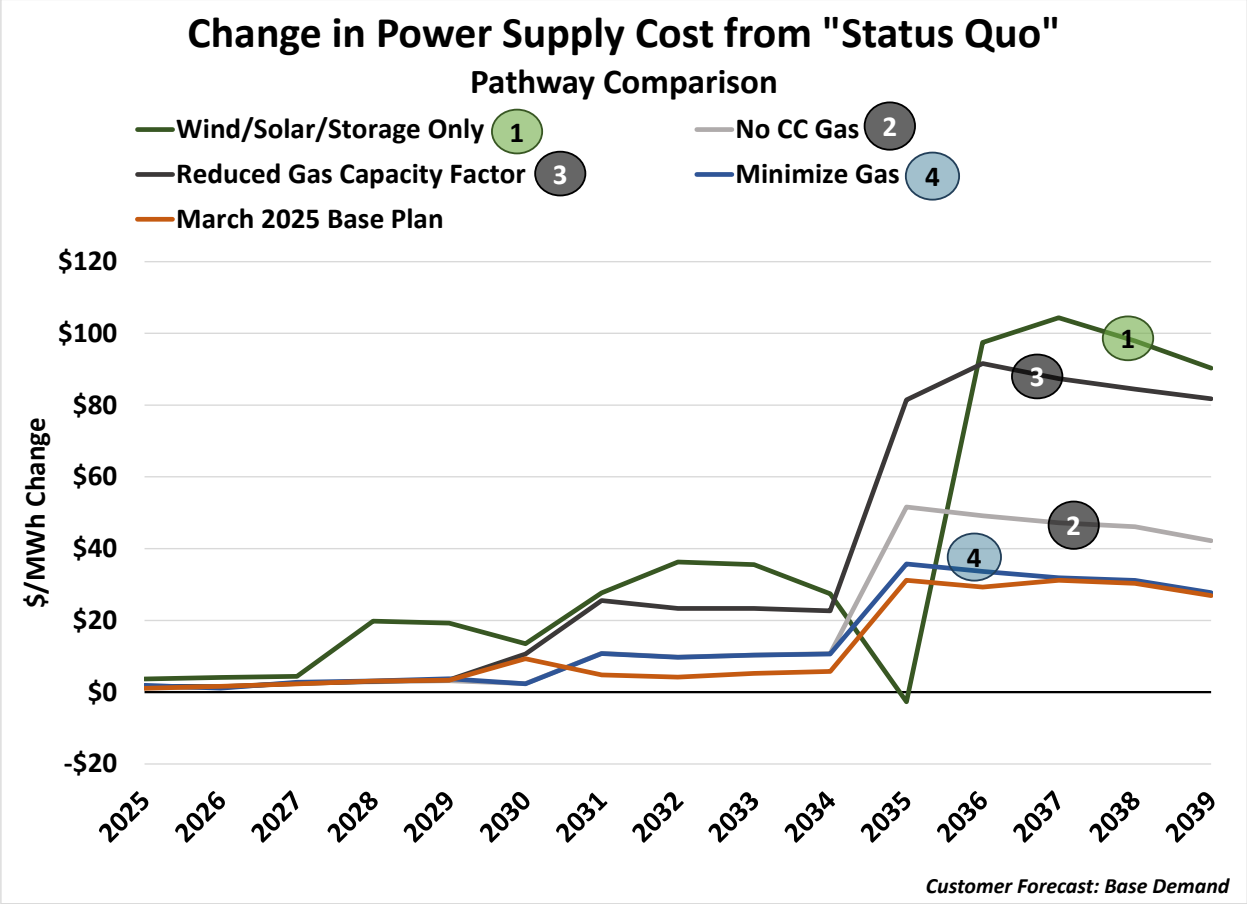
In Compliance with Order Point 13.a.iii in the December 10 Order, Pathway 2 evaluated eliminating the 750 MW of new CC natural gas resources proposed in the 2025 IRP Base Plan, replacing the CC resources with 1300 MW of CT natural gas resources. This pathway requires a total build of 2000 MW of additional resources and would require building approximately 3 to 5 CT facilities and their associated gas supply and transmission infrastructure. This pathway also adds 400 MW of wind, 100 MW of 4h Li-ion battery storage, 100 MW of customer programs, and 100 MW of demand response to meet the overall customer and policy requirements.

Minnesota Power requires a diverse mix of additional resources to replace Boswell Unit 4 baseload coal operations to reduce unserved energy risk during an extreme event and 7x24 operations. The pathways with CC and CT, along with additional wind, solar, and batteries, have the lowest levels of unserved energy risk hours, demonstrated in Minnesota Power's reliability criteria assessment (full results are shown in the Figure 1: Reliability evaluation provided in Appendix A). However, the CT focused option in Pathway 2 carries additional performance risk compared to the CC pathway due to operational limitations from permit constraints and EPA carbon regulations (which typically cap CT resources at 30 to 40 percent capacity factor), as discussed in further detail in the Environmental Impact section included in Appendix A.

A key concern Minnesota Power heard from engagement participants in the IRP process, and from customer survey participants, is the affordability of their energy bill.

The affordability of energy is important to the economic health and wellbeing of community members in northeast Minnesota, especially given the impact Minnesota Power's large industrial customers have on jobs and tax revenue in the towns and counties Minnesota Power serves. Figure 6 shows the change in power supply cost of each pathway from "status quo" as Minnesota Power transitions away from coal. Adding additional CTs for reliability or wind/solar beyond what is required for the CFS results in a higher cost increase for customers.

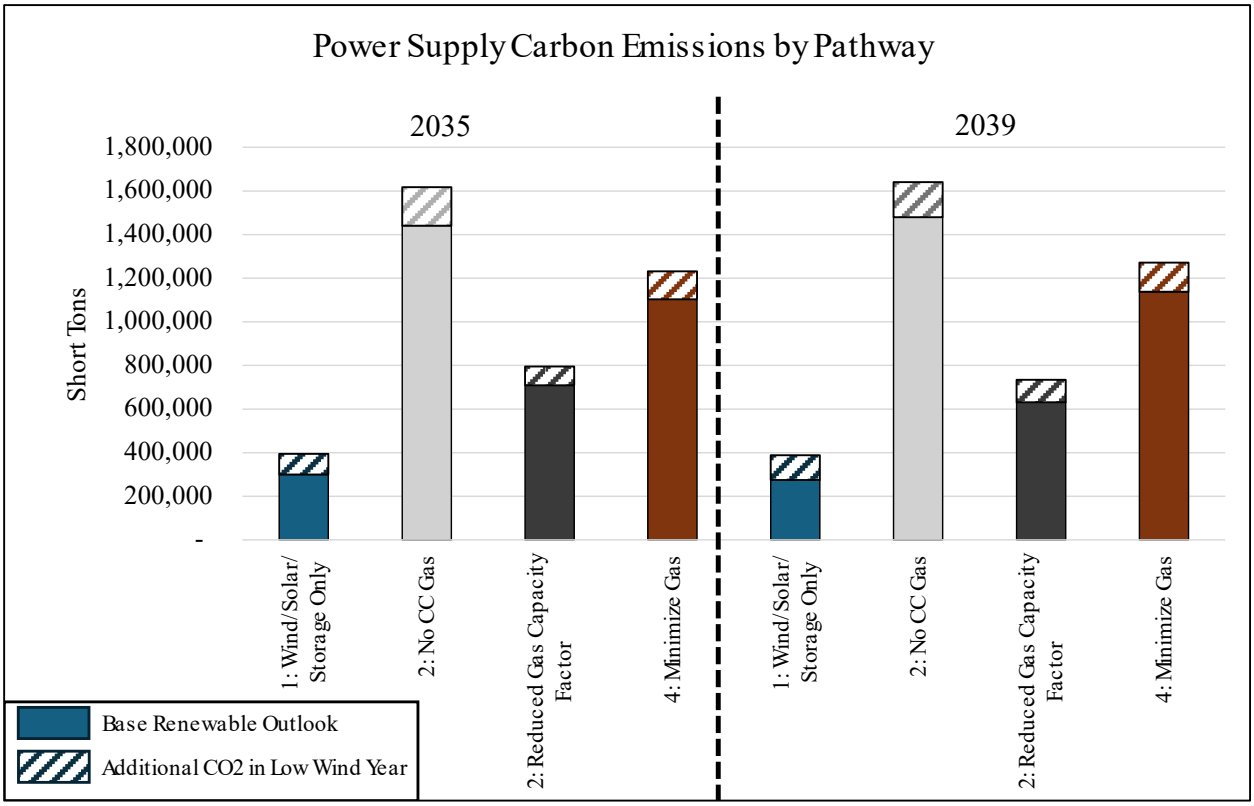
Figure 6: Pathway Power Supply Cost Comparison – Base Demand Outlook



Efficiency of system utilization and implementation is an important consideration for the system transformation underway. The CFP analysis helps provide insights into the alternatives for meeting the core reliability and policy requirements for Minnesota Power customers. From a basic technology standpoint, a CT is less efficient in its fuel usage and emits more CO_2 per MWh when compared to a CC. In a high energy need system like

Minnesota Power's, the CT utilization profile of gas puts significant pressure on infrastructure and emission profiles as it is removing approximately 3 million MWhs of baseload coal fired energy and working to efficiently replace that baseload energy. The additional carbon, infrastructure and fuel system draw all contribute to reduced flexibility in this pathway's portfolio. While this pathway can still meet CFS requirements with sufficient renewable additions, it is at higher customer cost and uses up to 40 percent more gas to meet customer energy needs. Pathway 2 has highest emissions among the pathways with new natural gas.

Figure 7. Projected Annual Carbon Emissions in the Power Supply Associated with Energy Serving Customers



The results, as shown in Figure 7, demonstrate further that CC technology is more efficient and produces less carbon per unit of energy than CTs, and that pathways with reduced gas capacity factors or higher renewable penetration can further lower emissions, though often with tradeoffs in reliability and cost. This is exemplified in a high

energy system and when replacing baseload coal fired energy as is the case in Minnesota Power's cease coal transition plan.

A CT unit requires 40 percent more natural gas to produce the same energy as a CC, increasing fuel costs, carbon emissions and pipeline utilization. CTs are also subject to more stringent operating limits, as discussed above. Pathway 2 therefore results in higher fuel use and lower efficiency which increases costs for customers. Additional CT resource installations are needed to meet reliability criteria, further increasing customer costs.

As stated in the discussion of Pathway 1, Minnesota Power recognizes the value of the Boswell interconnection. Additionally, Boswell's proximity to existing natural gas infrastructure supports the development of new gas generation at the site, eliminating the need for costly new pipeline construction. The company's 2025 IRP Base Plan recommends refueling Boswell Unit 3 with natural gas by 2030 to minimize infrastructure requirements and the Company is actively exploring further optimization of Boswell infrastructure after Boswell Unit 4 ceases coal by 2035. Pathway 2 has a higher risk of underutilization and stranded cost due to the regulatory limits and lower efficiency of CTs. Also, with 1,300 MWs of CT needed for reliability, there is significantly more interconnection and gas supply infrastructure required.

C. PATHWAY 3: REDUCED NATURAL GAS CAPACITY FACTOR ("Reduced Gas Capacity Factor")

In compliance with Order Point 12.a.ii., Pathway 3 evaluated reducing the size and capacity factor for natural gas so that gas generation serves approximately 10 percent of Minnesota Power's energy needs. This pathway requires one of the highest total requirements of new infrastructure to be added, identifying 3100 MW of new resources and customer programs. Additionally, this pathway requires 1300 MW of new clean firm dispatchable generation in the form of 3 to 5 CT facilities to meet reliability criteria.

Limiting all gas generation to a 10 percent capacity factor in the EnCompass modeling forces reliance on renewables and storage to meet approximately 90 percent of customer energy requirements. To meet the Order Point 13.a.ii, Minnesota Power

selected a 10 percent capacity factor limit to identify what changes happen to a power supply portfolio when the natural gas resources are limited. While this reduces emissions, it significantly increases reliability risks unless the gas generation is allowed to operate at a capacity factor greater than 10 percent. Additional batteries and demand response are required in this pathway to fully serve customer energy requirements. Reduced gas capacity factor achieves the lowest carbon emissions among the pathways evaluated with new natural gas resources since gas generation energy production is minimized. However, the need for additional renewables and storage increases customer costs and does not result in reliability criteria being met. Reduced gas capacity factor reduces the overall natural gas usage, but requires significant additional build of gas generation, renewables and storage, and requires significantly more infrastructure than exists today, increasing the risk of stranded assets.

D. PATHWAY 4: MINIMIZE COMBINED CYCLE CAPACITY ("Minimize Gas")

In compliance with Order Point 13.a.ii., Pathway 4 evaluated minimizing combined CC capacity, reducing total CC capacity from 750 MW as proposed in the IRP Base Plan to 650 MW, a reduction of 100MW. Notably, due to the availability of CC technology and the replacement need for firm dispatchable baseload generation on Minnesota Power's system, the Company identified 650 MW as the lowest practical amount of CC natural gas resources needed to preserve reliability for customers. To make up the difference, this pathway proposes adding 100 MW of customer programs to be added. Like the IRP Base Plan, this pathway also adds 400 MW of wind, 100 MW of 4h Li-ion battery storage, and 100 MW of demand response. This pathway requires a total build of 1350 MW, the smallest infrastructure build across all evaluated pathways, and would require the construction of only one natural gas facility. Given the Company's recent decision to no longer be an off taker for capacity from NTEC, the immediate need for dispatchable capacity is more important than ever for Minnesota Power's cease coal plan.

This pathway provides the highest reliability at the lowest cost impact to customers, with modern CC units offering dispatchable, high-capacity-factor energy that can backstop intermittent renewables across multiple operating scenarios. The flexibility and efficiency of CC technology minimizes the risk of unserved energy, especially during

winter peaks and prolonged low-renewable periods. Additionally, CC technology is significantly more efficient than CTs, where a CT produces the same amount of energy with using 40 percent more natural gas – an important advantage during periods of constrained gas supply, as CCs can generate more energy and make better use of limited fuel resources. Furthermore, a modern CC is significantly more efficient than refueling BEC unit 4 with natural gas. The BEC unit 4 boiler is very large (similar in size to a 17 story apartment building), even compared to BEC Unit 3, requiring large volumes of natural gas to heat the steam required for generation. When compared to a modern CC, refueling BEC unit 4 with natural gas requires nearly double the volume of natural gas which results in doubling the carbon emissions as compared to a CC. The reduced CC capacity pathway offers significant carbon reductions compared to coal generation, with CT units emitting 40 percent more CO_2 than CCs per unit of energy. Like all pathways evaluated in the Clean Firm Plan analysis, Pathway 4 supports compliance with the 2030 and 2035 CFS milestones.

The key comparison between CC and CT gas technologies demonstrates CC technology as significantly more efficient, generating approximately 40 percent more energy from the same amount of natural gas than CTs. This is because CC technology captures exhaust heat to produce additional steam-generated electricity, whereas CTs release exhaust heat directly into the atmosphere (Appendix A includes diagrams and further discussion of the comparison between CC and CT technologies). Because of this, Pathway 4 would allow Minnesota Power to maximize the value of existing pipeline infrastructure, fuel use and minimize the need for new gas delivery investments.

The CC natural gas units can operate above 40 percent capacity factor, which means they offer greater operational flexibility than CT units and are better positioned to meet both reliability and environmental requirements. The CC unit technology can be further decarbonized through fuel conversions, and their operational flexibility supports integration of emerging carbon free enabling technologies.

Efficient use of natural gas supply and pipeline infrastructure is critical for keeping customer costs reasonable and reducing the need for new infrastructure investments. CC

units require less firm gas supply and make better use of pipeline capability, which is especially important during winter peak events when natural gas demand and prices can spike dramatically. For example, during extreme events like Winter Storm Uri, one CC unit could save customers millions of dollars in fuel costs compared to multiple CT units due to their higher efficiency and put less strain on the natural gas infrastructure system.

Additionally, CC technology maximizes the energy generation potential at existing interconnection points, such as at Boswell, and is not subject to the same operational caps as CTs, which are limited by environmental permits and EPA carbon regulations. The analysis also tracked the volume of natural gas needed in each pathway, showing that CC pathways use less gas to reliably serve customers, particularly in years with low wind production (see Figure 10 in Appendix A). Overall, the efficiency evaluation demonstrates that pathways utilizing CC technology best optimize fuel use and infrastructure, supporting reliability and affordability as Minnesota Power transitions to a cleaner energy mix.

E. PATHWAY EVALUATION SUMMARY

The CFP evaluation provides useful planning insights into how the four pathways performed across key factors used in integrated planning, to include protecting affordability for customers, continuing to make progress in meeting CFS, and ensuring the future reliability of the energy grid. As Minnesota Power takes the critical step to remove coal from its system, there are significant energy and reliability needs that must be addressed. The analysis highlighted the importance of having a diverse power supply that adds modern dispatchable generation to replace coal operations. The evaluation demonstrates that Pathway 3 (“Reduced Gas Capacity Factor”) and Pathway 1 (“Wind/Solar/Storage Only”) have the lowest carbon emissions, although they are challenged on affordability, flexibility and reliability. Pathway 4 (“Minimize Gas”) has the lowest cost profile that meets the reliability criteria as Minnesota Power ceases all coal operations. Pathway 2 (“No CC Gas”) has similar reliability performance but requires more CT units and infrastructure to achieve those levels of reliability resulting in a higher cost for customers. Overall, the CFP evaluation highlights the importance of considering resource efficiency and diversity in managing customer costs as Minnesota Power

transitions to a cleaner energy mix and takes on the historic task of ceasing coal operations. The optimal pathways and activities should meet the 2035 CFS milestones with the lowest cost impact to customers, while efficiently utilizing existing energy and natural gas infrastructure in a way that positions Minnesota Power's system for the future.

III. $50 MILLION CLEAN FIRM TECHNOLOGY FUND

A. OVERVIEW OF THE CLEAN FIRM TECHNOLOGY FUND

The $50 million Clean Firm Technology Fund was an item included in a broad settlement agreement, first made between the Department and the Company and later supported by other Parties to Docket No. E015/PA-24-198. On August 28, 2025 the Commission asked a series of questions concerning the Clean Firm Technology Fund, which the Company responded to through PUC IR 0013 on September 4, 2025. As stated in that IR response, in the settlement agreement the definition for a project's eligibility for this fund differs from the statutory definition in Minn. Stat. § 216B.1691, subd. 1(b) and is specific for the use of this fund only. The fund will receive initial funding in 2026 and be fully funded by 2030 and available for use for efforts to comply with the 2040 Carbon Free Standard.

The Company has not identified specific projects in the first five years of this IRP for which it would request support from the Clean Firm Plan, particularly as the technology that would meet the eligibility listed in the fund (which is carbon free and also able to provide energy continuously for 50 hours or more) is still evolving. Minnesota Power is continuously monitoring emerging technology and evaluating the effectiveness of clean firm technology options for customers. It is the Company's expectation that projects supported by the Clean Firm Technology Fund would be identified through future IRP processes.

The settlement agreement is clear that the Clean Firm Technology Fund is an investor funded account that is fully non-recoverable through customer rates. It is Minnesota Power's intent that this fund will operate within existing Commission

processes, including but not limited to IRPs, advanced determination of prudency or resource acquisition proceedings.

The Company explained through its response to PUC IR 0013, the procedure by which a project could be recommended for use of the Clean Firm Technology Fund. A project would be proposed by Minnesota Power through a regulatory petition for approval. The petition would identify the total cost of the project and why approval of it would be in the public interest. In that regulatory request, the Company would also request support for an eligible project from the Clean Firm Technology Fund. If the Commission were to approve both the project and that the Clean Firm Technology Fund would support it, specific Commission-approved amounts from the Clean Firm Technology Fund would be used to write down the cost of projects for customers and be deducted from the overall cost recovery request in subsequent proceedings.

B. EMERGING TECHNOLOGY AND EVOLVING CUSTOMER PROGRAMS

Through its current 2025 IRP, Minnesota Power screened several technologies and did not identify any specific projects that meet the eligibility criteria of this fund, requiring carbon free resources to be continuously dispatched for 50 hours or more, as part of least cost planning principles identified in Minn. Stat. § 216B.2422, subd. 2. However, the Company is actively exploring and pursuing emerging technologies and customer programs that could help it meet the requirements of the Carbon Free Standard. This section will highlight a few of those categories of exploration.

One area of exploration for Minnesota Power is how leveraging more distributed energy and customer programs can help support system needs. These programs would evaluate the potential to engage Minnesota Power's residential and commercial customers, which together consist of approximately 600 MW of electric needs (approximately 300 MW of residential customers and 300 MW of commercial customers), to help reduce the Company's usage profile from the bulk system.

As a current example of a pilot project on the distribution system intended to evaluate how non-wires alternatives can ensure efficient utilization of the grid, Minnesota

Power is currently implementing a 2.5 MW/5 MWH battery energy storage system near Kerrick, Minnesota, a small town on Highway 23 south of Duluth. This proposed pilot project will support reliability of the distribution system by maintaining energy supply to the city of Kerrick and eliminating the need to rebuild almost 30 miles of aging 46kV infrastructure, thereby avoiding capital costs of around $15,8 million.[13]

Additional activities in customer programs at the distribution level that the Company could pursue include:

- Advanced readiness of Minnesota Power's system to accommodate additional distributed technology, like investing in innovative metering applications and software solutions.

- Extension and augmentation of current customer programs like those that encourage demand response or installation of heat pumps. Minnesota Power's 2025 Integrated Distribution Plan further outlines opportunities to increase the amount of flexible load programs available to customers through its Energy Conservation and Optimization ("ECO") portfolio.

- Expansion of projects selected within the Distributed Solar Energy Standard process.

- For the bulk energy system, Minnesota Power continues to monitor the advancement of new innovative utility scale generation technology. The Company's 2025 IRP screened over a dozen new technologies[14] and will continue to identify opportunities for those that are gaining technological and commercial viability and can advance the goals of its system. Minnesota Power will continue to:

[13] Minnesota Power's 2025 Integrated Distribution Plan. Docket No. E015/M-25-140.
[14] Reference Appendix D: Future Resource Options and Appendix K: Detailed Analysis Section in the 2025 IRP initial filing for more information about the technologies Minnesota Power evaluated in its 2025 IRP analysis.

- Monitor and support emerging utility scale options under development, and
- Pursue alternatives and pilots to advance technology readiness in the next IRP.

Given the Company's unique customer mix, efforts in Industrial decarbonization remain an important area of focus, including enhanced demand response programs for its largest industrial customers and identifying opportunities for electrification in that sector. In 2023, Minnesota Power supported an industrial customer's application for a grant from the Department of Energy to support a mine truck electrification project but unfortunately, the project was not selected for an award. However, Minnesota Power continues to explore opportunities to partner with its largest customer on decarbonization efforts.

V. CONCLUSION

Minnesota Power appreciates the opportunity to provide additional information to supplement the 2025 IRP filing and address the Commission's requirement to submit the Clean Firm Plan, as required by the December 10 Order. The Company is also grateful for the ongoing engagement with stakeholders, agencies, advocates, and Tribal Nations in support of Minnesota Power's efforts to develop a thoughtful plan to meet the future energy needs of the Company's customers and communities. The 2025 IRP reflects Minnesota Power's commitment to transparency, collaboration, and thoughtful planning during this historic energy transition. By leveraging stakeholder input and innovative resource strategies, Minnesota Power is well-positioned to achieve compliance with the CFS while continuing to deliver reliable, affordable, and increasingly clean energy to its customers.

The CFP evaluation offers a comparison of how four pathways perform across key cost/benefit factors, including winter peak demand readiness and extreme event analysis. As a winter peaking utility, Minnesota Power's CFP evaluation prioritizes reliability and customer safety during the most extreme winter weather events. Minnesota Power's

system will require approximately 750 MW of additional dispatchable resources to meet an expected winter peak demand of 1,650 MW to meet its cease coal date at Boswell Unit 4 in 2035. In order for Minnesota Power to meet its cease coal dates in 2030 and 2035, the Company needs certainty in 2026 on energy and capacity resources to replace coal generation on its system by 2030 and 2035. Minnesota Power looks forward to working collaboratively with stakeholders throughout this ongoing IRP proceeding.

Dated: January 15, 2026

Respectfully submitted,

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ANALYSIS APPENDIX

This Appendix contains the support and approach used to inform the evaluation included in the Clean Firm Plan ("CFP") filing. The Appendix is organized in the following sections:

- A: Pathway Development for the CFP Evaluation
- B: Pathways Tradeoffs – Cost and Benefit Evaluation
- C: Capacity Expansion Analysis Results for CFP Evaluation
- D: Detailed Comparison of Pathway Cost

Integrated Resource Planning best practices continue to evolve as utilities gain experience with planning for and operating a system with high penetration of intermittent generation and fewer dispatchable generation resources to ensure a plan is reliable, affordable, and sustainable. In the 2025 IRP analysis, the Company used the EnCompass modeling tool to analyze complex power supply scenarios under various assumptions, while identifying reliable pathways to achieve the Carbon Free Standard ("CFS") milestones. While developing the 2025 IRP plans, Minnesota Power observed in its own evaluation, along with observed trends across other utility IRPs and third-party research, that a traditional planning tool like EnCompass on its own is no longer sufficient to develop a robust plan. Minnesota Power developed a Reliability Criteria that augmented traditional planning tools, like production cost modeling and using a capacity adequacy approach such as Load & Capability, to demonstrate that as the Company reduces carbon in the power supply the reliable energy service delivered today will not be degraded. Please refer to Appendix K: Detailed Analysis Section for more details on the Reliability Criteria evaluated in the March 2025 IRP filing. This section will discuss how the CFP evaluation impacts the capacity expansion analysis, along with a side-by-side comparison on pathways to meet Minnesota Power energy needs. Also discussed in this Appendix are the benefits of re-using critical infrastructure for replacement generation.

Ceasing coal operations at Boswell Energy Center (or, "Boswell" or "BEC") units 3 and 4 poses significant planning risks to reliability, energy adequacy, system stability, and cost management, while having considerable economic impacts on local communities. To mitigate these risks, Minnesota Power emphasized in the initial 2025 IRP filing the need for developing a replacement supply that includes a diverse portfolio with dispatchable generation, renewables, energy storage, demand response, and commitment to the BEC host community with re-investment opportunities. Furthermore, the plan was developed to help position the portfolio for uncertainty the company will face over the IRP 15-year study period such as, existing aging infrastructure, operational and fuel assurance, tightening and more volatile energy markets, MISO resource adequacy reform, customer load growth, and environmental and policy risks. Continuous monitoring and flexibility are needed as advancements in emerging technologies and regulatory policy evolve to ensure a reliable, sustainable, and affordable transition from coal fired generation.

The initial 2025 IRP analysis and filing included studying replacing BEC units 3 and 4 coal operations with only wind, solar, and energy storage (referred to as the

"Wind/Solar/Storage Only" pathway). This pathway development assumed that emerging long duration energy storage technology would be commercially available at the time coal operations were ceased. This analysis highlighted the significant reliability challenges when relying solely on wind, solar, and energy storage to meet Minnesota Power's core energy needs. Compared to the recommended 2025 IRP Base Plan, new gas generation paired with batteries and renewables provided better reliability, reduced unserved energy risk during winter storm events, and provided better diversity during prolonged periods of low renewable output. Overall, this robust analysis filed in March 2025 underscores the importance of maintaining a diverse energy portfolio when working to meet the carbon free standard requirements, including dispatchable gas generation, to ensure reliability and minimize unserved energy risks.

The next section will walk through the results from the CFP evaluation and the additional pathways identified. The comparison focuses on key risk areas that must be addressed when ceasing coal operations at BEC units 3 and 4 along with addressing the IRP factors listed in Minnesota Rules part 7843.0500, subpart 3: 1) Reliability, 2) Environmental, 3) Efficiency, 4) Customer Cost Management, and 5) System Readiness for Future Uncertainty. After this discussion, the results of the EnCompass capacity expansion analysis and pathway cost comparison results are provided.

CFP Evaluation Power Supply Comparison Evaluation

This tradeoff analysis is a detailed review of the pathways identified in CFP evaluation, based on the extensive multi-step planning evaluation that was used in the initial 2025 IRP filing. The analysis included evaluating different alternatives for replacing coal operations at BEC units 3 and 4, which included performing capacity expansion analysis where combined cycle (or, "CC") generation was excluded as an option and determining the impacts of decreasing the capacity factors of gas generation. The resulting Encompass cases were evaluated through Minnesota Power's reliability criteria, and additional generation was added if needed to meet the established reliability criteria. As with the original IRP analysis, the EnCompass modeling incorporated the Minnesota planning requirements for carbon regulation and environmental cost, along with meeting the orders in the ALLETE acquisition proceeding[1] and complying with the CFS. To accomplish this comparison, the Company developed new pathways that varied the level and type of gas generation (i.e. combined cycle or combustion turbine) and compared them to each other and the "Wind/Solar/Storage" pathway from the initial 2025 IRP filing. This comparison focused on the tradeoffs, costs and benefits of each pathway across key risk areas identified by Minnesota Power and the factors outlined in Minnesota Rules part 7843.0500, subpart 3.

A. Pathway Development for CFP Evaluation

Minnesota Power utilized many of the same steps from the multi-step planning evaluation used in the initial 2025 IRP analysis along with a few additions to develop new pathways that minimize gas generation, excluded some gas technologies, and that meet

[1] Docket No. E015/PA-24-198 In the Matter of the Petition of Minnesota Power for the Acquisition of ALLETE by Canada Pension Plan Investment Board and Global Infrastructure Partners

the CFS requirements. The robust analysis process used in the 2025 IRP needed to be amended to perform the analysis required to complete the CFP evaluation. The CFP evaluation used the following steps shown in bold font for this evaluation (note the non-bolded items were utilized in the March 2025 filing):

1. **"Traditional Capacity Expansion Analysis" – Identify which resource alternatives should be added to the power supply. This includes resource alternatives that replace BEC units 3 and 4 coal capacity and energy output at the cease coal commitment dates from the approved 2021 IRP.**
2. "Pathways for Industrial Demand Scenarios" – Identify the resource alternatives mix needed to meet multiple demand forecasts.
3. **"Pathways to Minnesota CFS Analysis" – Identify which additional carbon-free resource alternatives are needed to augment the initial 2025 IRP expansion plan established in Step 1 and 2 to meet Minnesota's CFS requirements. This step also explores how Minnesota Power's system and resource mix could operate if only wind, solar, and energy storage are available to augment the energy portfolio to meet the loss of baseload supply and the CFS Requirements**
4. "Emerging Technology Capacity Expansion Analysis" – Identify how the capacity expansion analysis changes if emerging technologies, which are not expected to be commercially available at the time of the BEC units 3 and 4 cease coal dates, were available.
5. "2025 Plan Selection" – Finalize two preferred plans, one for the base customer forecast ("Base Plan") and one for the +1100 MW Growth Scenario ("Growth Plan").
6. **"2025 Plan Reliability Criteria Evaluation" – This is the core analysis that evaluates the resiliency and reliability of the pathways and identifies if any modifications are needed to improve resiliency and reliability**.
7. "2025 Plan Energy and Capacity Outlook" – Detailed review of Minnesota Power's 2025 Plan
8. **NEW: "Pathways Tradeoffs – Cost and Benefit Evaluation". A detailed comparison of the tradeoffs, cost and benefits of each pathway, across several key performance metrics developed by Minnesota Power**

The CFP evaluation included the same supply side and demand side resource alternatives as the initial IRP, including several carbon-free emerging technologies. One new resource alternative was added as an option to select in the capacity expansion analysis – a "surplus/replacement interconnect solar farm" with its capital cost reduced to recognize the benefits of using a surplus interconnect or replacement interconnect. Later in this section is an evaluation of the benefits and anticipated carbon reductions when using critical BEC infrastructure for new generation that replaces BEC coal operations. Minnesota Power also incorporated into the EnCompass modeling changes to PTC and

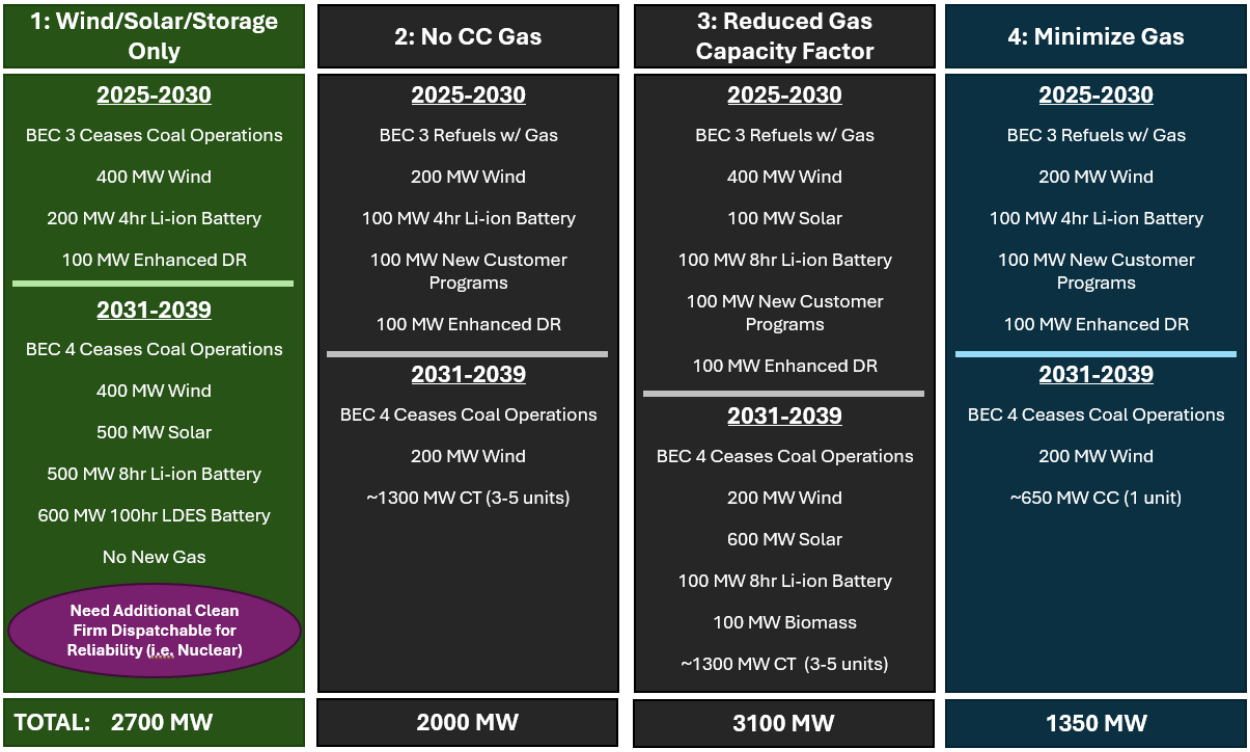
ITC availability with the passing of the Public Law No. 119-21 ("P.L. 119-21"). More detail regarding how P.L. 119-21 was incorporated into EnCompass modeling is discussed later in the capacity expansion analysis results section.

Minnesota Power created pathways that met the requested criteria of the CFP; utilizing varying levels of gas generation and energy storage to meet reliability criteria and the CFS, including pathways without the development of 750 MW of new CC generation and some that limited the capacity factors for gas generation (see Figure 1 below). The development of these pathways was informed by updated capacity expansion analysis that includes EnCompass modeling that didn't allow CC generation as an alternative to meet customer needs, minimized natural gas generation capacity factors, and used the externality values updated in Docket No. E-999/CI-14-643.[2]

In the "Minimize Gas" pathway, additional batteries and customer programs were added to meet the reliability criteria and to replace the 100 MW reduction in CC from the Base IRP Plan. To meet the Docket No: E-015/PA-24-198 order point 13.a.ii "Minimize…capacity factor of natural gas resources", the "Reduced Capacity Factor" pathway includes higher levels of wind, solar, storage, batteries, and new biomass generation to replace gas generation when capacity factors are decreased to 10 percent. The "No CC Gas" pathway evaluates replacing the proposed 750 MW CC with alternative resources that exclude CC technology, including combustion turbine ("CT") technology as a replacement option. The "Wind/Solar/Storage Only" pathway was carried forward from the initial 2025 IRP analysis filed in March 2025. Below is a summary of the resource additions included in each pathway evaluated in the CFP evaluation, referred to as Step 8: Pathways Tradeoffs – Costs and Benefits Evaluation.

[2] Note that Minnesota Power's initial capacity expansion analysis in the March 2025 filing used the same externality values updated in Docket No. E-999/CI-14-643.

Figure 1: Four Pathways for the CFP Analysis



B. Pathways Tradeoffs – Cost and Benefit Evaluation

The following analysis was designed to identify the cost and benefits of reducing reliance on gas generation and selecting different gas generation technologies (i.e. CT vs CC). Step 8: Pathways Tradeoffs – Cost and Benefits Evaluation is a comparison focused on the tradeoffs, costs and benefits of each pathway across key factors identified by Minnesota Power and the factors outlined in Minnesota Rules part 7843.0500, subpart 3. The key factors and risk evaluated were:

1. *Reliability*: Ensuring 24/7 reliable service for all customers, especially given Minnesota Power's status as a winter-peaking utility with one of the highest load factors in the nations.
2. *Environmental Impacts*: Achieving meaningful and sustainable decarbonization in alignment with state policy objectives and customer expectations.
3. *Infrastructure and Fuel Efficiency:* How effectively each resource pathway utilizes fuel along with new and existing infrastructure to meet customer needs, especially as the company transitions away from coal-fired generation.
4. *Customer Cost and Affordability*: Managing costs for all customer classes, with continued focus on the economic health of industrial customers and rural communities.

5. *System Readiness:* Preparing for future uncertainty and variability, including increased electricity demand, technological change, and evolving market and regulatory conditions.
6. *Minimizing Stranded Asset Risk and Efficient use of Existing Infrastructure:* Recognizing the significant transition underway, considering the amount of infrastructure required to meet the critical needs of the system is paramount. Leveraging and reinvesting in existing assets to minimize transition costs and community impacts.

Factor 1: Reliability

Minnesota Power places a strong emphasis on its responsibility for maintaining system reliability as the company transitions away from coal generation. The reliability criteria evaluation is a key component of the planning process, ensuring that the generation portfolio can meet customer needs under all operating conditions, and North American Reliability Corp ("NERC") reliability standards. The traditional resource adequacy construct, relying on accredited capacity and planning reserve margins to demonstrate reliability, is no longer sufficient on its own to ensure a 7x24 reliable energy supply for customers. As more reliance is placed on intermittent renewables to provide reliable energy during all types of operating conditions, it is important to understand what amount and type of additional generation is needed on the system, especially during extreme events where impacts on residential and commercial customers can be devastating. The January 9, 2023 Order approving the Company's 2021 IRP, required Minnesota Power to include "a service quality study of its next preferred plan and thoroughly demonstrate how system reliability and resource adequacy will be maintained as it transitions to more intermittent generation resources." Minnesota Power's reliability criteria evaluation ensures that the transition to a cleaner energy mix does not compromise the integrity of the electric system, as detailed in Appendix K: Detailed Analysis Section filed with the initial 2025 IRP. The CFP evaluation compares the performance of each pathway across the following four reliability criteria:

- Winter Peak Demand Readiness
- Extreme Event Analysis
- Loss of Load Expectation Study
- Energy Adequacy

The "Minimize Gas" and "No CC Gas" pathways met all reliability criteria requirements. The "Reduced Gas Capacity Factor" and "Wind/Solar/Storage" pathways showed elevated levels of unserved energy risk, which was evident in the results from the Loss of Load Expectation ("LOLE") Study and Energy Adequacy reliability criteria. The "Reduced Gas Capacity Factor" pathway would meet the reliability criteria if peaking generation was allowed to operate at a capacity factor greater than the 10 percent limitation. The "Wind/Solar/Storage Only" pathway requires additional clean firm dispatchable generation (i.e. nuclear) to meet the reliability criteria. Nuclear generation while currently a clean firm, dispatchable technology remains banned for state planning purposes.

However if able to be considered it is important to note that central station nuclear facilities are built at significantly large scales (typically 2,000 to 3,000 MW) to be economically feasible, therefore for the needs identified in the pathways in this filing, Minnesota Power would investigate small nuclear reactor ("SMR") technology to fulfill the clean firm dispatchable requirements identified to ensure the "Wind/Solar/Storage Only" pathway meets reliability criteria. However, SMR technology isn't expected to be commercially available until 2040 or after. This would likely require an extension of Minnesota Power's cease coal dates at Boswell for the "Wind/Solar/Storage Only" pathway. The following is a broader discussion of the results from the reliability criteria evaluation for the pathways included in the CFP.

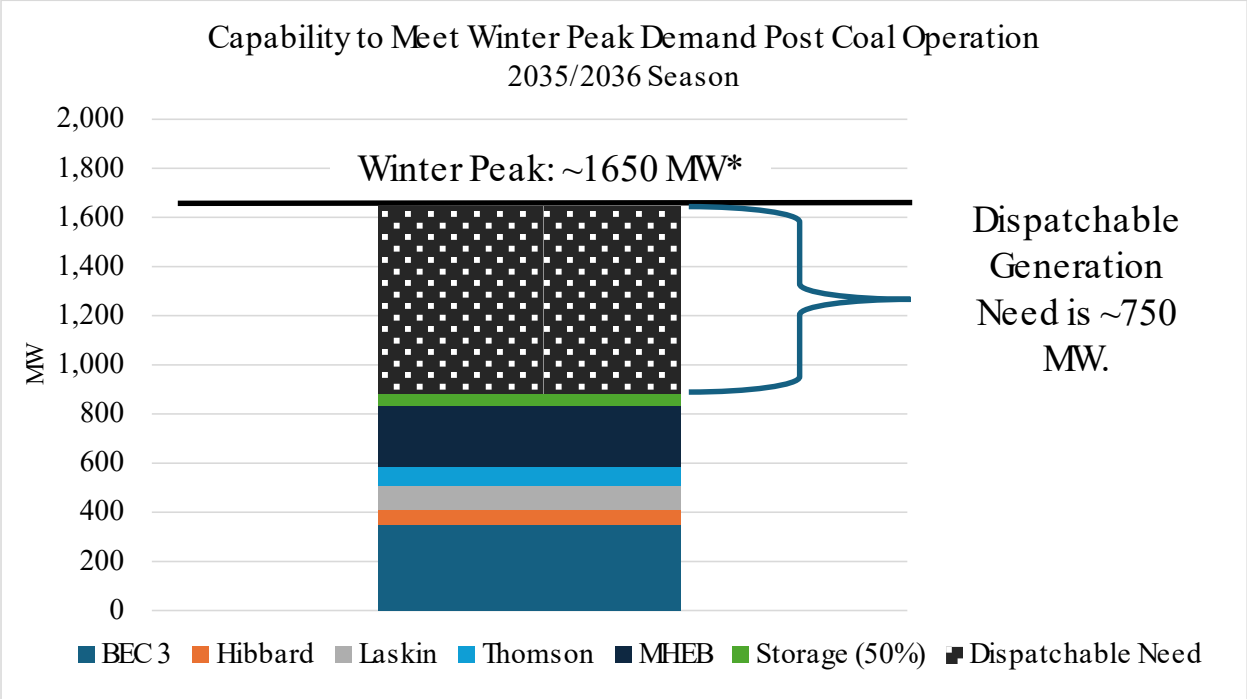
Winter Peak Demand Readiness

Minnesota Power's capability and responsibility to provide reliable energy to meet winter peak demand conditions is an essential and life sustaining service the company provides. During these peak demand periods, which can last for several continuous days, temperatures observed in Minnesota Power's service territory have reached -30 to -50 degrees Fahrenheit. If Minnesota Power is unable to provide energy for essential services to customers and the system experiences blackouts, the impact on life and cost to businesses would be devastating for the region. For these reasons, Minnesota Power must have dispatchable generation that is available with a high level of certainty to meet customer needs during this critical period. As outlined in Minnesota Power's latest customer forecast, AFR 2025[3], winter peak in the mid-2030's is forecasted to be approximately 1650 MW[4]. After ceasing coal operations at BEC unit 4, Minnesota Power needs approximately 750 MW of additional dispatchable generation to meet customer demand during winter peak conditions – see Figure 2 below. Minnesota Power's need increases to 1100 MW if BEC unit 3 is not refueled with natural gas after ceasing coal operations in 2030. Minnesota Power assumes there is no contribution from the Company's wind and solar portfolio because of the intermittency of renewable generation and the critical importance of having high certainty that energy will be available when needed for winter peak conditions. This is a conservative estimate of peaking need because it doesn't factor in forced outages or planning reserve margins that are added to a peak demand. Minnesota Power believes the winter peak is an important reliability criterion, demonstrating that the company is planning for the capability to meet these peak conditions.

[3] Docket No. E-999/PR-25-11

[4] The ~1650 MW system peak is net of customer owned generation, residential distributed generation, and residential/commercial demand response programs.

Figure 2: Minnesota Power's Dispatchable Need to Meet Winter Peak Demand



The "Minimize Gas", "No CC Gas", and "Reduced Gas Capacity Factor" pathways meet this planning criteria with the additional dispatchable gas generation and battery storage in each pathway. For the winter peak demand criteria, the Company assumes 50 percent of the battery capability is available to meet winter peak demand conditions. Depending on the state of charge at the start of peak demand conditions and the duration of the event, a battery might have limited capability to dispatch energy to meet customer demand – a portfolio that relies heavily on batteries to meet winter peak will increase risk of blackouts experienced by customers. The CC technology uses natural gas more efficiently than CT that uses approximately 40 percent more natural gas than a CC to produce the same amount of energy. If during a peak winter event there is limited gas availability, the CC will produce more energy and more efficiently utilize the limited fuel resource. The "Wind/Solar/Storage" pathway, based on the EnCompass capacity expansion results, does not have sufficient storage to meet the winter peak demand criteria. Additional clean firm dispatchable resources are needed in the "Wind/Solar/Storage" pathway to improve reliability.

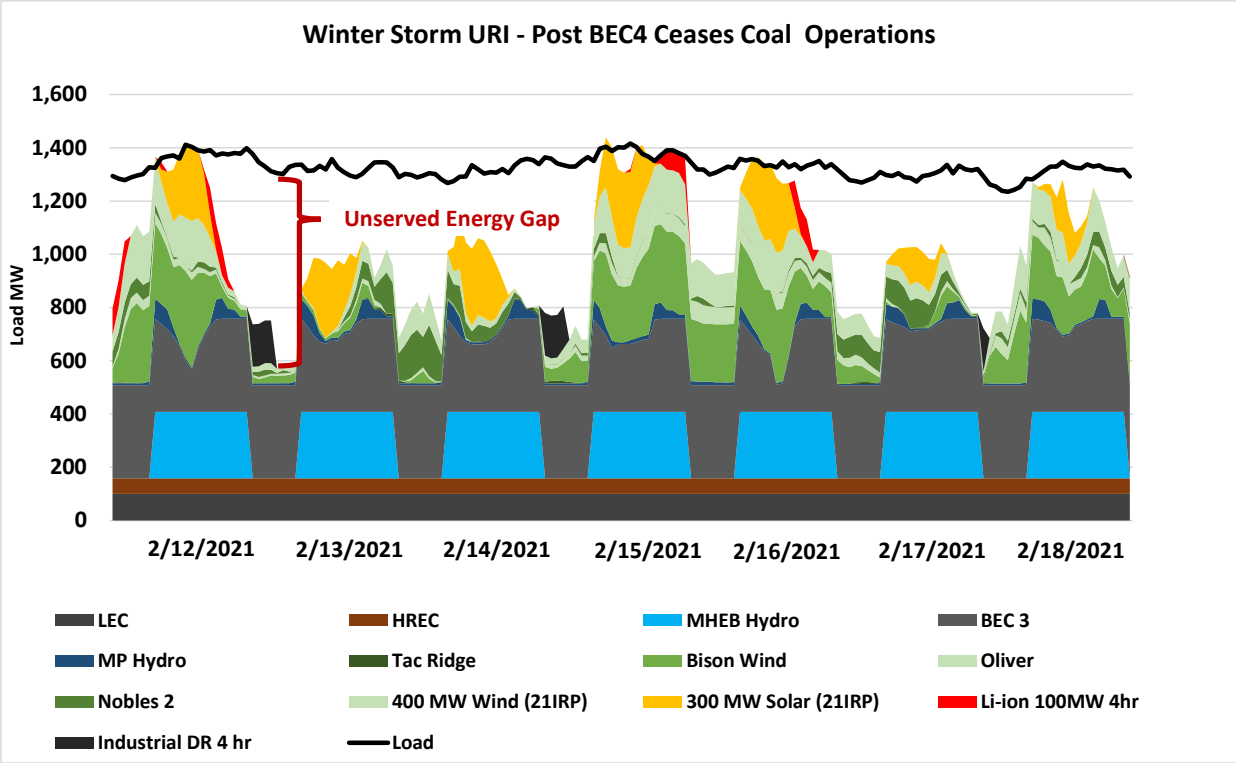
Table 1: Nameplate MW of Additional Dispatchable Generation Available to Meet Winter Peak

	1: Wind/Solar/ Storage Only	2: No CC Gas	3: Reduced Gas Capacity Factor	4: Minimize Gas
CC				650
CT		1300	1300	
Batteries (50%)	650	100	150	100
Small Biomass			100	
Total	**650**	**1400**	**1550**	**750**
Incremental Requirement for Winter Peak: ~750 MW				

Extreme Event Analysis – Winter Storm Uri

In the initial 2025 IRP filing, Minnesota Power evaluated how the recommended Base Plan performed during the Winter Storm Uri event that occurred from February 13 – 17, 2021. This was a multi-day event of high demand due to extreme cold combined with stretches of low renewable production and higher forced outages of traditional resources. Including the Extreme Event Analysis informs Minnesota Power how well an energy portfolio will perform while minimizing unserved energy risk during a critical energy need period for customers. It highlights the critical importance of having a base generation fleet that can dispatch for a continuous number of hours with minimal reliance on intermittent renewables and difficult weather patterns. Figure 3 below shows the power supply performance after BEC unit 4 ceases coal operations in 2035. After BEC unit 4 ceases coal operations, during a Winter Storm Uri type event there are 139 hours of unserved energy and the max unserved energy for an hour is approximately 750 MW. If BEC unit 3 is not refueled with natural gas after ceasing coal, the max unserved energy increases to approximately 1100 MW.

Figure 3: Energy Supply Performance During Winter Storm Uri with Base Case and BEC unit 4 Ceasing Coal Operations



Minnesota Power requires a diverse mix of additional resources to replace BEC unit 4 baseload coal operations to reduce unserved energy risk during an extreme event. The pathways with CC and CTs, along with additional wind, solar, and batteries, reduce the risk of unserved energy during a winter storm Uri like event. Table 2 shows the highest reliability risk is in the "Wind/Solar/Storage Only" pathway, there were 78 hours (46% of hours during the event) of unserved energy during the Winter Storm Uri event for this pathway, in comparison the pathways with new gas generation had no unserved energy hours. Additionally, relying heavily on batteries introduces higher blackout risk, especially if battery state of charge or event duration limits their effectiveness.

Table 2: Winter Storm Uri Reliability Analysis

	Base Case with BEC4 Ceasing Coal	1: Wind/Solar/ Storage Only	2: No CC Gas	3: Reduced Gas Capacity Factor	4: Minimize Gas
Unserved Energy Hours	139	78	0	0	0
Max Unserved	759	1050	0	0	0

Energy MW in an Hour

Loss of Load Expectation Study

As discussed in the initial IRP filing, Minnesota Power outsourced the LOLE modeling effort using PowerGEM, LLC (Formerly Astrapé Consulting). The intent of the LOLE study is to gain insights and develop a benchmarking tool for Minnesota Power's unserved energy risk and to meet NERC requirements for resource adequacy of a system (i.e., 1 day in 10 years loss of energy standard) under different resource portfolios. A LOLE evaluation is a well-documented and accepted method in the industry used to quantify loss of load risk of the system. Minnesota Power views the LOLE analysis as being an effort that will be a benchmark used to review and compare in this IRP and for future planning analysis - it gives the Company a perspective on whether reliability is improving or declining as the Company ceases coal operations and moves toward higher levels of renewable generation.

The LOLE analysis, along with the other reliability criteria, is providing important perspective of using an established reliability criteria metric to determine if there is the need for more resources. The methodology is not a narrow evaluation using accredited capacity, a planning reserve margin, and the net capacity position, but goes deeper into the adequacy risk of the pathway's capability for serving load. This analysis is a portal into the realm of making resource plan decisions based on a more in-depth and informed understanding of system reliability, rather than a more simplistic view of a load and capability summary. This additional complexity is required as the energy systems transform to help ensure load serving can be maintained and not degraded.

MISO identified that reserve margins have been declining and will continue to decline. In the 2024 Reliability Imperative Report MISO states, "Over the last 10-plus years, surplus reserve margins in MISO have been exhausted through load growth and unit retirements".[5] MISO stated about future reserve margins, "…the North American Electric Reliability Corporation (NERC) projects the MISO region will experience a 4.7 GW shortfall beginning in 2028 if currently expected generator retirements actually occur.", and they noted "the OMS-MISO survey tells a similar story." Furthermore, the Midwest Reliability Organization ("MRO") has identified "uncertain energy availability" as an "extreme" risk for the region Minnesota Power operates in.[6] According to the MRO, "Early retirement of thermal resources (e.g., coal and nuclear) that provided on-demand, dispatchable electricity generation creates potential energy shortfalls when replaced with variable, weather-dependent resources that may not be available when needed". Minnesota Power has thoughtfully managed the retirement of coal generation and continuously evaluates if additional resources and customer programs are needed to

[5] https://cdn.misoenergy.org/2024%20Reliability%20Imperative%20report%20Feb.%2021%20Final504018.pdf?v=20240221104216

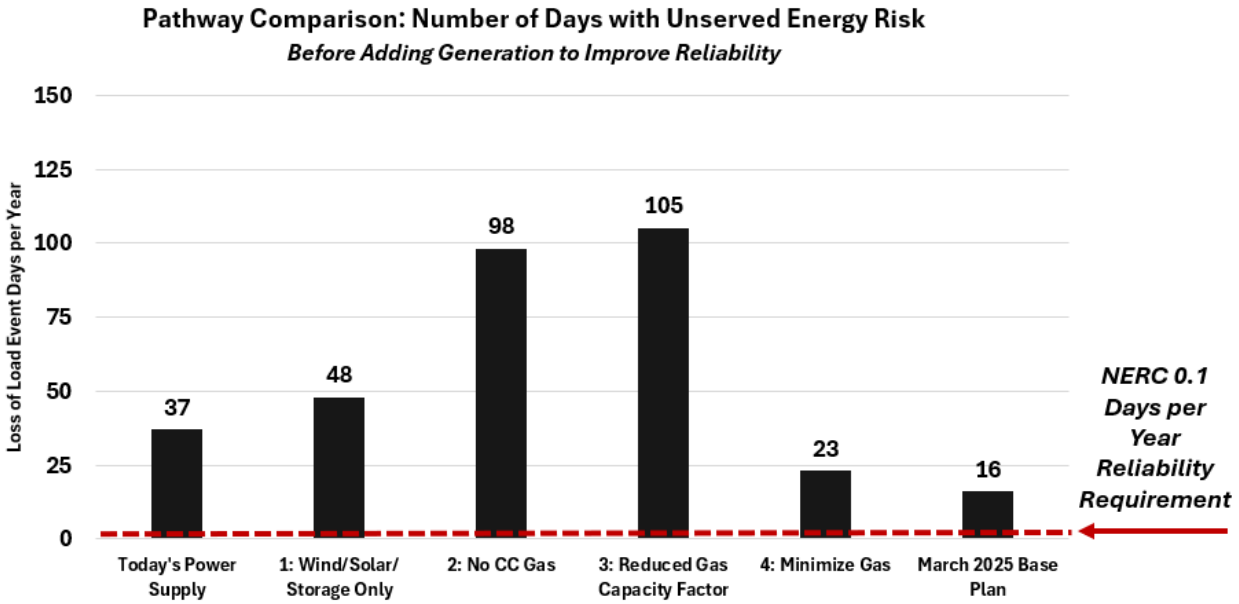
[6] https://www.mro.net/document/mro-2025-regional-risk-assessment/?download

serve customers reliably. The Company reports such evaluations in regulatory filings, including IRPs. Minnesota Power observes that there is increased risk across the regional systems in these trends identified by MISO, NERC and the MRO. Each utility must be prudent in its forward planning to ensure the system does not degrade and create an increased risk of unserved energy and blackouts by increasing the reliance on MISO footprint for core reliability attributes. Minnesota Power's reliability criteria is a pathway that should improve system reliability and not degrade the system.

Minnesota Power looked at the current reliability LOLE metric of its own power supply and further evaluated each pathway for the change that occurs in the Company's reliance on neighboring generation resources to maintain reliability. The LOLE results for Minnesota Power's current system show that, as expected, it does not meet the targeted result of 1 day in 10 years (0.1 for a one-year evaluation) on its own; this is because the system is not planned to operate as an island and is integrated into the broader MISO footprint. As the supply system is transitioned the Company is evaluating with this metric whether the resulting pathway degrades or improves meeting the LOLE results for today's system. Figure 4 below shows the LOLE results when studying Minnesota Power's current system standing alone and based off the EnCompass capacity expansion results for each pathway prior to addressing reliability issues identified with this LOLE study.

This initial LOLE study shows higher risk of unserved energy when CTs are operating within their typical operating permit limitations required to meet environmental regulations. The "No CC Gas" and "Reduced Gas Capacity Factor" pathways identified 650 MW of CT need based on the initial EnCompass capacity expansion analysis. The LOLE results for those pathways were more than double the target of "Today's Power Supply", unacceptably degrading the reliability of the system. These two cases had a LOLE results of around 100 days per year where Minnesota Power would be required to rely on generation from other utilities to maintain load serving metrics. The limited utilization of the resources selected in the initial EnCompass capacity expansion modeling drives the lower reliability metric and results in a resource portfolio with lower than desired reliability. In comparison, the "Minimize Gas" pathway has less than 25 days per year where it relies on the external system. This analysis identified that additional dispatchable generation infrastructure was needed for the "No CC Gas" and "Reduced Gas Capacity Factor" pathways to meet the LOLE reliability criteria.

Figure 4: Loss of Load Expectation Modeling Results - Before Adding Generation to Improve Reliability

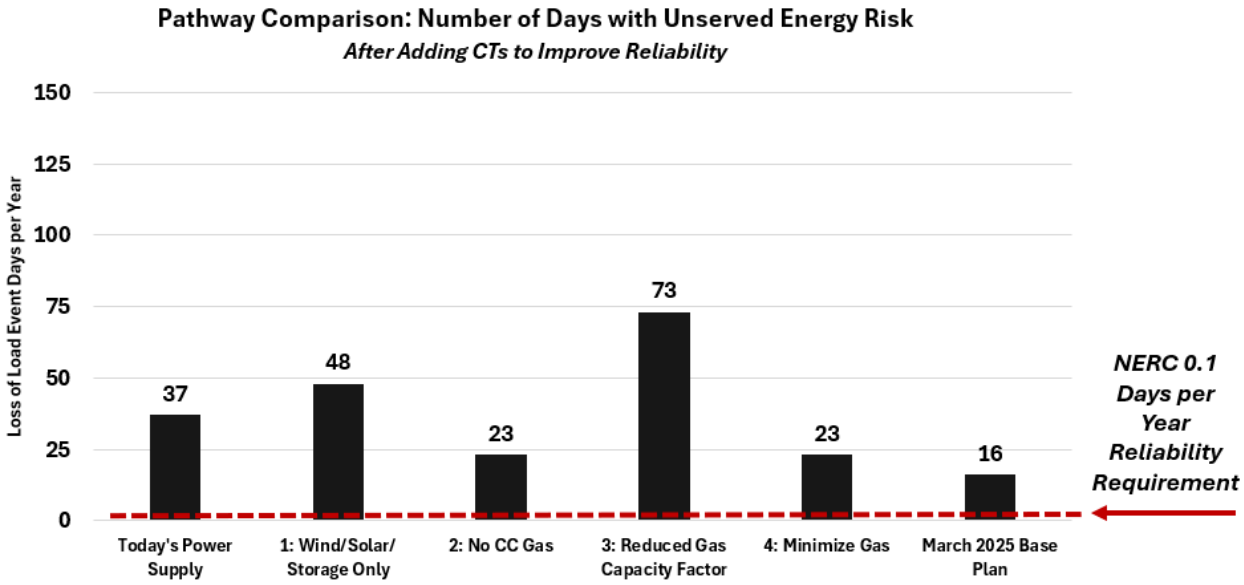


To address the reliability issues identified in the first round of LOLE studies, 650 MW of additional CTs were added to the "No CC Gas" and "Reduced Gas Capacity Factor" pathways, resulting in these pathways having 3-5 CT units totaling 1300 MW. A pathway should improve system reliability and not degrade the system from current levels as the risks identified above related to reliance on MISO footprint and region would exasperate the reliability concerns. Figure 5 shows that with increasing the infrastructure to 1300 MWs of CTs in the "No CC Gas" pathway, the LOLE results improved to 23 days per year, a significant improvement from the approximately 100 days. Representing that the operating limitations and permit requirements are an essential element in planning for systems with the CT technology.

In the "Reduced Capacity Factor" pathway, where additional infrastructure was added the LOLE results improved to 73 days, however still degraded from today's system. Minnesota Power anticipates these results would improve more if the gas generation was operated above the 10 percent capacity factor limitation. Demonstrating that severe limitations in operating parameters can significantly impact the ability to serve load in systems that are transitioning to higher intermittent supply resources.

The "Wind/Solar/Storage Only" pathway also degrades load serving reliability metrics from "Today's Power Supply" due to the challenge of keeping 1300 MW of storage fully charged to serve customer energy needs 7x24. The energy needed to charge the large over reliance on batteries is a degrading force on the load serving capabilities of the system. In comparison, one CC generating unit producing 650 MW of energy in the "Minimize Gas" pathway is the most efficient infrastructure pathway to improve reliability after ceasing coal operations requiring a lower amount of generation facilities overall.

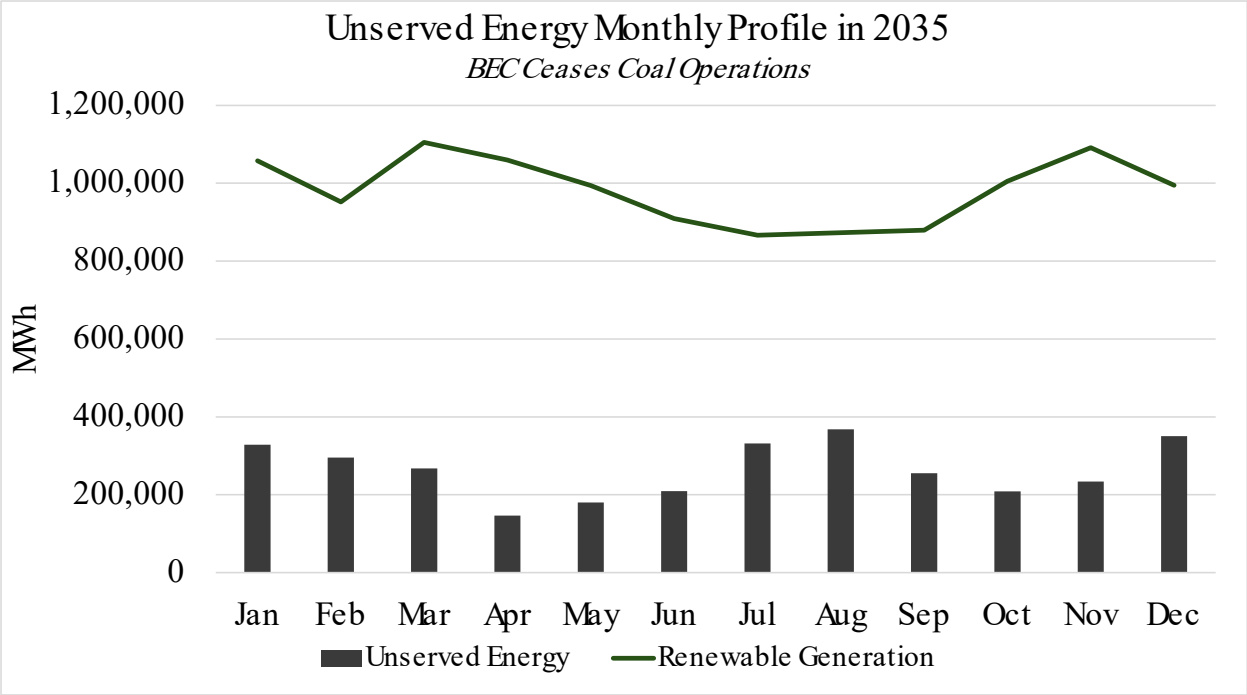
Figure 5: Loss of Load Expectation Modeling Results - After Adding CTs to Improve Reliability



Energy Adequacy

The fourth reliability criteria evaluated in the CFP evaluation was “Energy Adequacy”, where Minnesota Power calculates the unserved energy in the EnCompass modeling for each pathway. The company reviewed which seasons Minnesota Power is observing unserved energy in the EnCompass model to gain an understanding when the system is most at risk as ceasing coal operations. The unserved energy profile is the energy need the EnCompass capacity expansion analysis is adding new resources to meet. The unserved energy need is after factoring in Minnesota Power’s existing dispatchable generation fleet, distributed generation, customer programs, and the current renewable energy portfolio. The annual summary in Figure 6 shows that for a simulated 12-month period in 2035 after BEC ceases coal, there is a distinct relationship between Minnesota Power’s unserved energy and typical renewable generation pattern. The months with highest level of unserved energy coincide with low renewable periods. Demonstrating energy from the renewable portfolio does not match the hourly resource need for serving load. The replacement generation needs to be a diverse combination of dispatchable generation, storage and new customer programs are needed to ensure a reliable power supply for customers. Minnesota Power’s continuous high load factor creates a unique constant need for energy.

Figure 6: Monthly Unserved Energy Profile after BEC Ceases Coal Operations



This is a conservative evaluation given the EnCompass modeling assumes typical renewable generation levels, forced outage rates, and customer demand hourly profiles. The LOLE study discussed above better captures the variability seen in renewable generation and load over several different weather years, where the EnCompass model is a snapshot of one typical weather year look. The EnCompass model has a granular dispatch of MP's system which is insightful on performance across the pathways. Figure 7 shows after BEC ceases coal operations, Minnesota Power has a large unserved energy gap that needs to be met with new generation resources. Note, this look assumes Laskin and Hibbard continue to operate.

The figures show Minnesota Power has a 650 MW block of energy ("blue" area in Figure 7) that requires generation with the capability to operate at a 50 percent capacity factor. Table 3 shows a detailed breakdown of the energy adequacy need, highlighting that after BEC ceases coal operations, if no action is taken, Minnesota Power's system could experience more than 15 consecutive days with unserved energy. In mid-2035, Minnesota Power's unserved energy can't be met by energy storage and renewables alone, without the support of dispatchable generation that can operate for multiple days continuously. This deeper dive in the Company's energy need helps to understand why it is a challenge to meet the reliability requirements of the high load factor system in a "Wind/Solar/Storage Only" pathway.

Figure 7: 2035 Duration Curve of Unserved Energy

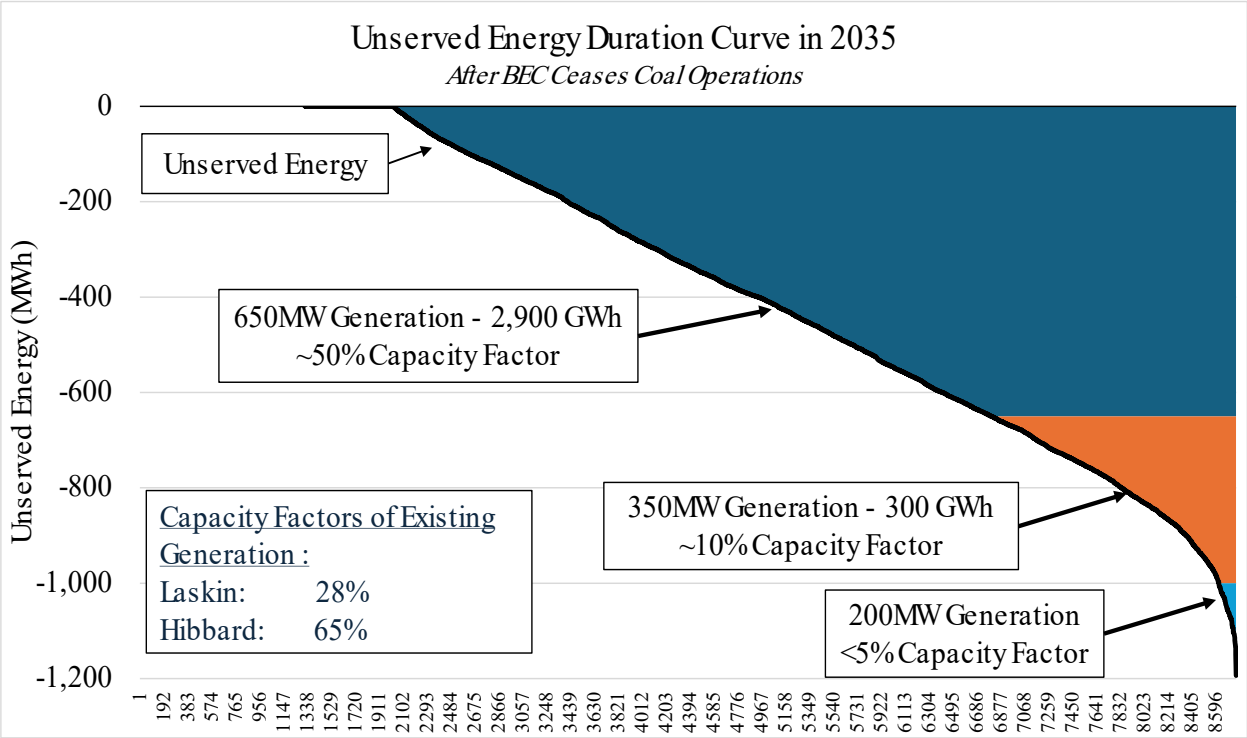


Table 3: 2035 Energy Adequacy Need Metrics After BEC Ceases Coal Operations

	Base Case with BEC Ceasing Coal Operations
Unserved Energy (MWh)	3,174,300
Max Unserved Energy in an Hour (MW)	1,193
Max Duration of Unserved Energy Event (Day)	15
Average Unserved Energy in an Hour (MW)	450
Average Duration of Unserved Energy Event (Hr.)	33
Annual Frequency of Unserved Energy Events	207

Table 4 shows the unserved energy risk for each pathway, prior to increasing to 1300 MW of CTs to improve reliability in the “Minimize Gas” and “No CC Gas” pathways (as identified in the LOLE reliability criteria). Minnesota Power also evaluated the impact to unserved energy risk if wind production is 7 percent below a typical year (Low Wind Production year), which is based on prior observation of actual wind production variances – the results show how a pathway can manage unserved energy risk in lower renewable years. The “Minimize Gas” pathway, with the CC generation, has the lowest level of unserved energy risk. The results for “No CC Gas” and “Reduced Gas Capacity Factor” further supports why additional CT generation infrastructure beyond the 650MW identified

in the EnCompass modeling is needed to be added to the pathways to meet reliability criteria.

Table 4: Energy Adequacy Metrics by Pathway in 2039 – Before Adding Generation to Improve Reliability

MWh	Base Case with BEC Ceasing Coal Operations	1: Wind/ Solar/ Storage Only	2: No CC Gas	3: Reduced Gas Capacity Factor	4: Minimize Gas
Unserved Energy Risk: Base	3,174,300	298,182	190,823	178,922	3,515
Unserved Energy Risk: Low Wind	N/A	511,837	311,066	299,853	5,725
Increase in Unserved Energy with Low Wind		+213,655	+120,243	+120,931	+2,210

Table 5 shows the reduction in unserved energy risk when multiple CT units (1300 MW) are included in the "No CC Gas" and "Reduced Gas Capacity Factor" pathways to improve reliability. The unserved energy risk improved significantly with the addition of more CT units but still have higher levels of unserved energy compared to the "Minimize Gas" pathway. Demonstrating the potential challenge for Minnesota Power to provide reliable and affordable energy service while relying on less flexible CTs to meet the majority of the dispatch needs of Minnesota Power energy intensive customers.

Table 5: Energy Adequacy Metrics by Pathway in 2039 – After Adding CTs to Improve Reliability

MWh	Base Case with BEC Ceasing Coal Operations	1: Wind/ Solar/ Storage Only	2: No CC Gas	3: Reduced Gas Capacity Factor	4: Minimize Gas
Unserved Energy Risk: Base	3,174,300	298,182	20,048	44,890	3,515
Unserved Energy Risk: Low Wind	N/A	511,837	25,818	87,329	5,725
Increase in Unserved Energy with Low Wind		+213,655	+5,770	+42,439	+2,210

The reliability criteria evaluation helped Minnesota Power understand how each of the pathways performed across 4 key criteria that help ensure a reliable power supply, which reduces the risk of observing blackouts and unserved energy as the Company transitions away from coal. The most efficient pathway for customers will minimize the infrastructure required for a reliable power supply. Pathways that had higher levels of dispatchable generation with limits of their capacity factors (i.e. storage and CTs) required significant infrastructure to ensure a reliable power supply for customers.

Factor 2: Environmental Impacts

In the initial 2025 IRP filing, Minnesota Power reaffirmed its commitment to reducing environmental impacts responsibly. Minnesota Power is committed to ceasing coal operations at BEC units 3 and 4, and replacing that energy with the lowest impact on the environment while ensuring a reliable, safe, and affordable energy supply for customers. The "Environmental Impacts" evaluated each pathway's environmental impacts focusing on three core areas:

1. Carbon emissions in the power supply from the energy directly serving customer needs each hour.
2. Compliance risk with EPA proposed carbon regulations and operational permits for new and existing gas generation.
3. Compliance with the Minnesota CFS milestones

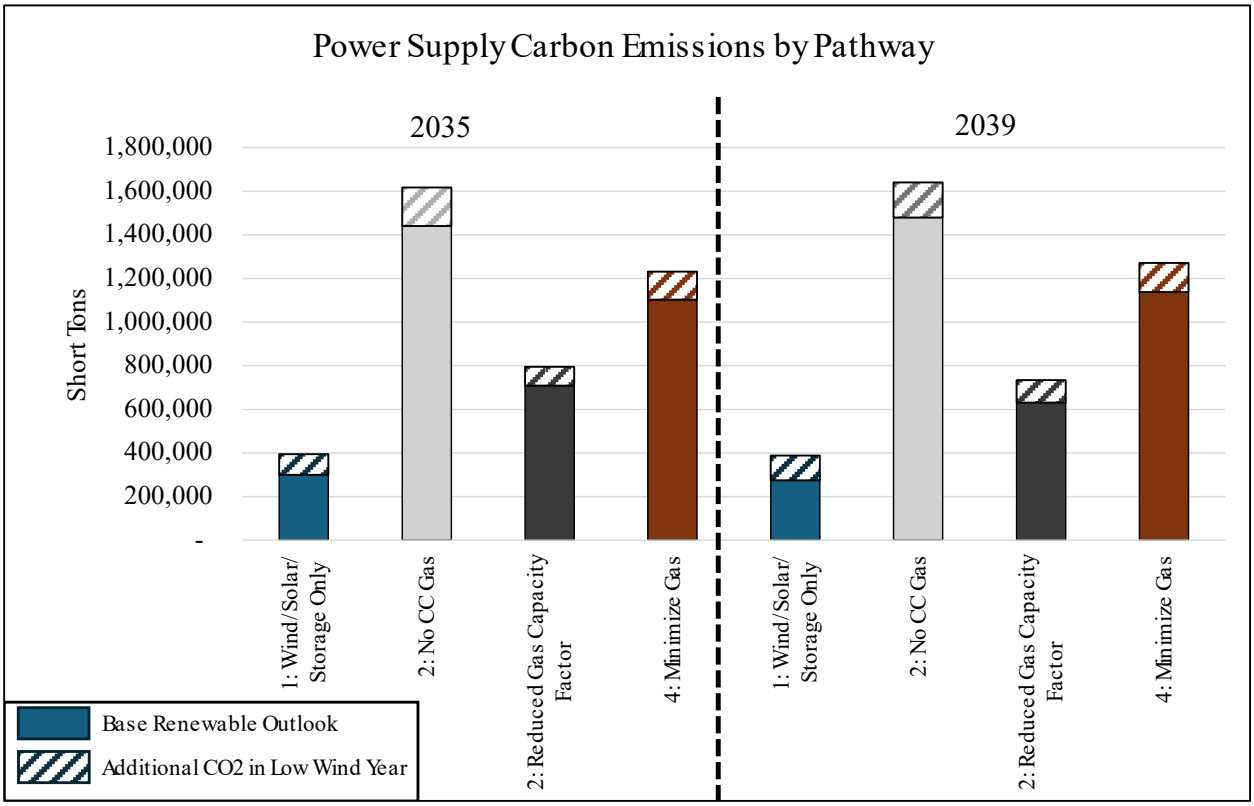
Carbon Emission

The first evaluation calculated the annual carbon emissions attributable to providing a 7x24 reliable power supply to meet customer requirements. Minnesota Power is focusing, in this look, on the carbon emissions from thermal generation and market purchases required for reliability, with no offsets from renewable energy. This approach is intentional so the tradeoffs between pathways with regard to the power supply carbon emissions can be evaluated.[7] In the CFP evaluation, Figure 8 highlights a significant rise in annual carbon emissions between the "Minimize Gas" and "No CC Gas" pathways. This increase reflects the environmental benefits of including combined-cycle (CC) technology, as combustion turbines (CTs) emit roughly 40% more carbon than CC units when producing comparable amounts of energy. Minnesota Power's high energy needs when ceasing coal require large amounts of energy, so these results are indicative to the efficiency of the technologies being utilized and compared in the pathways.

To check the environmental robustness of each pathway, Minnesota Power also evaluated the increase in carbon emissions during a low wind generation year. Which increased in all cases.

[7] This is a different calculation for reporting carbon emissions typically used by Minnesota Power in IRPs and other sustainability reports. Traditionally, when calculating carbon emissions, Minnesota Power factors in the carbon offsets generated from surplus renewable energy within the Company's portfolio to demonstrate compliance with the state regulation requirements.

Figure 8: Projected Annual Carbon Emissions in the Power Supply Associated with Energy Serving Customers



Compliance with EPA Carbon Regulations and Operating Permits

CC and CT have different levels of emissions (i.e. carbon and NOx) due to efficiency and environmental control differences between the technologies. The EPA carbon regulations and operating permits may have different operating limits or caps on energy production or fuel usage. For example, a CT emits approximately 40 percent more carbon than a CC when producing the same amount of energy. The EPA June 17, 2025 Section 111(b) carbon regulation alternate proposal retains new CT limitations that curb energy production to either a 20 percent or 40 percent capacity factor depending on the efficiency of the combustion turbine. In comparison, a highly efficient new CC can meet the emissions limitations required to enable the ability to operate above a 40 percent capacity factor.

Permits to operate a CT or CC can also include additional operating limits for various reasons. In Minnesota Power's review of permits from a sample set of CTs and CCs located in the upper Midwest, the Company found CTs with permit limitations resulting in an estimated 30 percent to 40 percent max capacity factor utilization for the unit. As an example from Minnesota Power's existing power supply, the Laskin Energy Center currently has a heat input limit in the operating permit that results in a ~30 percent capacity factor cap. In 2025, Minnesota Power approached the annual permit limit for Laskin and had to hold back generation in its operations so not to violate the permit. This did not

result in any reliability issues but created a limitation that will need to be considered as the broader regional power supply becomes more constrained due to reductions in dispatchable generation. CCs typically go through additional air permitting because the technology can meet more stringent requirements and therefore don't usually incur caps on operating hours or fuel consumption, which was confirmed by Minnesota Power overview of permits for regional CCs. Minnesota Power's conclusion is that less efficient gas generation, such as new CTs, will likely have operating limits as part of their permits and/or to demonstrate compliance with environmental regulations. Minnesota Power is showing a foundational need for generation that can continuously operate at higher capacity factors after committing to actions and plans for ceasing or exiting from 1500 MW of base load coal generation over the last 10 years. The limitations imposed on CT energy production results in increased risk of unserved energy, unless multiple CT units are added to the power supply - as demonstrated in the reliability criteria evaluation. A CC has the flexibility in operations to meet Minnesota Power's dispatchable energy and reliability requirements, while minimizing the number of gas plants that would need to be built.

CFS Compliance

All pathways meet or exceed the minimum CFS requirements in 2030 and 2035. The EnCompass capacity expansion analysis ensured sufficient carbon free energy was added to the power supply at the lowest cost impact to customers as feasible. Table 6 shows the approximate carbon free energy in each pathway to meet CFS requirements for customers. Note the "Reduced Gas Capacity Factor" and "Wind/Solar/Storage Only" pathways add more renewables than is needed to meet the CFS to offset the lower gas generation.

Table 6 6: Renewable Energy Used to Meet the CFS Requirement in 2035[8]

	1. Wind/Solar/ Storage Only	2. No CC Gas	3. Reduced Gas Capacity Factor	4. Minimize Gas
2035 CFS Compliance	117%	90%	111%	90%

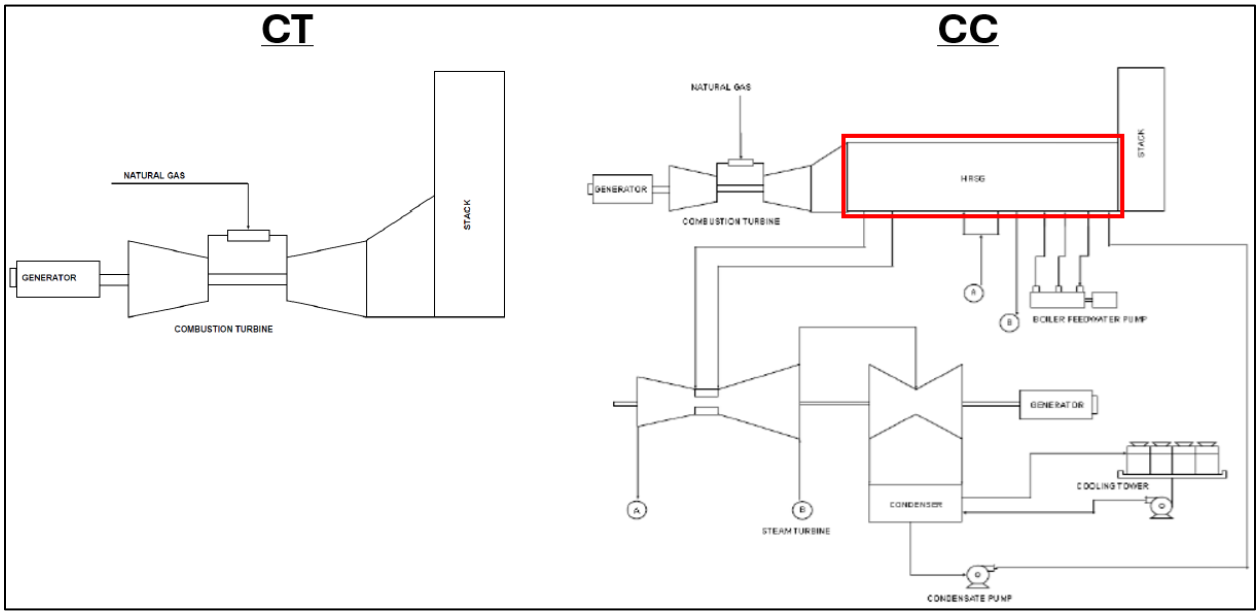
Factor 3: Infrastructure and Fuel Efficiency

Efficiency is a key metric that can be used to evaluate how effective a pathway uses existing electrical and gas and fuel delivery infrastructure. As discussed in the environmental impact section above, CT and CC technologies have fundamental differences in fuel efficiency. Or said differently, a CC generates 40 percent more energy from one MMBtu of natural gas than a CT. The CC technology includes a combustion turbine to produce energy, which is the same combustion turbine used in a CT. The gains in efficiency observed with CC technology is because the exhaust heat from the

[8] The Carbon Free Energy percentage is calculated by dividing total renewable generation production in Minnesota Power's power supply by total energy sales to customers.

combustion turbine is captured in a boiler that produces steam to generate additional energy from a steam turbine, commonly referred to as a Heat Recovery Steam Generator ("HRSG").Figure 9 shows the HRSG (the red box) is placed between the combustion turbine and the emissions stack, capturing the heat before being emitted into the atmosphere. Without a HRSG, the exhaust heat from the combustion turbine is emitted into the atmosphere. Both the CT and CC consume the same level of natural gas, but CC produces more energy because of the additional generation produced from exhaust heat. Please refer to Appendix D: Future Resource Options included in the initial 2025 IRP filing for more details and figures on the operations and technology configuration drawings for a CT and CC.

Figure 9: CT and CC Unit Diagram

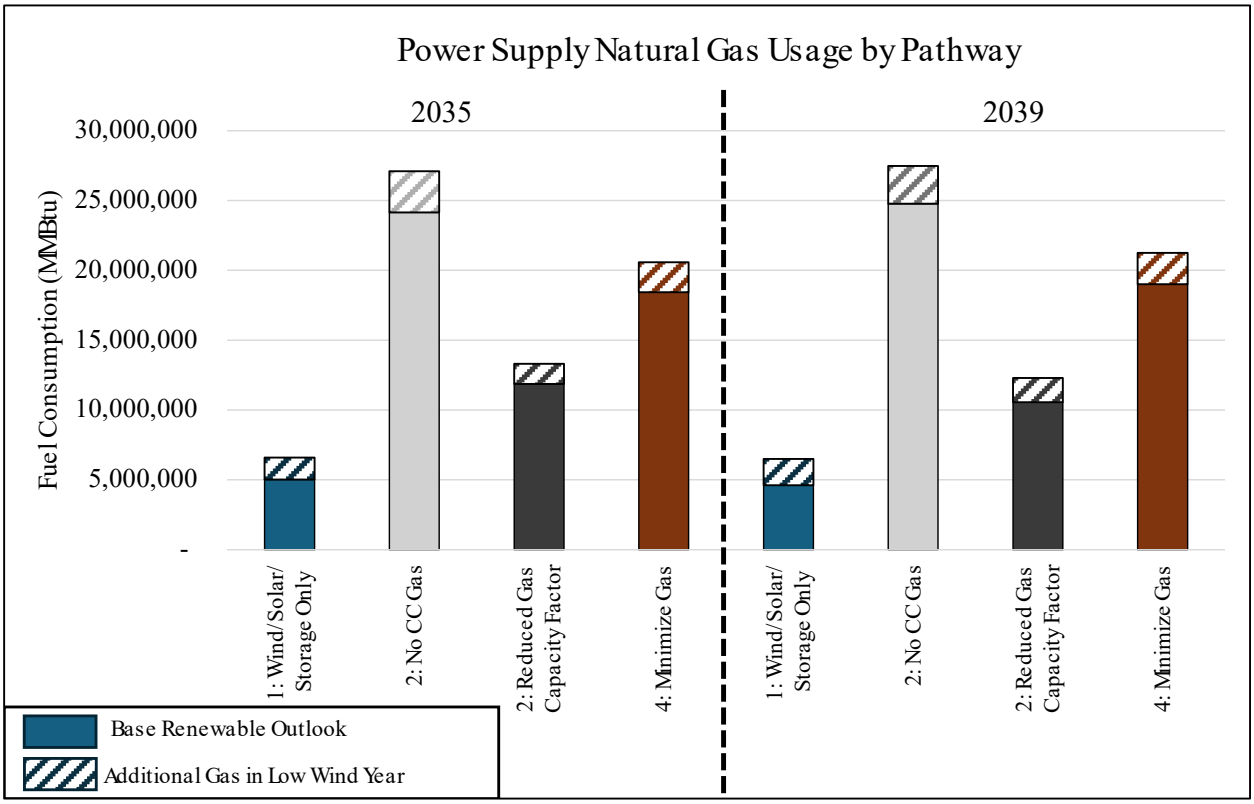


Efficiency is also an important metric to apply when assessing utilization of existing infrastructure. Efficient utilization of existing natural gas delivery infrastructure is important for keeping customer costs lower as Minnesota Power transitions away from coal generation. The CC requires less firm gas supply and utilizes less of the natural gas delivery infrastructure because a CC generates 40 percent more energy than a CT using the same amount of natural gas. Efficiently utilizing existing gas infrastructure reduces the burden and risk on gas delivery infrastructure and lowers risk for additional needed supply to replace coal generation. During a winter peak event, when some regions in North America experienced daily gas price increase to $600/MMBtu during winter storm Uri, a CC would save customers approximately $25 million in one day with its higher efficiency. MP recognizes this is an extreme scenario, but it highlights the importance of having the highest capability for efficiency when the system is constrained. Furthermore, if there was an event where natural gas availability was constrained, a CC will always have the capability to generate more energy with the same molecule of gas than a CT, resulting in higher reliability for customers.

CC technology has the capability to best maximize energy generation potential at an existing interconnect. With CT being limited in total energy production due to permits and EPA carbon regulation, there is a cap placed on the level of generation that can be produced. When re-utilizing an existing interconnect, such as at BEC, maximizing the energy production potential with existing infrastructure will benefit customers and will best prepare Minnesota Power's system for future uncertainty and reduce the requirement for new energy infrastructure.

To measure the efficiency of natural gas usage in each pathway, Minnesota Power tracked the volume of natural gas needed to serve customers reliably. Figure 10 below shows the volume of natural gas generation in each pathway.[9] The figure below shows the "No CC Gas" pathway consumes substantially more natural gas than the "Minimize Gas" pathway. The "Reduced Gas Capacity Factor" and "Wind/Solar/Storage Only" utilized the lowest amount of gas generation.

Figure 10: Annual Natural Gas Usage for Pathways



Factor 4: Customer Cost and Affordability

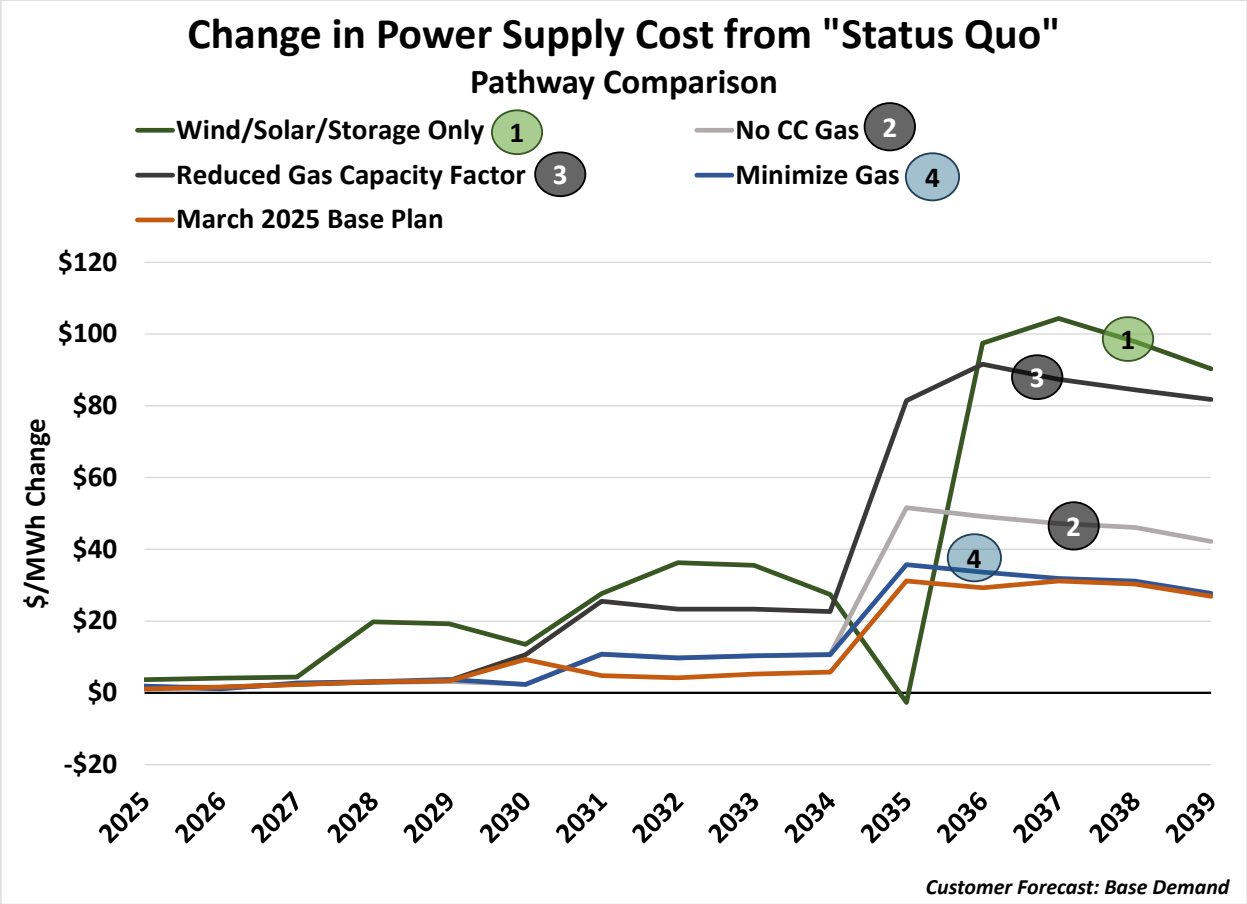
A key concern Minnesota Power heard in the IRP stakeholder process and from a customer survey is affordability of their energy bill. Over 60 percent of Minnesota Power energy sales are to industrial customers that produce products that compete in the

[9] In the "Fuel Efficiency" evaluation the Company assigned natural gas usage to unserved energy in each pathway. The gas usage assumed as average gas heat rate for MISO north based on a third-party forecast.

international market – if energy prices are too high, these industries can't compete in the global markets. The affordability of energy is important to the economic health of all customers in northeast Minnesota, but the economic health of these industrial customers also has an impact on jobs, local schools, and tax revenue in the towns and counties Minnesota Power serves. Furthermore, Minnesota Power's service territory is rural with higher levels of poverty observed in other parts of the state. Affordable energy is important to all Minnesota Power customers as it directly impacts their quality of life. As Minnesota Power transitions away from coal generation, Minnesota Power is forecasting an increase in cost and this is an important and necessary factor to consider in planning. Figure 11 shows the change in power supply cost of each pathway, along with the Base Plan from the March filing from the "status quo". The figures can be useful in informing where customer costs could directionally go if the actions in that pathway are taken but are not meant to be an indication of specific electric rates.

The figures show the "Minimize Gas" pathway best minimizes the cost increase above "status quo" compared to the other pathways and the 2025 IRP Base Plan. The additional capital investment for multiple CT units needed for reliability in the "No CC Gas" and "Reduced Gas Capacity Factor" pathway is a key driver for their higher cost impact and profile. The "Wind/Solar/Storage Only" pathway with greatest wind and battery storage infrastructure additions is the highest cost. Note that the "Wind/Solar/Storage Only" pathway requires additional clean firm dispatchable generation, such as advanced nuclear, to meet the reliability requirements and those additional costs are not captured here.

Figure 11: Pathway Power Supply Cost Comparison – Base Demand Outlook



FACTOR 5: SYSTEM READINESS

Developing plans that are as robust to meet future uncertainty is a core tenant to integrated planning of the system. Minnesota Power's 2025 IRP identifies several pathways that all prepare and advance the system to meet the reliability and policy requirements for customers. Each reaches historic levels of renewables and carbon reduction for this high load factor system. Resource diversity and sufficient capacity additions to achieve greater reliability without degrading the system have been identified as beneficial and key positioning tools for the future. Furthermore, a robust plan provides a near-term and long-term strategy that will perform strongly across multiple plausible scenarios and anticipated variability.

The "Minimize Gas" pathway is a low cost pathway that minimizes infrastructure while providing the most flexibility to navigate uncertainty for Minnesota Power customers – having the hallmarks of a "no regrets" pathway. The "No CC Gas" and "Reduced Gas Capacity Factor" pathways require multiple CT units totaling 1300 MW to provide similar levels of flexibility and reliability observed in the "Minimize Gas" pathway. As demonstrated in the reliability criteria, pathways with gas generation can adapt to low

wind production years. The “Wind/Solar/Storage Only” pathway has limited flexibility to respond to uncertainty, because of the constrained operations of renewables and storage. For example, in this heavy storage reliant system – the assets will need to be in a state of charge more than 50 percent of the year, depending on the storage technology. With “Wind/Solar/Storage Only” pathway relying on significant levels of renewables for charging, this pathway’s performance is more sensitive to weather patterns. Also, storage is limited in the number of hours it can continuously dispatch, further limiting the pathway to adapt to uncertainty and extreme weather events. Storage is best combined in a more diverse portfolio where its attributes can be efficiently utilized.

The efficiency of a pathway to respond to extreme events on the system will better prepare Minnesota Power to operate a reliable system. When the power supply system is stressed, for example during an extremely cold event, utilizing the natural gas infrastructure most efficiently will minimize the risks of customers not having heat during a critical period. With a CT requiring 40% more gas than a CC, overlying on CTs for core energy needs will require more gas pipeline infrastructure to meet max demands and result in higher customer bills. When natural gas prices are extremely high during cold snaps a CC will minimize customer impact because of its efficient use of gas. Energy storage and a diverse renewable portfolio will help reduce the stress on the system, but the reliability criteria demonstrated that gas generation with the most flexible operations is still required to minimize the infrastructure build and associated cost increases. The CT only pathways rely on dispatchable generation that have limited operational flexibility, requiring Minnesota Power to build multiple gas units and larger gas pipeline infrastructure to provide the same readiness as a system with CCs.

Factor 6: Minimizing Stranded Asset Risk and Efficient use of Existing Infrastructure

Minimizing the Risk of Stranded Asset

Minnesota Power is committed to ceasing coal operations at BEC units 3 and 4 on the timeline approved in the 2021 IRP. For Minnesota Power to deliver on our commitment and not have a decline in the quality-of-service customers receive today, the energy production capability and reliability attributes of replacement generation must meet the coal generation timing being retired. One of the most critical reliability attributes of coal generation is a firm fuel supply, along with the ability to dispatch (multiple days or weeks) when needed by the system. In Appendix D and K filed with the initial 2025 IRP is provided a thorough review of existing technologies and emerging technologies, including the technologies capabilities, operational characteristics, and anticipated commercial readiness of each alternative. Natural gas generation is the only technology available to replace all the coal generation operating attributes needed on the timeline on which Minnesota Power has committed to ceasing coal.

The IRP modeling, this pathway analysis, along with reliability criteria, emphasizes the broad planning benefits of adding CC technology to the power supply over CT, because of the efficient use of natural gas, lower carbon emission profile, and greater flexibility in operations for serving a high energy need profile. The CFP analysis identified flexible

generation assets will best serve the variability of a highly intermittent/renewable system for many years. The lowest cost pathway to meet the Minnesota CFS has the lowest new infrastructure build requirements, reducing the risk of stranded assets. The risk of a CC becoming a stranded asset is minimized with its low carbon profile, future enhancements enabled by additional fuel conversions or carbon capture. CC technology is better positioned for future environmental regulations given it's the most efficient way to convert natural gas into energy, with more advanced environmental controls than are included on a CT.

The "Wind/Solar/storage Only" pathway relies on significant investment in still emerging energy storage technologies along with a high volume of infrastructure overall. If the emerging storage technologies don't perform as expected, or lower cost and more efficient storage becomes available shortly after, those assets could also become stranded assets and a significant future infrastructure burden for customers.

The planning will continue as future IRPs will need to identify additional actions to address Minnesota Power's aging existing generation fleet, expiration of large renewable energy power purchase agreements, and the final 10% of the 2040 CFS requirement. The CFP provided evaluated multiple pathways to transition away from coal generation and meet CFS milestones. After the 2025 IRP, the Company is not done with transforming the power system and preparing for continued progress on CFS requirements. The advancement of emerging technology, especially technology that can deliver firm clean power, is a critical pathway to achieving sustainability targets and meeting customer expectations. Minnesota Power is committed to exploring and identifying where emerging technology and modern customer programs can help meet these future needs and continue to deliver an affordable, sustainable, and reliable energy supply for customers in future IRPs.

Re-use of BEC units 3 and 4 Critical Infrastructure to Reduce Carbon Emission

As also shared in the March filing, a key element of Minnesota Power's transition away from coal generation is the maximization of existing energy infrastructure to reduce the cost of the transition for customers and support host communities. This included converting and the work to modernize the Company's High Voltage Direct Current ("HVDC") transmission line to strengthen the grid while delivering low-cost energy from North Dakota, including wind from the Bison wind farm and the proposed Longspur wind project[10]. The company has also used existing infrastructure to reinvest in communities impacted by coal closure by refueling Laskin Energy Center with natural gas, building distributed solar near Laskin Energy Center, and identifying new solar projects at Boswell expected to be online by end of 2027 – these projects provide valuable jobs, along with diversifying the Company's power supply, and meet the objectives of the CFS. BEC is the energy hub of Minnesota Power's service territory with an existing interconnection to high-voltage transmission, access to rail and natural gas pipeline infrastructure. With the final

[10] E015/M-25-309 In the Matter of the Petition of Minnesota Power for Approval of Investments and Expenditures in the Longspur Wind Project for Recovery through Minnesota Power's Renewable Resources Rider under Minn. Stat. § 216B.1645

action to cease coal operations at BEC units 3 and 4, maximizing these existing assets for customers is a priority and can reduce costs of the transition.

The existing MISO generator interconnect at BEC, the equipment and right to send energy on the transmission system to serve Minnesota Power customers, is a valuable asset for customers. Optimizing the use of the interconnect through a MISO surplus interconnection or generator replacement interconnection will reduce the cost of replacement generation as it is viable at the site. The value of the BEC interconnection ranges from $85 to $300 million based on recent network upgrade cost assigned to projects located in northwest MISO. Utilizing the existing interconnect for replacement generation provides more certainty on the implementation timeline of the transition by reducing the MISO generator interconnection queue process, which can currently take more than 3 years to complete.

BEC is located near natural gas infrastructure that is needed to support refuel and replacement natural gas generation at the site, which avoids the need for several miles of new lateral pipeline that could be costly for customers. Minnesota Power's proposed Base IRP Plan already recommends utilizing this infrastructure to refuel BEC unit 3 with natural gas by 2030. The Company continues to investigate and prioritize optimizing BEC infrastructure further for replacement generation after BEC unit 4 ceases coal operations in 2035.

Lastly, reutilizing the combination of natural gas infrastructure and generator interconnection for customers not only reduces the cost of the transition, but also delivers significant decreases in carbon emissions. Replacing BEC unit 4 with an efficient CC will reduce carbon emission by 63 percent at the individual unit, assuming similar levels of operations. With a CC having more flexible operations than coal, plus additional wind and battery storage identified in the pathways and BEC unit 3 refuel with natural gas, Minnesota Power anticipates the carbon reduction at the BEC facility will exceed 75 percent. Along with these benefits, prioritizing the re-use of existing infrastructure provides local jobs, preserves all or a portion of tax revenue base, and contributes to the overall well-being of the community.

BEC unit 4 is jointly owned with WPPI Energy, and any changes will be coordinated with this co-owner, including what happens with the facility after MP ceases coal operations. Minnesota is working closely with WPPI on future plans for BEC unit 4 and the existing infrastructure.

Conclusion of the Pathways Tradeoffs Evaluation

Robust planning is informed by the EnCompass modeling results, along with integrated operational realities, anticipated policy changes, and realistic expectations on what Minnesota Power can achieve over the planning horizon. There isn't a single metric that pinpoints if a single plan is ready for all future uncertainty, it's a combination of several observations across the many factors discussed above. In order for Minnesota Power to complete a successful transition away from coal, the pathway identified needs to have the capability to respond to changes and uncertainty while limiting the risk of adverse effects on Minnesota Power and its customers.

Minnesota Power created a score card (Table 7 below) that ranks each pathway using a “stop light” rating scale across the key factors discussed above. The “stop light” rating scale ranges from “green” to “red” colored. A “green” light signals that the pathway performs better in that category and a “red” light signals lower performance. The basis for choosing the stop light color was informed by the CFP evaluation results discussed above.

Table 7 7: CFP Score Card of Pathways

	1: Wind/ Solar/ Storage Only	2: No CC Gas	3: Reduced Gas Capacity Factor	4: Minimize Gas
Reliability Criteria Performance				
Environmental Impacts				
Fuel and Infrastructure Efficiency				
Customer Cost & Affordability				
System Readiness for Future Uncertainty				
Minimize Stranded Asset Risk & Existing Infrastructure Efficiency				
CFS Compliance				

In conclusion, the CFP evaluation provides useful planning insights into how the four additional pathways meet the requested criteria to minimize natural gas and perform across key resource planning factors. Minnesota Power’s 2025 IRP and this additional analysis have identified several pathways that achieve significant carbon reductions of 90 percent by 2035 and have the actions necessary to reach the historic cease coal commitment in each path. While protecting the core reliability attributes of the system, the analysis highlighted the importance of having a diverse power supply that efficiently maximizes the available technology while minimizing emissions. The distinct requirement to add modern dispatchable generation to replace coal operations is prominent, as Minnesota Power replaces over 1/3 of its energy supply, and is demonstrated as the most robust pathway. Pathway 3 “Reduced Gas Capacity Factor” and Pathway 4 “Wind/Solar/Storage Only” have the lowest carbon emissions in the power supply, although they are challenged on affordability and ensuring reliability. Pathway 4 “Minimize Gas” has the lowest cost profile that meets the reliability criteria as Minnesota Power ceases all coal operations. Pathway 2 “No CC Gas” has similar reliability performance but

requires significantly more CT unit infrastructure to achieve those levels of reliability resulting in a higher cost profile for customers.

Overall, the CFP evaluation highlights the importance of resource efficiency and diversity in managing customer costs and ensuring affordability as Minnesota Power transitions to a cleaner energy profile. The optimal pathway should meet the 2035 CFS requirements with the lowest cost impact to customers, while most efficiently utilizing existing infrastructure, natural gas infrastructure, and best positions Minnesota Power for system readiness and future uncertainty.

C. Capacity Expansion Analysis Results for CFP Evaluation

The following includes the results from the capacity expansion plan analysis, where resources are selected using the EnCompass planning model under the Base Case customer demand forecast, the Minnesota environmental futures, and enforcing compliance with the CFS. The BEC units 3 and 4 operational scenario used in this capacity expansion analysis is the preferred actions identified in the 2025 Base IRP Plan: BEC unit 3 refuels with natural gas by the end of 2029; BEC unit 4 refuels with 40 percent natural gas by end of 2029 and ceases coal operations by the end of 2034.[11] The results from this analysis informed the resource additions included in each pathway evaluated above.

A few updates were made to the EnCompass modeling to incorporate significant federal policy changes since the 2025 IRP was filed, meet order points for the CFP evaluation, and other modeling enhancements. Here is the list of updates made to the EnCompass model:

- PTC and ITC availability were updated per the changes made to qualification requirements in P.L. 119-21
    - PTC and ITC for wind and solar was removed
    - The full ITC for storage is available through 2035
- Added a solar alternative that removes MISO interconnection cost to reflect potential benefits of re-using a surplus or replacement generator interconnect[12]
- Updated hourly wind profile configuration to improve weather correlation between wind farms

Figures 12 through 14 show a summary of the results of the EnCompass Capacity Expansion analysis used to inform the pathways “Minimize Gas”, “No CC Gas”, and “Reduced Gas Capacity Factor”. These figures demonstrate the robustness of the IRP analysis that includes diverse supply and demand side technology alternatives that Minnesota Power considered in the EnCompass capacity expansion analysis. The resource selections shown below are based on an expansion analysis that was done on

[11] In the 2025 Plan, BEC unit 4 is removed from the power supply at the end of 2034 when coal operations cease.

[12] The “surplus/replacement interconnect solar farm” is a representative solar facility located at an existing generation facility, not an actual project identified by Minnesota Power. Actual capability and cost to locate a new solar farm at an existing generation facility is dependent on availability of suitable land that is in close proximity of the existing generation facility.

the following environmental futures: the Reference Case, High Carbon Regulation Cost and High Environmental Costs, Low Carbon Regulation Cost and Low Environmental Costs, and No Carbon Regulation Costs and No Environmental Costs as required for integrated resource planning in Minnesota.

Figure 12: "Minimize Gas" Capacity Expansion Results

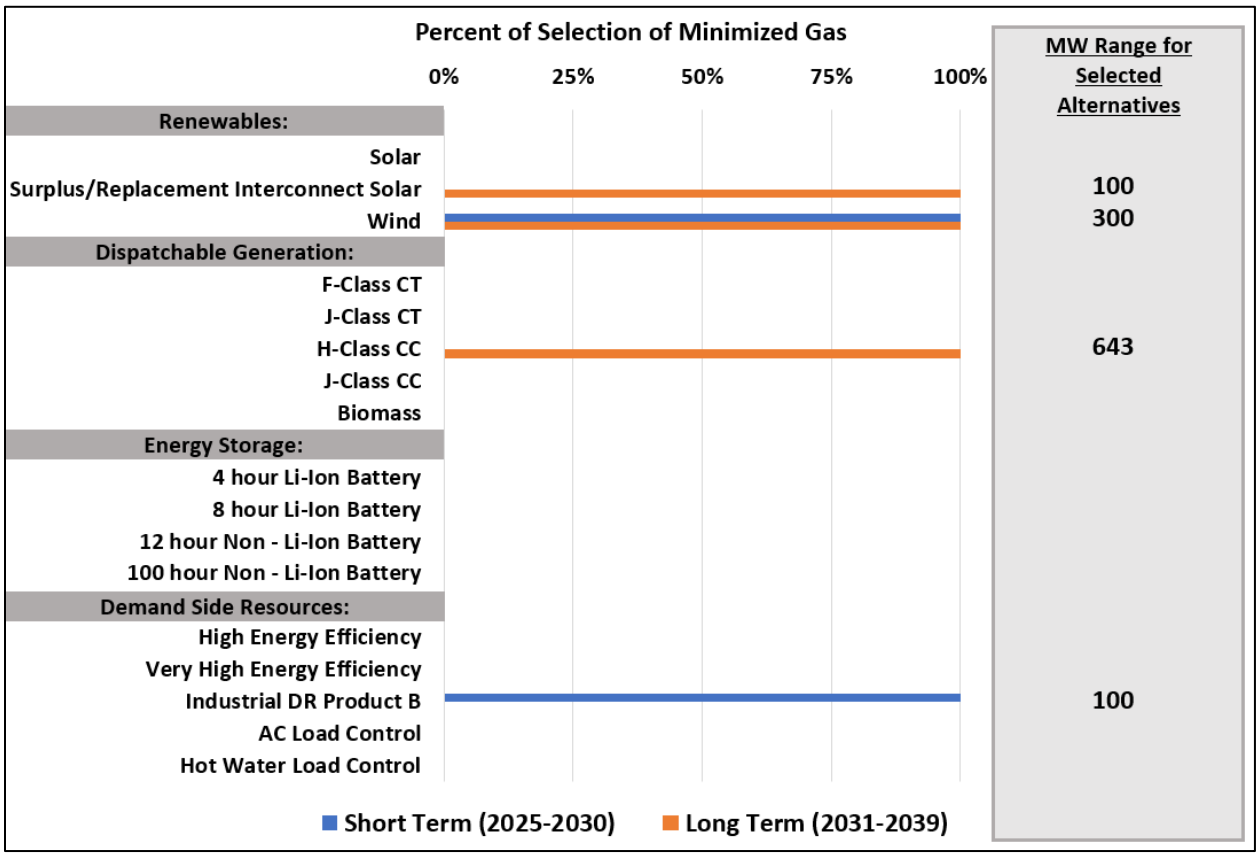


Figure 13: "No CC Gas" Capacity Expansion Results

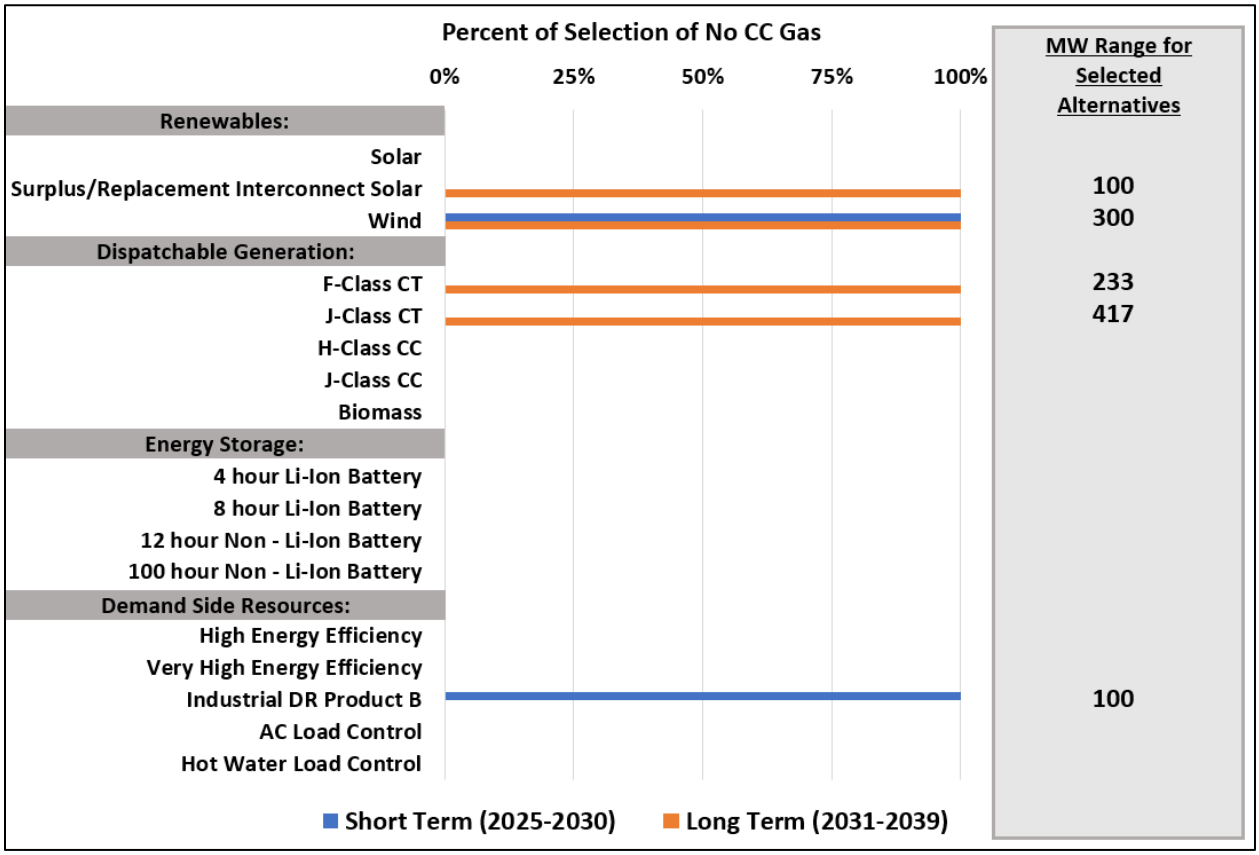
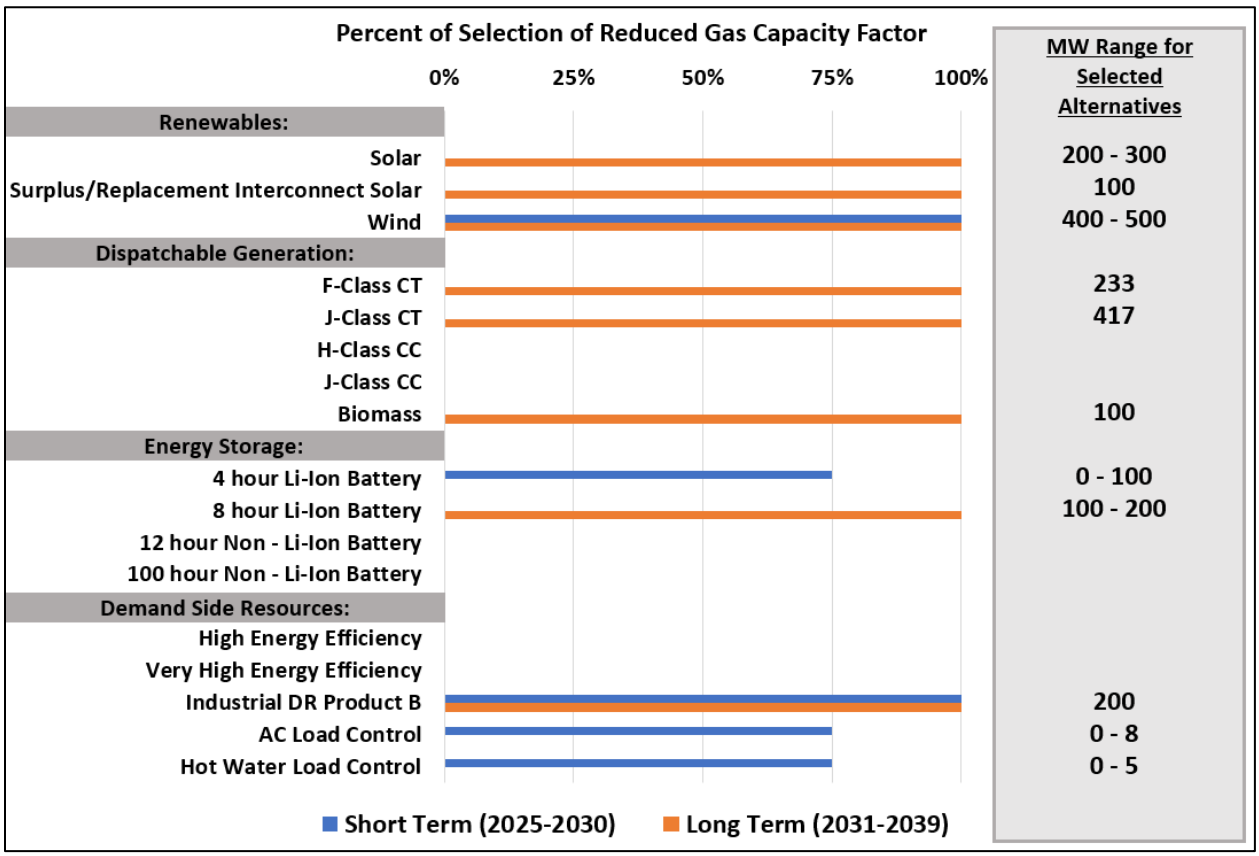


Figure 14: "Reduced Gas Capacity Factor" Capacity Expansion Results



D. Detailed Comparison of Pathway Cost

Minnesota Power performed a cost performance comparison across several pathways. Tables 8 through 13 below show the detailed cost breakdown of each pathway across the different environmental regulation and environmental externality values that were updated in Docket No. E-999/CI-14-643.

Table 8: Cost Comparison of Pathways - Reference Case Carbon Regulation and Environmental Costs

15-Year NPV in the 2025 Plan – Reference Case - Base Load Outlook				
Revenue Requirements ($B)	Power Supply	CO_2 Regulation	Environmental Cost	Total
1. Wind/Solar/ Storage Only	$10.0	$0.4	$6.8	$17.2
2. No CC Gas	$8.9	$0.6	$8.0	$17.6
3. Reduced Gas Capacity Factor	$10.2	$0.5	$7.0	$17.7
4. Minimize Gas	$8.5	$0.6	$7.9	$17.0

Table 9: Cost Comparison of Pathways - High Carbon Regulation and High Environmental Costs

15-Year NPV in the 2025 Plan – High Carbon Regulation Cost and High Environmental Costs - Base Load Outlook				
Revenue Requirements ($B)	Power Supply	CO_2 Regulation	Environmental Cost	Total
1. Wind/Solar/ Storage Only	$10.1	$0.7	$9.4	$20.3
2. No CC Gas	$9.0	$1.1	$11.3	$21.4
3. Reduced Gas Capacity Factor	$10.3	$0.8	$10.0	$21.1
4. Minimize Gas	$8.6	$1.1	$11.2	$20.9

Table 10: Cost Comparison of Pathways – No Carbon Regulation and High Environmental Costs

15-Year NPV in the 2025 Plan – No Carbon Regulation Cost and High Environmental Costs - Base Load Outlook				
Revenue Requirements ($B)	Power Supply	CO_2 Regulation	Environmental Cost	Total
1. Wind/Solar/ Storage Only	$10.0	$0.0	$11.3	$21.3
2. No CC Gas	$8.8	$0.0	$13.3	$22.1
3. Reduced Gas Capacity Factor	$10.2	$0.0	$11.6	$21.8
4. Minimize Gas	$8.5	$0.0	$13.1	$21.6

Table 11: Cost Comparison of Pathways – Low Carbon Regulation and Low Environmental Costs

15-Year NPV in the 2025 Plan – Low Carbon Regulation Cost and Low Environmental Costs - Base Load Outlook				
Revenue Requirements ($B)	Power Supply	CO_2 Regulation	Environmental Cost	Total
1. Wind/Solar/ Storage Only	$10.0	$0.1	$4.0	$14.1
2. No CC Gas	$8.9	$0.1	$4.8	$13.7
3. Reduced Gas Capacity Factor	$10.2	$0.1	$4.2	$14.4
4. Minimize Gas	$8.5	$0.1	$4.7	$13.3

Table 12: Cost Comparison of Pathways – No Carbon Regulation and Low Environmental Costs

15-Year NPV in the 2025 Plan – No Carbon Regulation Cost and Low Environmental Costs - Base Load Outlook				
Revenue Requirements ($B)	Power Supply	CO_2 Regulation	Environmental Cost	Total
1. Wind/Solar/ Storage Only	$10.0	$0.0	$4.1	$14.1
2. No CC Gas	$8.8	$0.0	$4.9	$13.7
3. Reduced Gas Capacity Factor	$10.2	$0.0	$4.3	$14.4
4. Minimize Gas	$8.5	$0.0	$4.8	$13.3

Table 13: Cost Comparison of Pathways – No Carbon Regulation and No Environmental Costs

15-Year NPV in the 2025 Plan – No Carbon Regulation Costs and No Environmental Costs - Base Load Outlook				
Revenue Requirements ($B)	Power Supply	CO_2 Regulation	Environmental Cost	Total
1. Wind/Solar/ Storage Only	$10.0	$0.0	$0.0	$10.0
2. No CC Gas	$8.8	$0.0	$0.0	$8.8
3. Reduced Gas Capacity Factor	$10.2	$0.0	$0.0	$10.2
4. Minimize Gas	$8.5	$0.0	$0.0	$8.5

STATE OF MINNESOTA)
)ss
COUNTY OF ST. LOUIS)

AFFIDAVIT OF SERVICE VIA ELECTRONIC FILING

I, Amy M. Honkala of the City of Duluth, County of St. Louis, State of Minnesota, hereby certify that on the 15th day of January, 2026, I electronically filed a true and correct copy of Minnesota Power's **Supplemental Filing in Docket No. E015/RP-25-127 and E015/PA-24-198** on the Minnesota Public Utilities Commission and the Energy Resources Division of the Minnesota Department of Commerce via electronic filing. The persons on eDocket's Official Service List for this Docket were served as requested.

Amy M. Honkala