414 Nicollet Mall
Minneapolis, MN 55401

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October 31, 2025

—Via Electronic Filing—

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

RE: PETITION – SOLAR AND STORAGE PORTFOLIO
2024 WIND, SOLAR, STORAGE, AND HYBRID REQUEST FOR PROPOSALS
DOCKET NOS. E002/M-24-230

Dear Ms. Bergman:

Northern States Power Company, doing business as Xcel Energy, submits the enclosed Petition to the Minnesota Public Utilities Commission requesting approval of a portfolio consisting of 768 MW of solar generation capacity and 855.5 MW / 3,422 MWh Battery Energy Storage System (BESS) capacity. These projects will reduce carbon emissions, create jobs and economic benefits, and provide necessary capacity and energy to serve our customers. Selected through the Commission's approved Modified Track 2 acquisition process – which the Independent Auditor confirmed was conducted fairly and consistently run – this portfolio represents the first set of new resources proposed to meet system needs identified in the Company's Integrated Resource Plan, approved by the Commission in April 2025. While the broader industry and economy continue to face disruptions and challenges that have affected this solicitation, we are bringing forward a portfolio of projects that will deliver long-term benefits to our customers and communities.

Attached to this cover letter, we provide the required information as specified in Minn. R. 7829, including to whom information requests should be directed.

Portions of this Petition, and Attachment A are marked "NOT PUBLIC" as they contain information the Company considers to be trade secret data as defined by Minn. Stat. §13.37(1)(b). This data includes bid data, details of our project evaluation process, confidential negotiation details, pricing, and other contractual terms. This information has independent economic value from not being generally known to, and not being readily ascertainable by, other parties who could obtain economic value from its disclosure or use.

Attachments B, F, G, H, I, J, K, K-1, L, M, N and O in their entirety, are marked "NOT PUBLIC" as they contain information the Company considers to be trade secret data as defined by Minn. Stat. §13.37(1)(b). This data includes bid data, details of our project evaluation process, confidential negotiation details, pricing, and other contractual terms. This information has independent economic value from not being generally known to, and not being readily ascertainable by, other parties who could obtain economic value from its disclosure or use.

The model Power Purchase Agreements (PPA) are part of the public record through the filed and online Request for Proposal; this public availability creates a risk that developers could potentially infer the terms we negotiated by comparing the redacted versions to the original model PPA. Although they would not be able to determine the exact specifics of the negotiated terms, they could identify the categories and infer the terms where concessions were agreed to in order to secure the project. This insight, when combined with the public information in our Petition, would place the Company at a competitive disadvantage in future and ongoing contract negotiations including its upcoming request for proposals and potentially increase costs for our customers. Public disclosure of this information would also place the vendors of these projects at a competitive disadvantage in negotiating with other buyers on other projects. For these reasons, the agreements have been marked "Not-Public" in their entirety, and the Company maintains this information as trade secret.

Please note that Attachments B, F, G, H, I, J, K, K-1, L, M, N and O are marked as "NOT PUBLIC" in their entirety. Pursuant to Minnesota Rule 7829.0500. subp. 3, the Company provides the following description of the excised material:

Attachment B – Evaluation Process Document:

1. **Nature of the Material**: A description of the bid evaluation process.
2. **Authors**: The Company's Integrated System Planning – Resource Planning & Bidding team.
3. **Importance**: This document discusses the Company's process for evaluating bids into a Modified Track 2 process, including details about bid evaluation criteria. Parties could obtain economic value in future Company resource procurements from the disclosure or use of this document. Knowledge of such information in conjunction with public information in our Petition could also

adversely impact future contract negotiations, potentially increasing costs for these services for our customers.

4. **Date the Information was Prepared**: September 2024 (Updated 10/1/2024)

Attachment F – Bid Data and Details:

1. **Nature of the Material**: Microsoft Excel spreadsheet file containing competitive bid data and pricing for all bids that did not withdraw during the evaluation process of the RFP.
2. **Authors**: The Company's Integrated System Planning – Resource Planning & Bidding team.
3. **Importance**: This document includes confidential pricing and other contract terms and has independent economic value from not being generally known to or ascertainable by other parties who could obtain economic value from its disclosure or use.
4. **Date the Information was Prepared**: August 28, 2025

Attachments G, H, I, J, K, K-1, L, M, N and O are marked "Not-Public" in their entirety. Pursuant to Minn. R. 7829.0500, subp. 3, the Company provides the following description of the excised material:

1. **Nature of the Material:** Attachments G, H, I, J, K, K-1, L, M, N and O are PDF copies of agreements between the Company and Sellers for purchases of power to produce electric service.
2. **Authors:** The agreements were drafted by Company's and Sellers' legal and business development personnel.
3. **Importance:** The agreements include confidential negotiation details, pricing and other contractual terms. The Sellers and the Company maintain this information as trade secret as it has independent economic value from not being generally known to, and not being readily ascertainable by, other parties who could obtain economic value from its disclosure or use.
4. **Date the Information was Prepared:** See the individual agreements for execution dates.

We have electronically filed this document with the Minnesota Public Utilities Commission, and copies have been served on the parties on the attached service list. Please contact Ashley Kehoe at ashley.r.kehoe@xcelenergy.com or contact me at jody.l.londo@xcelenergy.com if you have any questions regarding this filing.

Sincerely,

/s/

JODY L. LONDO
DIRECTOR, REGULATORY & STRATEGIC ANALYSIS

Enclosures
cc: Service Lists

REQUIRED INFORMATION

I. SUMMARY OF FILING

A one-paragraph summary is attached to this filing pursuant to Minn. R. 7829.1300, subp. 1.

II. SERVICE ON OTHER PARTIES

Pursuant to Minn. Stat. § 216.17, subd. 3, we have electronically filed this document with the Commission. Pursuant to Minn. R. 7829.1300, subp. 2, the Company has served a copy of this filing on the Department of Commerce and the Office of the Attorney General. A summary of the filing has been served on all parties on the enclosed service list.

III. GENERAL FILING INFORMATION

Pursuant to Minn. R. 7829.1300, subp. 3, the Company provides the following information.

A. Name, Address, and Telephone Number of Utility

Northern States Power Company doing business as:
Xcel Energy
414 Nicollet Mall
Minneapolis, MN 55401
(612) 330-5500

B. Name, Address, and Telephone Number of Utility Attorney

Xcel Energy
Ian Dobson
Lead Assistant General Counsel
MN1180-08-MCA
414 Nicollet Mall
Minneapolis, MN 55401
(612) 215-4656

C. Date of Filing

The date of this filing is October 31, 2025.

REQUIRED INFORMATION

D. Statute Controlling Schedule for Processing the Filing

Commission Rules define this filing as a "miscellaneous filing" under Minn. R. 7829.0100, subp. 11 since no determination of Xcel Energy's overall revenue requirement is necessary. Minn. R. 7829.1400, subp. 1 and 4 permit comments in response to a miscellaneous filing to be filed within 30 days and reply comments to be filed no later than 10 days thereafter.

E. Utility Employee Responsible for Filing

Xcel Energy
Jody Londo
Director, Regulatory & Strategic Analysis
MN1180-07-MCA
414 Nicollet Mall
Minneapolis, MN 55401
(612) 216-7954

IV. MISCELLANEOUS INFORMATION

Pursuant to Minn. R. 7829.0700, the Company requests that the following persons be placed on the Commission's official service list for this proceeding:

Xcel Energy
Ian Dobson
Lead Assistant General Counsel
MN1180-08-MCA
414 Nicollet Mall
Minneapolis, MN 55401
james.r.denniston@excelenergy.com

Xcel Energy
Christine Marquis
Regulatory Administrator
MN1180-07-MCA
414 Nicollet Mall
Minneapolis, MN 55401
regulatory.records@xcelenergy.com

Any information requests in this proceeding should be submitted to Ms. Marquis at the Regulatory Records email address above.

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STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben	Chair
Hwikwon Ham	Commissioner
Audrey C. Partridge	Commissioner
Joseph K. Sullivan	Commissioner
John A. Tuma	Commissioner

IN THE MATTER OF XCEL ENERGY'S 2024 WIND, SOLAR, STORAGE, AND HYBRID REQUEST FOR PROPOSALS

DOCKET NO. E002/M-24-230

PETITION

INTRODUCTION

Northern States Power Company, doing business as Xcel Energy, submits this petition to the Minnesota Public Utilities Commission seeking approval of resources included in a portfolio consisting of 768 MW of solar generation capacity and 855.5 MW/3,422 MWh Battery Energy Storage System (BESS) capacity.

This Petition follows several prior filings in this docket:

- Our June 21, 2024 Informational Letter, which notified stakeholders of our intent to issue a Request for Proposals (RFP) for wind, solar, and generation resources.
- Our September 25, 2024 filing, which outlined our September 17, 2024 self-build proposal.
- Our January 17, 2025 Letter, which updated the Commission on the bids shortlisted in our RFP.
- Our June 30, 2025 Letter, which provided a status update on the RFP and the shortlisted bids.

The proposed projects are expected to deliver benefits to our customers by providing the capacity and energy we need to serve them safely, reliably, and affordably. The portfolio of projects we present for Commission approval in this Petition will:

- Provide the needed capacity and energy to meet system needs to serve our customers;

- Reduce carbon emissions;
- Capture a time-sensitive opportunity to leverage federal tax credits;
- Enable renewable integration and improve grid reliability by storing excess energy during periods of surplus and releasing it during peak demand, helping to offset the need for additional peak-generation capacity;
- Provide cost-effective energy storage that supports system operations, enhances power quality, and delivers ancillary services to the regional grid;
- Create local, union jobs and generate local economic benefits; and
- Expand renewable energy in Minnesota and the region, helping the Company meet its obligations under Minnesota's expanded Renewable Energy Standard and "100 percent by 2040" Clean Energy Standard.

Specifically, we request that the Commission take the following actions:

- Find that the Company's proposed solar and standalone storage portfolio is in the public interest;
- Approve the Power Purchase Agreements (PPAs) provided with this filing;
- Approve the acquisition and construction of the Company's self-build projects – Blue Lake BESS, Sherco South BESS, Sherco Solar 4 – and the Company's proposed approach of recovery for these project costs for the Minnesota jurisdiction through the Renewable Energy Standard (RES) Rider;
- Approve the Company's acquisition of land rights for the Sherco Solar 4 project;
- Approve the Company's request for a variance of the requirements of Minn. R. 7825.1800, subp. B;
- Authorize the Company to propose any changes to our jurisdictional allocation approach in a future RES Rider filing for resources that we are not able to obtain approval of in another jurisdiction;
- Authorize the Company to recover, through the Fuel Clause Rider, pursuant to Minn. Stat. § 216B.16 subd. 7(3), the Minnesota jurisdictional portion of

the costs incurred under the PPAs from Minnesota retail customers; and

- Establish a procedural schedule such that the Commission may complete deliberations by mid-February 2026. Earlier approval increases the likelihood that projects will qualify for the expiring tax incentives and reduces the risk of construction delays or project failures.

EXECUTIVE SUMMARY

With this filing, we are pleased to present a portfolio of seven solar generation and five Battery Energy Storage System (BESS) projects selected through our 2024 Request for Proposals (RFP). Together, these projects represent 768 MW of solar capacity and 855.5 MW / 3,422 MWh of BESS capacity – an investment that will deliver numerous benefits to our customers while providing the capacity and energy needed to serve them safely, reliably, and affordably.[1]

Despite a challenging landscape, including industry-wide cost pressures, global supply chain disruptions, labor market constraints, and evolving trade policies, the proposed projects represent a strategic commitment to Minnesota's energy future. These projects will deliver clean, renewable energy that reduces carbon emissions and advances state and Company clean energy goals. The BESS projects will further enhance grid flexibility and resilience, support renewable integration, and strengthen system reliability. Further, the projects will create high-quality, union jobs and generate lasting economic benefits for local communities. Taking timely action enables the Company to capture time-sensitive federal tax incentives, minimizing costs for our customers while reinforcing our ability to deliver safe, reliable, and affordable electric service.

Therefore, we respectfully request that the Commission approve the portfolio of projects as detailed in this Petition.

I. DESCRIPTION AND PURPOSE OF FILING

Xcel Energy filed its 2024-2040 Upper Midwest Integrated Resource Plan (2024 IRP) on February 1, 2024. At the time of the filing, the Company was in the process of

[1] Negotiations are ongoing for the two selected build-transfer distributed solar projects in Wisconsin – One Energy Portfolio 1 and 2. Both projects are located in Wisconsin and fall under the jurisdiction of the Wisconsin Public Service Commission. Additional project details can be found in Section IX.

acquiring firm dispatchable resources, as directed in the Commission's Order approving our 2019 IRP.[2]

In October 2024, the Company entered into a comprehensive settlement agreement (Settlement Agreement) with other settling parties to resolve issues related to both the Firm Dispatchable Docket and the 2024 IRP. On April 21, 2025, the Commission issued its Order Approving the Settlement Agreement, with Modifications. In that Order, the Commission approved the Settlement Agreement and the 2024 IRP, including the resource acquisition targets outlined in the five-year action plan.[3] The resources selected and approved through this acquisition are intended to fulfill a portion of the resources identified in the five-year action plan as further described in Section III.F.

Table 1 and 2 below present details of our selected solar and standalone storage projects, including the levelized cost of energy (LCOE) for solar projects and the levelized cost of capacity (LCOC) for standalone storage projects.

[2] In the Matter of Xcel Energy's Competitive Resource Acquisition Process for up to 800 Megawatts of Firm Dispatchable Generation, MPUC Docket No. E002/CN-23-212 (Firm Dispatchable Docket) and In the Matter of the 2020-2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy, Docket No. E-002/RP-19-368, Order (April 15, 2022).

[3] In the Matter of Northern States Power Company d/b/a Xcel Energy's 2024-2040 Integrated Resource Plan and In the Matter of Xcel Energy's Competitive Resource Acquisition Process for up to 800 Megawatts of Firm Dispatchable Generation, MPUC Docket Nos. E002/RP-24-67 and E002/CN-23-212, Order Approving Settlement Agreement with Modifications (IRP Order) at Order Points 2 through 8 (April 21, 2025).

Table 1
Selected Solar Projects[4]

Project Name	Developer	Size (MW)	Inter-connection	Type	Location	LCOE ($/MWh)
						[PROTECTED DATA BEGINS
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]		[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]		[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]		[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]		[redacted]	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]		[redacted]				PROTECTED DATA ENDS]

[4] Negotiations are ongoing for the two selected build-transfer distributed solar projects in Wisconsin – One Energy Portfolio 1 and 2. Both projects are located in Wisconsin and fall under the jurisdiction of the Wisconsin Public Service Commission. Additional details can be found in Section IX.

[5] The project will be connected to the MNEC; however, Xcel Energy executed a new Generator Interconnection Agreement with MISO on October 7, 2024, securing an additional 200 MW of interconnection rights at the Sherco Point of Interconnect.

[6] Formerly known as National Grid Renewables.

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Table 2
Selected Storage Projects

Project Name	Developer	Size (MW)	Inter-connection	Type	Location	LCOC ($/MWh)
						[PROTECTED DATA BEGINS
						PROTECTED DATA ENDS]

Included in the balance of this Petition, we:

- Discuss the state of the industry and market dynamics that affected our RFP solicitation and negotiations,
- Explain how we used the Commission-approved Modified Track 2 acquisition process to solicit and evaluate projects bid in a fair and consistent manner, and describe the contract negotiation process and development of our final portfolio,
- Provide information on lease arrangements,
- Provide an overview of the projects and a summary of key terms in the PPAs, highlighting how those terms are structured to protect our customers and reflect public interest,
- Explain our economic and customer bill impact analysis that demonstrates that the proposed projects are reasonable and in the public interest,
- Discuss our plans for additional near-term resource procurement to provide an

opportunity to secure projects that qualify for expiring federal tax incentives

- Describe our jurisdictional allocation approach,
- Describe the cost recovery mechanisms for the Company's self-build projects, and
- Propose use of fuel and resource recovery clauses related to our PPAs.

We also provide the following attachments in support of our Petition:

Table 3
Attachments

Attachment	Description
Attachment A	Independent Auditor Report
Attachment B	Evaluation Process Document
Attachment C	NSPM RFP Document and Appendices
Attachment D	NSPW RFP Document and Appendices
Attachment E	Bidder Questions and Answers
Attachment F	Bid Data and Details
Attachment G	Fillmore Solar PPA
Attachment H	Grant Solar PPA
Attachment I	Gopher State Solar PPA
Attachment J	Lemon Hill Solar PPA
Attachment K	Crowned Ridge BESS PPA
Attachment K-1	Crowned Ridge BESS Side Agreement
Attachment L	Crane BESS PPA
Attachment M	Mayhew Lake BESS PPA
Attachment N	Sherco Solar 4 Asset Purchase Agreement
Attachment O	EnCompass Modeling Assumptions and Inputs

II. STATE OF THE INDUSTRY

The industry is experiencing sustained and overlapping cost pressures and uncertainty that are affecting the economics of generation resources. Global supply chain disruptions, growing demand, labor market constraints, higher interest rates, evolving trade policies, and new tax regulations are collectively driving up the cost of project development and operations and have continued to fluctuate since bidders submitted their proposals in 2024. These factors in conjunction with global geopolitical uncertainty, have elevated project risk and contributed to adjustments in some project pricing relative to original bids. Project-specific conditions, sensitivities, and mitigation strategies vary, and not all of these dynamics are the primary driver behind every price change. Therefore, before discussing the acquisition process and selected projects, we provide a review of notable dynamics that the Company has managed and balanced to deliver a portfolio of resource additions that captures time-sensitive federal tax incentives, lowering costs for our customers, while ensuring safe, reliable, and affordable electric service.

A. Supply Chain Disruptions and Equipment Availability

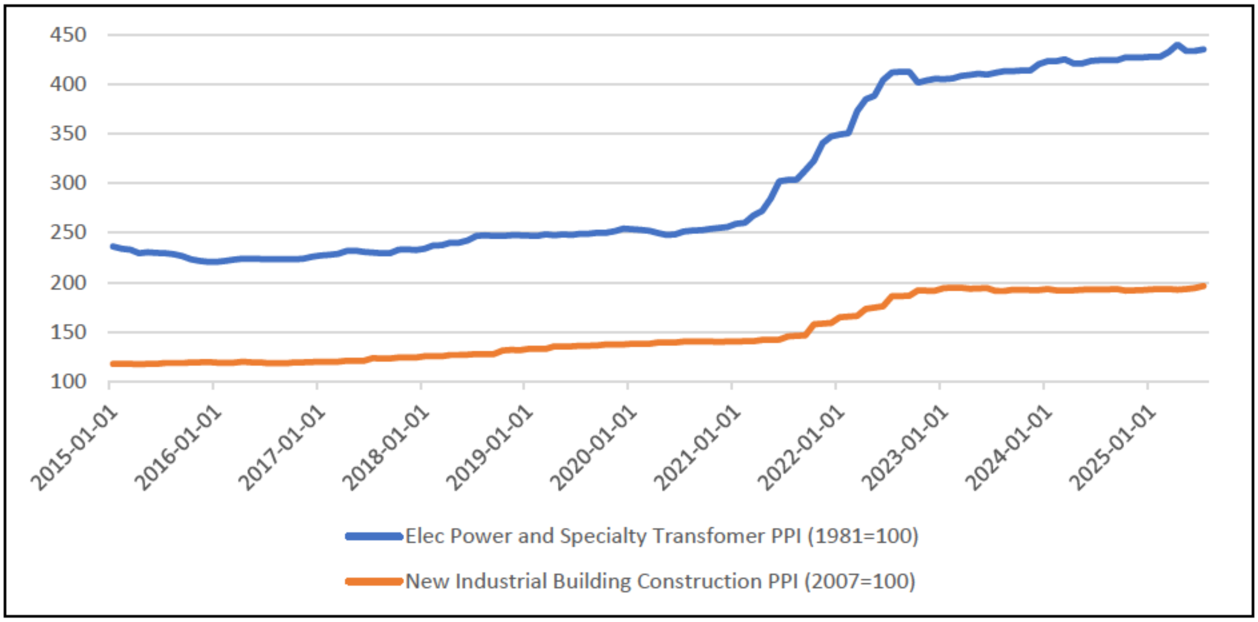
Global supply chain constraints continue to pose persistent and well-documented challenges. Long lead times and elevated prices for key components – such as transformers and inverters – are disrupting project schedules and driving up overall costs. A June 2024 report by the President's National Infrastructure Advisory Council (NIAC) identified a "critical shortage" of power transformers, with lead times more than doubling since 2021 due to pandemic-related production delays and increased demand across the energy sector.[7] Developers have reported similar procurement challenges for high-voltage electrical equipment and solar modules, further straining project delivery times and budgets.

Figure 1 below presents two illustrative Producer Price Indices (PPI) published by the Federal Reserve Bank of St. Louis. These indices demonstrate the scale of recent cost

[7] NIAC, Addressing the Critical Shortage of Power Transformers to Ensure Reliability of the U.S. Grid, pp. 3-4 (June 2024). Available at https://www.cisa.gov/sites/default/files/2024-06/DRAFT_NIAC_Addressing%20the%20Critical%20Shortage%20of%20Power%20Transformers%20to%20Ensure%20Reliability%20of%20the%20U.S.%20Grid_Report_06052024_508c.pdf.

escalations across broader segments of the U.S. economy, following a preceding period of relative price stability.

Figure 1
Illustrative Federal Reserve Producer Price Indices for New Generation Projects[8]



The average PPI for Electric Power and Specialty Transformer Manufacturing from 2021 to year-to-date 2025 was 65 percent higher than the average from 2015 to 2020. For New Industrial Building Construction, it was 44 percent higher. These supply chain challenges continue to exert upward pressure on project costs and delivery times.

[8] U.S Bureau of Labor Statistics, Producer Price Index by Industry: Electric Power and Specialty Transformer Manufacturing [PCU335311335311P] retrieved from FRED, Federal Reserve Bank of St. Louis; and Producer Price Index by Industry: New Industrial Building Construction [PCU236211236211] retrieved from https://fred.stlouisfed.org/series/PCU335311335311P, https://fred.stlouisfed.org/series/PCU236211236211, (Retrieved August 18, 2025).

B. Generation Capacity Lagging Behind Demand Growth

Electricity demand is rising faster than at any point in the past three decades, increasing competition for generation resources and driving up market prices. A 2025 study prepared for the National Electrical Manufacturers Association (NEMA) projects a 50 percent increase by 2050, driven by accelerating electrification and growing data center loads.[9]

In the Midcontinent Independent System Operator (MISO) region, the North American Electric Reliability Corporation (NERC) has classified MISO's risk as "elevated," with a shift to "high risk" projected in the 2028-2031 timeframe.[10] The resources that we are seeking approval for in this petition – together with the Company's broader efforts to capture time-sensitive opportunities to leverage federal tax credits – are needed to ensure we have the capacity needed to reliably serve our customers.

Further, in April 2025, MISO conducted its first Planning Resource Auction for Planning Year 2025-2026 using a Reliability-Based Demand Curve. This new pricing structure prioritizes system reliability and better reflects the increasing value of accredited capacity as the system approaches its minimum resource adequacy targets. The annualized capacity cost across all four seasons cleared at $217/MW-day for the North/Central region. Notably, the auction cleared at $666.50/MW-day for the summer season (June through August) across all of MISO's Resource Adequacy Zones – substantially higher than in previous years.[11] MISO later acknowledged that

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[9] Utility Dive, US electricity demand will grow 50% by 2050, electrical manufacturer group says (April 10, 2025). Available at https://www.utilitydive.com/news/us-electricity-demand-will-grow-50-by-2050-electrical-manufacturer-study/744575/

[10] NERC, 2024 Long-Term Reliability Assessment, pp. 28-29 (December 2024). Available at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_Long%20Term%20Reliability%20Assessment_2024.pdf. Also see: Statement on NERC's 2024 Long-Term Reliability Assessment (June 17, 2025). Available at https://www.nerc.com/news/Pages/Statement-on-NERC%E2%80%99s-2024-Long-Term-Reliability-Assessment.aspx. The 2024 NERC Long-Term Reliability Assessment initially identified MISO as being at high risk of capacity shortfalls beginning in Summer 2025, driven by a mismatch between new generation additions and retiring resources, alongside accelerating load growth. However, NERC later clarified that MISO had submitted mismatched data, which overstated near-term risk.

[11] See "MISO Planning Resource Auction Results for Planning Year 2025-26" at slide 2 (April 2025). Available at https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250428694160.pdf.

a modeling error had inflated auction prices by approximately 20-30 percent.[12] Even with corrected modeling, however, the results highlight the need to bring new capacity online, as demand is expected to increase.

C. Rising Labor Costs and Workforce Constraints

Labor shortages and rising demand for energy infrastructure development are driving up labor costs across the industry. As utilities and developers work to meet growing electricity needs and replace retiring generation, competition for skilled construction labor has intensified. This has resulted in higher contractor pricing, increased schedule risks, and elevated overall project costs.

A recent industry update highlights that solar labor shortages are particularly acute in many states within the MISO region. Labor constraints are also increasingly impacting battery installations. Because a significant portion of battery installation work requires electrical expertise – and nearly all roles demand higher skill levels – the cost impact is especially pronounced. To address these challenges, many firms are investing in training and apprenticeship programs. However, industry leaders caution that scaling up the workforce will take time, even with proactive workforce development efforts.[13] As large-scale projects continue to grow in number and complexity, the availability and cost of skilled labor is becoming a central factor in determining project feasibility, pricing, and execution timelines.

D. Impact of Elevated Interest Rates on Project Financing

Higher interest rates translate into increased borrowing costs and a higher cost of capital. This shift has significant impacts for the energy sector, where adding or replacing generation resources requires substantial, capital-intensive investments that often take years to bring online. As borrowing costs rise, so do the expenses associated with financing and constructing these projects.

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[12] MISO identified a software error in its Loss of Load (LOLE) calculations, where a third-party tool applied an "all hours" methodology instead of the Tariff-defined "daily peak hour" approach. This impacted the Planning Reserve Margin and resulted in inflated auction prices. Simulations using corrected LOLE inputs and adjusted RBDCs revealed that prices in the original PRA were approximately 20-30 percent higher than they would have been absent the modeling error. See "MISO Settlement Adjustments for LOLE Continuing Error" at slide 10 (September 3, 2025). Available at: https://cdn.misoenergy.org/20250903%20SUG%20Item%2002%20Settlement%20Adjustments%20for%20LOLE%20Continuing%20Error%20Presentation716633.pdf.

[13] Reuters, US solar, storage growth clipped by labor shortages (October 17, 2024). Available at https://www.reuters.com/business/energy/us-solar-storage-growth-clipped-by-labor-shortages-2024-10-17/.

On the construction side, elevated interest rates increase the carrying costs for equipment suppliers, which can, in turn, drive up overall project costs. On the financing side, developers typically rely on a mix of project debt, equity, and, in some cases, third-party tax equity or tax credit transfers. All of these financing components have become more expensive, raising the "hurdle rate" – the minimum return required to justify the investment. This is particularly challenging for developers who depend heavily on project-level debt as part of their capital structure. These elevated return thresholds may contribute to increased PPA pricing, depending on project-specific conditions and financing strategies.

E. Evolving Trade Policies Introduce Volatility in Project Development

Project costs have been, and continue to be, affected by shifts in federal trade policy over the past year. In April 2025, the federal government implemented a sweeping set of tariffs, including a 10 percent baseline tariff on all imports and a 25 percent tariff on goods from Canada and Mexico. This action also raised tariffs on certain Chinese goods to as high as 145 percent. These measures directly affect steel, aluminum, solar panels, lithium-ion batteries, and other critical materials used in energy infrastructure.[14]

On August 7, 2025, the federal government activated a new round of reciprocal tariffs targeting nearly every country, marking a significant departure from long-standing trading norms.[15] Regarding China, a temporary tariff truce reached in May 2025 was set to expire on August 12, 2025. However, the federal government announced a 90-day extension, delaying the reversion to higher tariff rates. This extension temporarily maintains the current 30 percent tariff rate on Chinese imports, providing short-term relief to markets that rely heavily on Chinese imports, including energy infrastructure components.[16]

Although some tariffs have since been paused or adjusted, others continue to evolve,

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[14] AP News, Trump Imposes Sweeping Tariffs on All Imports, Shaking Global Markets (April 2, 2025). Available at https://apnews.com/article/trump-tariffs-liberation-day-2a031b3c16120a5672a6ddd01da09933.
[15] MSN News, Map Tracker Reveals Trump's New Tariffs on Every Country (August 7, 2025). Available at https://www.msn.com/en-us/money/markets/map-tracker-reveals-trumps-new-tariffs-on-every-country/ar-AA1K506j
[16] CNBC, Trump Extends China Tariff Deadline by 90 Days (August 11, 2025). Available at https://www.cnbc.com/2025/08/11/trump-china-tariffs-deadline-extended.html.

and many remain in effect. Further, a subset – specifically those imposed under the International Emergency Economic Powers Act (IEEPA) – was ruled unlawful by the U.S. Court of International trade on May 25, 2025. Notably, the ruling applies only to tariffs enacted under IEEPA; product-specific tariffs, such as those on steel and aluminum, remain unaffected.[17] The decision is under appeal, leaving the status of the affected tariffs in legal flux.

The timing of the tariff announcement presented some logistical challenges for project negotiations as well. These policies are not only increasing the cost of developing and maintaining energy assets but also introducing significant uncertainty into procurement and development processes. As trade policy continues to evolve, developers face heightened exposure to price volatility, supply chain risk and changes in regulation.

F. Modifications to Renewable Energy Tax Credit Provisions

The passage of Public Law No. 119-21, also known as the One Big Beautiful Bill Act (OBBBA), on July 4, 2025, introduces a significant restructuring of federal tax incentives for renewable energy development. The legislation imposes a phasedown of key tax credits that have historically supported the viability of wind, solar, and energy storage projects.

Under Public Law No. 119-21, wind and solar projects that do not begin construction by July 4, 2026 must be placed in service by December 31, 2027 to qualify for full tax credits. Wind and solar projects that begin construction by July 4, 2026 remain subject to U.S. Department of Treasury guidance that allows projects to qualify for full tax credits if placed in service by the end of the fourth calendar year following the year construction begins.

On July 7, 2025, the President issued an Executive Order directing the Treasury to issue "new and revised" guidance within 45 days, limiting the use of broad safe harbor provisions unless a substantial portion of the facility has already been constructed. In response, the U.S. Department of Treasury/Internal Revenue Service issued guidance reaffirming the four-year window to place projects in service. However, the guidance

[17] CNBC, Federal Trade Court Strikes Down Trump's Reciprocal Tariffs (May 30, 2025). Available at https://www.cnbc.com/2025/05/29/court-strikes-down-trump-reciprocal-tariffs.html.

eliminated the previously available "Five Percent Safe Harbor" for most wind and solar projects. Instead, developers must satisfy the Physical Work Test, which requires that physical work of a significant nature commence under a binding written contract before a project can qualify as having begun construction.[18]

This change, along with the accelerated timeline for beginning construction on wind and solar projects, significantly narrows the pathway to eligibility and demands more rigorous documentation and project execution. Wind and solar projects that do not begin construction by July 4, 2026 must be placed in service by December 31, 2027 to retain any credit eligibility.

This narrowing eligibility window has already begun to reshape market behavior. According to LevelTen Energy, the average cost of wind and solar PPAs increased by four percent in just the first month since the Bill's passage. Procurement teams are accelerating timelines, with 68 percent reporting an urgent need to "act immediately" to secure resources, and 95 percent maintaining clean energy procurement as a top priority.[19]

Energy storage projects, while not subject to the same immediate cutoff, face a gradual phaseout of incentives beginning in 2034. The credit value will decline incrementally – 75 percent in 2034, 50 percent in 2035, and fully sunset by 2036.[20] This timeline provides a longer runway for storage deployment but introduces long-term uncertainty for developers and investors.

The OBBBA also imposes new restrictions on the use of components sourced from foreign entities of concern (FEOCs), effective for projects beginning construction after December 31, 2025. These provisions are part of a broader effort to reduce reliance on Chinese supply chains and are expected to affect procurement.[21]

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[18] IRS Notice 2025-42, "Beginning Construction Requirements for Purposes of the Termination of Clean Electricity Production Credits and Clean Electricity Investment Credits for Applicable Wind and Solar Facilities" Available at https://www.irs.gov/pub/irs-drop/n-25-42.pdf.

[19] Utility Dive, Renewable Power Purchase Agreement Prices Rising in Wake of One Big Beautiful Bill Act (August 13, 2025). Available at https://www.utilitydive.com/news/wind-solar-power-purchase-ppa-prices-obbb-levelten/757516/.

[20] Basis, One Big Beautiful Bill: Final Impact Analysis on IRA Clean Energy Tax Credits (July 9, 2025). Available at https://www.buildwithbasis.com/insights/one-big-beautiful-bill-final-impact-analysis-on-ira-clean-energy-tax-credits.

[21] Id.

The combined effect of these provisions is a narrowing window of opportunity for developers to secure tax credit eligibility. Projects currently in development must accelerate permitting, interconnection, and procurement activities to meet the statutory deadlines. Compounding this urgency is the fact that nearly one-third of developers are considering suspending or canceling projects due to the OBBBA, which will likely drive PPA prices even higher as supply tightens.[22]

G. MISO Interconnection Challenges: DPP Delays and ERAS Reform

1. DPP Delays

MISO's Definitive Planning Phase (DPP) studies, which assign interconnection costs to projects in the interconnection queue, have experienced increasing lead time and persistent delays. Our RFPs require that bidders incorporate an expected interconnection cost into their bid, but this is becoming increasingly difficult due to both escalating costs and shifting timelines.

For example, this RFP required projects to have submitted a generator interconnection application in the MISO 2021 DPP Cycle, or earlier. At the time the RFP was issued, the Phase II study for the MISO 2021 DPP Cycle was expected to be completed by August 2, 2024. This stage is typically when projects learn of high costs and may choose to exit the queue if those costs are untenable. Further, the MISO DPP 2021 cycle Phase III Study results were scheduled to be complete on September 27, 2024, per the 2021 DPP Cycle timeline released on June 1, 2024. However, the 2021 DPP Cycle schedule has been revised multiple times as described below with Phase II results finally released on July 16, 2025 and Phase III results still pending:

- **July 1, 2024:** Phase II results were delayed to September 20, 2024 – two days after the bid due date of September 18, 2024 – meaning bidders would not have Phase II results before submitting their bid. Phase III was pushed to November 15, 2024.
- **September 1, 2024:** Phase II was further delayed to December 6, 2024, and Phase III to January 31, 2025, reflecting continued challenges in study completion.
- **December 1, 2024:** Phase II was delayed again to April 11, 2025 – after bids

[22] Utility Dive, Renewable Power Purchase Agreement Prices Rising in Wake of One Big Beautiful Bill Act (August 13, 2025). Available at https://www.utilitydive.com/news/wind-solar-power-purchase-ppa-prices-obbb-levelten/757516/.

were shortlisted and the originally expected Traditional Track contract negotiation date of April 1, 2025. Phase III was delayed to June 6, 2025.

- **January 1, 2025:** Phase II was pushed to June 24, 2025, and Phase III was confirmed for August 19, 2025.
- **June 1, 2025:** Both Phase II and Phase III were delayed to July 14, 2025 and September 8, 2025, respectively.
- **July 1, 2025:** Both Phase II and Phase III were delayed by two additional days – to July 16 and September 10, respectively.
- **July 16, 2025:** Phase II study complete.
- **August 1, 2025:** Phase III delayed to September 23, 2025.
- **September 3, 2025:** Phase III delayed to November 7, 2025 with the Generation Interconnection Agreement (GIA) on March 22, 2026.

In sum, the shifting MISO DPP timeline presented material challenges to the RFP process by requiring some bidders to rely on speculative interconnection cost assumptions. This led to project withdrawal from the RFP process. In certain instances, in order to limit such withdrawals, these delays necessitated the inclusion of a conditional pricing mechanism, as described below, to address the interconnection cost uncertainty.

2. ERAS Reform

In response to persistent DPP study delays and rising resource adequacy concerns, MISO launched the Expedited Resource Addition Study (ERAS) as a temporary process to fast-track interconnection studies for generation projects addressing urgent reliability needs. Unlike the standard DPP queue, ERAS offers a streamlined path to a GIA within 3-6 months, contingent on strict eligibility criteria.

The first ERAS cycle began on August 6, 2025 at 8:00 a.m. EST, when MISO opened its online application portal. On that date, the Company submitted an ERAS application to MISO for the following Commission-verified projects:[23]

[23] The Commission, acting as the Relevant Electric Retail Authority (RERRA) to MISO, held a Special Meeting on July 24, 2025 to discuss its role in the MISO ERAS process and reviewed, accepted, and agreed to issue verification forms for the projects proposed by Xcel Energy, Minnesota Power, and Otter Tail Power. The Commission also delegated authority to the Executive Secretary to issue ERAS verification forms for additional projects proposed by the utilities. The Commission's verification confirms the projects' eligibility

- 300 MW Nobles Energy Storage and
- 300 MW Sherco South Energy Storage.

Additionally, third-party developers submitted ERAS applications to MISO in support of the Company's resource needs for the following Commission-verified projects:

- 200 MW Sandhill Energy Storage,
- 100 MW Benton II Solar plus 300 MW Benton Energy Storage, and
- 45-70 MW of incremental capacity that would result from planned upgrades at the Cannon Falls Energy Center.

On September 4, 2025, MISO announced the first 10 projects selected for study in ERAS Cycle 1 (2025, Quarter 3), based on application submission time, common constraint review, application withdrawals, and timely cure of application deficiencies.[24] None of the Company's projects or the third-party projects sponsored by the- Company for Commission verification were selected for study in Cycle 1. Based on the current queue position, at least one of the Company's projects is expected to be selected in Cycle 2 (2025, Quarter 4), beginning on December 1, 2025. This is subject to change, due to MISO's request to FERC to expand the quarterly project study limit from 10 to 15 projects.[25]

If selected in Cycle 2, the project owner must execute a GIA with MISO by mid-February 2026 and make a non-refundable "Milestone M2" payment of $24,000/MW. To keep projects eligible for expiring federal tax incentives and to avoid incurring significant costs before Commission approval, the Company plans to file a petition for approval of a subset of our ERAS projects by the end of November, with a requested Commission decision by mid-February 2026; due to ongoing contract negotiations, the Company was unable to include the ERAS projects in this petition.

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for the ERAS process; it did not constitute final regulatory approval or a finding that the projects are in the public interest. For further discussion of the MISO ERAS process, our proposed projects, and next steps, see our September 12, 2025 Update Letter in Docket No. E002/RP-24-67.

[24] *See* ERAS Cycle 1717096.pdf.
[25] *See* MISO *Revisions to the Open Access Transmission, Energy and Operating Reserve Tariff ERAS Quarterly Study Cycle Expansion Filing,* Docket No. ER25-3543-000720263 (September 26, 2025) at: 2025-09-26 Docket No. ER25-3543-000720263.pdf

The Company expects to request approval of the remaining ERAS projects that will be studied in later study cycles in early 2026.

H. Market Trends and Cost Benchmarking

The dynamics discussed above have increased prices industry-wide and directly affected projects bidding into this RFP, as we will discuss. In the MISO region, Trio[26] reports that maximum observed solar PPA prices exceed $95/MWh in the second quarter of 2025.[27] Figure 2 shows the range of PPA prices during this period. For solar projects located in the Upper Midwest, lower solar irradiance reduces net capacity factors (NCFs) all else equal, which are a major driver of levelized cost. Therefore, it is reasonable to expect many bids here to be within the upper half of the range for MISO, providing a useful benchmark for evaluating solar project costs.

Figure 2
Trio Q2 2025 Market Report – Solar and Wind PPA Prices[28]

The current market reality diverges from the assumptions in the National Renewable Energy Laboratory's (NREL's) Annual Technology Baseline (ATB), which we use for generic resource costs in our EnCompass modeling in our 2024 IRP. To address

[26] Formerly known as Edison Energy.
[27] Trio, "Global Renewables Market Report: First Half of 2025." Available at https://issuu.com/edisonenergy/docs/global_renewables_market_price_briefing_q2_2025?fr=sOTdiNjgzNDg4MTQ.
[28] Id. at p. 6.

market volatility, the Company also modeled a high technology cost sensitivity based on NREL ATB "Advanced" forecast. Additionally, we modeled a sensitivity where the wind, solar and solar + battery hybrid LCOEs prior to 2030 are adjusted to match the 2023 Q1-Q3 actual PPA prices in MISO, reported in the Trio Global Renewable Market Update quarterly reports to align pricing with most recent market trends in MISO.[29] Notably, the Department conducted its own modeling using a *higher* cost sensitivity than the Company's for wind and solar resources.[30] Yet, actual prices received through the Company's competitive RFP process exceeded both sets of assumptions. This shared underestimation underscores that both the Company and the Department acted reasonably and prudently based on the best information available at the time.

As we will discuss in the remainder of this filing, the Company has actively managed these challenges throughout the RFP process and negotiations to minimize risk for our customers and the Company while maximizing the benefits of the selected projects.

III. RESOURCE ACQUISITION PROCESS

On June 28, 2024, the Company issued an RFP seeking 1,600 MW of wind, solar, storage, and hybrid resources with commercial operation dates (COD) through 2029 (Traditional Option). Of the 1,600 MW sought, up to 800 MW of resources could interconnect to the Minnesota Energy Connection (MNEC), contingent on MNEC approval and any pricing updates that may be necessary based on final routing of the line (Contingent Option). The purpose of this RFP was to select resources to fill an identified system need in 2027-2029, and to enable reuse of interconnection rights that will become available as Shero Units 1 and 3 in Becker, Minnesota retire in 2026 and 2030 and Blue Lake Units in Shakopee, Minnesota retire in 2025.

The RFP was open to projects connecting directly to the distribution system in our five-state Upper Midwest system, in addition to transmission-interconnected assets located in MISO Zone 1, including assets that reuse existing points of interconnection with MISO at the Blue Lake Generating Plant and Sherco due to the planned generating unit retirements. As previously indicated, the RFP was also open to bids for projects contingent on interconnecting to the proposed MNEC gen-tie line.

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[29] *See* 2024 IRP, Ch. 5, p. 15-18.
[30] Docket No. E002/RP-24-67, Department of Commerce Comments at p. 30 (August 9, 2024).

Further, we accepted proposals for both newly constructed projects and existing, currently operational projects, if they offered the Company incremental accredited capacity. Finally, we accepted proposals for various project structures: Company

ownership through build-transfers or self-builds, as well as PPAs. Table 4 summarizes the project types that were eligible for this RFP.

Table 4
RFP Eligible Project Types

	Traditional Option	**MNEC Contingent option**
Resource Types	Wind, Solar, Storage, Hybrid	Wind, Solar, Storage, Hybrid
Location	Physically located in MN, SD, or ND, plus:[31] Transmission-Interconnected Proposals: located in MISO Zone 1[32] OR Distribution-Interconnected Proposals: Located in NSPM service territory[33]	Physically located in MN with proximity to proposed MN Energy Connection
Approximate NSP System MW Target	1,600 MW[34]	800 MW
Minimum Size per Project Site	Greenfield: > 5 MW[35] Existing Resources: > 1 MW	> 5 MW

[31] NPSM's affiliate Northern States Power, a Wisconsin corporation (NSPW) issued an RFP to acquire resources in Wisconsin.
[32] https://www.misoenergy.org/. Projects physically located in other zones, including MISO Zone 2 and 3, were not eligible. Projects interconnecting to the MN Energy Connection but choosing the Standard option are already located in MISO Zone 1; no additional information is necessary.
[33] PPA proposals selecting this option must be interconnected to the NSPM distribution system – which includes portions of Minnesota, North Dakota and South Dakota – in a location where the Point of Common Coupling is in the NSPM service territory and the remainder of the location of the DER system allows the interconnection without NSPM being required to provide any compensation or service territory swap with any neighboring utility in order to allow the interconnection. The interconnection must not be on any feeder, or not be on any feeder connected to a substation, that is owned in whole or in part by any utility other than NSPM.
[34] An RFP in Wisconsin sought similar capacity. The amount of capacity taken in Minnesota, North Dakota, and South Dakota was dependent on the relative economics of the bids across both RFPs. Capacity solicited for the King gen-tie was incremental to the NSP System target.
[35] PPA extensions of small, existing projects greater than 1 MW were also accepted.

	Traditional Option	MNEC Contingent option
Project Structure	PPA, Build Transfer (BT), Company self-build	BT, Company self-build
COD	Expected COD by December 31, 2029	Expected COD by December 31, 2029
COD Bonus Points	By June 1, 2027, 20 points By June 1, 2028, 10 points	N/A
PPA Term Lengths	Existing Resources: 5 to 15 years; New Resources: 10 to 30 years	N/A
New or Existing	Newly constructed and <u>some</u> existing projects	Newly constructed only
Co-Location	Bidder must own or have an agreement in place with the owner of any existing co-located generating facility. The existing facility must have its output fully committed to the Company.	
Planned Interconnection Strategy	• Projects proposing new POIs in MISO: must have generator interconnection application in MISO 2021 DPP Cycle or earlier cycle. • Utilization of Surplus or Generator Interconnection Applications at existing MISO POIs, including MN Energy Connection & Blue Lake • Distribution-interconnected projects: must have signed interconnection agreement with NSPM as of June 28, 2024	No MISO interconnection applications are required at time of bid submittal.[36]

The Company's self-build team submitted a self-build proposal on September 17, 2024, and the RFP closed to third-party bids on September 18, 2024. We discuss the Modified Track 2 bidding and acquisition process below.

[36] The Company will ultimately handle interconnection applications for any selected projects that propose to interconnect with the MNEC. A project that already has a generator application in any MISO DPP queue, even queues after DPP-2021, was still eligible to choose this option; the presence of a MISO interconnection application did not preclude a bid from choosing to submit a contingent MNEC bid in this RFP.

The response to the RFP was strong, with 41 bids submitted for 30 distinct projects from 14 bidders, totaling approximately 1,475 MW of solar, 400 MW of wind, 1,350 MW of standalone storage and 1,175 MW of solar plus storage. The bids included three self-build proposals, 21 PPA proposals, and 17 build-transfer proposals. Among the 30 distinct projects, 20 were physically located in Minnesota, three in South Dakota, and six in Wisconsin.[37] Three distinct Contingent option bids were received for interconnection to the MNEC. As further discussed below, with oversight from the IA, at the conclusion of our bid evaluation process, we shortlisted approximately 1,920 MW of solar and storage resources at the conclusion of our bid evaluation process. These resources spanned various contract structures and interconnection locations and included two of our self-build proposals under the Traditional Bid option. We also shortlisted 730 MW of Contingent Bids for further evaluation.

Bidders of projects in the Traditional Option were notified of our shortlist decisions on January 10, 2025; those projects progressed to final contract negotiations. We also notified bidders with projects shortlisted for additional study under the MNEC Contingent Option, asking them to confirm if they would like to proceed with this opportunity and informed them of the next steps:

- Final MNEC route determined by the Commission.
- Bid evaluated for technical feasibility, taking the final MNEC route into consideration.
- Bidders will have an opportunity to reprice their bids based on the final MNEC route.
- Final shortlisting of bids.

As discussed above in Section II.E., federal trade policy continues to evolve. While some tariffs have been paused or adjusted, many remain in effect. These policies are increasing the cost of developing energy assets and introducing greater uncertainty into procurement and contracting processes.

As trade policy continues to evolve, developers face heightened exposure to price volatility and supply chain risk. This uncertainty had a direct and immediate impact on our RFP process; several shortlisted bidders paused or withdrew from contract negotiations, citing the inability to finalize pricing or commit to terms under the new

[37] One bid was submitted for a project located in a state not eligible under the RFP requirements.

tariff regime. As a result, negotiations were significantly disrupted as bid prices became increasingly difficult to hold.

In response to the disruption caused by the evolving trade policy and its impact on pricing stability, the Company implemented a structured mechanism to support continued engagement with bidders. Recognizing that rigid pricing commitments were no longer feasible under the new tariff regime, the Company allowed shortlisted bidders to submit limited pricing adjustments. These adjustments were intended to reflect the real-time cost implications of supply chain volatility, including material cost fluctuations and tariff-related surcharges. The goal was to preserve the integrity of the RFP process while maintaining competition, tension, and transparency. By enabling controlled revisions, the Company aimed to reestablish momentum in negotiations and ensure that final contract terms remained both realistic and executable under the revised market conditions. We discuss contract negotiations and project selection in Section IV.

The projects discussed in this filing are the result of the Modified Track 2 acquisition process approved by the Commission and outlined in its 2019 IRP Order.[38] In the Modified Track 2 process, the Company takes the following steps:

1. Retains an IA to oversee the bidding process.
2. Makes an informational filing detailing the planned competitive bidding process.
3. Issues the RFP.
4. Submits its self-build project bids, if applicable, on the day before the RFP response deadline.
5. Evaluates the bids and selects projects that are in the best interest of customers.
6. Completes contract negotiations for selected projects.
7. Makes a filing to the Commission.

Below, we discuss each step of the competitive bidding process in more detail.

[38] The Modified Track 2 process is also referred to as the "Xcel-Bid Auditor" process. *See* 2019 IRP Order at Order Point 6.A and Appendix A, pp. 4-5.

A. Independent Auditor

In April 2024, the Company entered into a contract with Guidehouse to serve as the IA to monitor and evaluate this RFP process.[39] The IA's Final Report, provided as Attachment A to this filing, concludes that the RFP was conducted on a fair and consistent basis.

The IA provided the following services during the solicitation process:

- Assessed whether RFP materials, including Standard Bidders Forms, provided sufficient and consistent information for Bidders to prepare proposals.
- Identified any potential bias in the criteria to evaluate bids.
- Established that the bid evaluation criteria were applied in a fair and unbiased manner.
- Assessed whether a consistent and transparent methodology was used to screen and rank bids.
- Identified any irregularities in the procurement process.

As part of the Modified Track 2 process, the Company – with oversight from the IA – implemented an internal firewall to safeguard against the self-build team obtaining information that is not available to the public and/or other bidders and improperly influencing the RFP evaluation team. The firewall prevented any communication between the internal teams regarding the RFP, potential self-bid proposal(s), or RFP evaluation. The separation protocol also governed the communication process the RFP evaluation team followed to communicate with all potential bidders, whether internal and external to the Company. The IA monitored our firewall and RFP-related communications between the RFP evaluation team and bidders. Answers to bidder questions (provided as Attachment E) were posted publicly on the RFP website to ensure all bidders had access to the same information at the same time. Public materials related to our RFP are posted on the Xcel Energy website at: https:xcelenergy.com/NSP24RFP.

For this RFP, the firewall that was implemented in May 2024, remained in place on the Traditional Option bids until the shortlist was announced on January 10,

[39] *See* our June 21, 2024 Informational Filing in this docket for discussion of our IA selection process.

2025.[40] The firewall remained in place for the MNEC Contingent Option bids until the bidders were informed of the final shortlist decisions in MNEC Contingent Option on June 24, 2025.[41]

The internal separation protocol worked as designed and helped ensure an objective and transparent bidding process where no bidder had any unfair advantage or disadvantage over another. The IA's Final Report (Attachment A) includes further discussion of the firewall and the cross-firewall working teams and confirms that there were no material firewall breaches and the fidelity of the RFP was maintained throughout the process.

B. Informational Filing

As required by the Commission's 2019 IRP Order, we submitted an informational filing on June 21, 2024. The filing described the selection of the IA; criteria used to evaluate proposals; the planned RFP text; anticipated timeline; details on how the RFP would be announced; details on the types of project structures accepted in the RFP; and information on our contingency plans. This filing also satisfied part C of the Modified Track 2 process, which states: [42]

> *C. Early in the process (preferably with the filing of the company's self-build proposal, discussed below) Xcel files a contingency plan to address the potential for the bidding process to fail.*

C. RFP Issuance

The RFP officially launched on June 28, 2024. We provide the RFP Document and its Appendices as Attachment C to this filing.[43]

In addition to the information provided in our June 21, 2024 informational filing, we provided notice of our RFP to potential bidders through a news release to trade media. The RFP announcements directed interested bidders to the RFP

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[40] Docket No. E002/CN-23-212.
[41] Following the initial shortlist on January 10, 2025, bidders in the MNEC Contingent Option had the opportunity to reprice bids based on the final MNEC route. Additionally, bids were assessed for technical feasibility, considering the final MNEC route, before the final shortlist was determined.
[42] 2019 IRP Order, Appendix A at p. 5.
[43] The NSPW RFP Document and its Appendices are provided as Attachment D.

webpage on the Xcel Energy website, which included all RFP materials and information. Per previous practice, we also provided the news release directly to trade groups to include in communications to their members. Some renewable developers and trade groups are also included in the service list for this filing.

D. Self-Build Submission

As required by the Modified Track 2 process, the Company submitted its self-build bid on September 17, 2024, one day before the third-party bid deadline. This filing satisfied part D of the Modified Track 2 process, which states: [44]

> *D. The day before Xcel receives responses to that request for proposals, Xcel submits its self-build project petition. This petition contains an estimate of final costs for the project and other project details necessary to evaluate the proposal in accordance with the identified selection factors.*

We discuss Blue Lake BESS, Sherco South BESS, and Sherco Solar 4 – the Company's proposed self-build projects, in Section X.

E. Evaluation Process and Shortlist

Part E of the Modified Track 2 process states:[45]

> *E. After receiving bids in response to the request for proposals, Xcel evaluates the bids and select projects for contract negotiation that are in the best interest of its customers. Xcel evaluates the bids using a number of factors, such as –*
>
> 1. *Levelized cost,*
> 2. *Financial capability,*
> 3. *Project schedule,*
> 4. *Project design,*
> 5. *Project risks,*
> 6. *MISO queue position status,*
> 7. *Interconnection and network upgrades,*

[44] Id.
[45] Id.

8. *Energy production profile,*
9. *Site control,*
10. *Project output delivery plan,*
11. *Expected turbine availability,*
12. *Pricing options,*
13. *Project development milestones,*
14. *Exceptions to standard contract terms and conditions, and*
15. *Other relevant factors.*

Using these criteria, Xcel selects projects that are in the best interest of its customers and negotiates contracts with each of the developers.

All bids were electronically received by the revised due date of 5 p.m. CDT on September 18, 2024. On September 19, Xcel Energy's RFP evaluation team opened and catalogued all bids into an internal folder only accessible to the RFP Evaluation and Due Diligence team.

Between September 19, 2024 and January 10, 2025, the bids were evaluated in a three-staged process, which was documented and developed beforehand in the Evaluation Process Document (provided as Attachment B). At a high level, the three stages leading up to the shortlist were:

I. Completeness review.
II. Threshold review.
III. Project scoring and EnCompass modeling.

At the Completeness and Threshold stages, we provided bidders with opportunities to fix any deficiencies that would prevent them from moving forward in the evaluation process. The last phase, where bids were scored, we did not permit any cure opportunities. As a result of the breadth of different project types and technologies in this solicitation with different cost and benefit profiles, a series of analytical steps were then applied after project scoring, including EnCompass modeling.[46] Further, due to the market conditions described earlier, we needed to add a final price screen at the end to ensure that the bids we selected reflected appropriate value to customers. We discuss the evaluation process in

[46] A similar evaluation process was first used in our 2022 Solar and Solar-Plus-Storage RFP. *See* Docket No. E002/M-22-403.

more detail and overall results below. The IA report (Attachment A) and Evaluation Process Document (Attachments B), developed with the IA's oversight, provide further discussion and detail on the evaluation process. Attachment F provides bid data for all bids that did not withdraw.

3. Completeness and Threshold Reviews

During the Completeness review stage, the RFP Evaluation and Due Diligence team reviewed bids to ensure compliance with all bid submittal requirements as outlined in the text of the RFP, including payment of the bid fee and completion of the required bid forms for each bid type. Members of the Due Diligence team included Xcel Energy employees and third-party consultants. All members of the Due Diligence team were subject to the internal firewall.

During the Threshold review stage, subject matter experts, with oversight from the IA, reviewed the various elements of each bid, as detailed in the RFP Document (Attachment C to this filing).[47] Team members were assigned specific due diligence questions **[PROTECTED DATA BEGINS** [redacted] **PROTECTED DATA ENDS]**

The Threshold review is intended to protect customers and the Company from unanticipated capacity shortfalls due to late-stage COD delays and project failures.[48] Throughout the completeness and threshold evaluation, we contacted bidders through a dedicated RFP mailbox, overseen by the IA, and provided them with opportunities – typically five days – to address deficiencies. Nearly all bids needed to address evaluation team questions and/or at least one deficiency during the Threshold Review stage. By maintaining the threshold review standards that we had outlined in the RFP Document, we provided bidders ample time to meet the criteria while ensuring a fair and consistent evaluation for all bids. The results of the Completeness and Threshold reviews and determinations were reviewed by the IA.

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[47] These criteria align with the factors listed above, from Part E of the Modified Track 2 process (Appendix A of the 2019 IRP Order, at p. 5).

[48] In other words, the process aims to identify and eliminate high risk projects early to avoid having projects fail after we have factored them into our future capacity plans.

Table 5 below shows the number of bids passing through the Completeness and Threshold review, culminating in 23 bids reaching the Scoring Stage comprised of 20 distinct projects – 14 solar projects representing 1,628 MW of capacity and six standalone storage projects representing 1,056 MW of capacity. No wind or solar plus storage hybrid projects made it to the scoring stage.

Table 5
Bids through Completeness and Threshold Evaluation Stages

Category	Number of Bids
Withdrawn During Completeness and Threshold Review	4
Did Not Pass Threshold Review	11
Excluded Technical Variation Bids	3
Reached Scoring Stage	23
Total	41

Four bids withdrew prior to Project scoring, 11 bids were eliminated from consideration based on threshold review criteria, and three technical bid variations were excluded as less economically desirable than the remaining bids for the same project. Notably, **[PROTECTED DATA BEGINS PROTECTED DATA ENDS].** This resulted in 23 bids progressing to the Project Scoring and Selection Stage.

The most common reasons for disqualification at the threshold stage were (1) lack of adequate site control; (2) non-conforming location; (3) interconnection issues; and (4) deviations from the technology threshold criteria. We briefly discuss each of these four factors below.

a. Site Control

Site control refers to the extent to which the bidder has secured land rights for the proposed project. Bidders were required to provide documentation on the status of, or information on, site control documents (such as land lease agreements or easements). In our threshold evaluation, we sought to determine whether each developer had begun the process of securing land, any risk associated with obtaining land, and whether the timeline for securing land and permits was accurately reflected in the project timeline such that the project could reasonably be expected to achieve commercial operation by the anticipated COD. **[PROTECTED DATA BEGINS** [redacted] **PROTECTED DATA ENDS]** and pose an unacceptable level of risk. Not only would these projects still have to **[PROTECTED DATA BEGINS** [redacted] **PROTECTED DATA ENDS]** but they would also have to complete construction and achieve commercial operation by the required deadline like all other projects. Therefore, after giving bidders opportunities to address these concerns, we eliminated projects that could not remedy this higher risk of failure due to lack of site control.

b. Non-Conforming Location

Projects bid under the Traditional Option were required to physically be located in Minnesota, South Dakota, or North Dakota, and within MISO Zone 1 for transmission-interconnected proposals, or within the NSPM service territory for distribution-interconnected proposals. Under the MN Energy Connection option, projects had to be physically located in MN with proximity to the proposed MN Energy Connection. **[PROTECTED DATA BEGINS** [redacted] **PROTECTED DATA ENDS]** and was therefore disqualified.

c. Interconnection

Bidders were required to detail plans for interconnection to the transmission or distribution grid. Those seeking transmission interconnection via MISO Zone 1 needed to have submitted an application in the 2021 DPP cycle or earlier. Due to ongoing DPP delays, later-stage or unqueued projects were unlikely to meet COD requirements. Bidders could also use surplus capacity or existing GIAs at MISO points of interconnection (POIs), including MN Energy Connection and Blue Lake.

Distribution-interconnected projects were eligible to compete directly with transmission-interconnected projects. In our 2022 solar RFP – the first to allow distribution-interconnected bids – we implemented a "quiet period" to discourage speculative queue requests.[49] Bidders had to either submit a complete interconnection

[49] Docket No. E002/M-22-403.

request before the RFP notification date or wait until shortlist finalization. To support bid planning, we provided a list of relatively unconstrained feeders.

Evaluating both project types under the same criteria proved effective in the 2022 solar RFP, with many distribution-interconnected submitted and competitively priced. However, none reached contract execution due to challenges shared with transmission-scale projects: inflation, financing risks, permitting, site control, and interconnection. Developers' interconnection cost estimates varied widely, and negotiations revealed unexpected costs not reflected in initial bids.

To reduce interconnection cost uncertainty, this RFP only accepted distribution-connected bids with signed interconnection agreements as of June 28, 2024. Though not optimal, this requirement helped avoid speculative queue entries and cost volatility. Similarly, the Company issued an RFP on January 31, 2025 seeking resources to meet the three percent distributed solar energy standard (DSES) with bids due on April 29, 2025 that also required projects to have a completed system impact study by that date for the same reason. Potential bidders will have another opportunity to participate in a DSES RFP that is planned for June 2026.[50]

For this RFP, we also required distribution-interconnected PPA projects to be interconnected to the Company's distribution system – which includes portions of Minnesota, North Dakota, and South Dakota – in a location where the Point of Common Coupling is in the NSPM service territory, and the remainder of the distributed energy resource (DER) system allows interconnection without the Company being required to provide any compensation or service territory swap with any neighboring utility in order to allow the interconnection. The interconnection must not be on any feeder, or not be on any feeder connected to a substation, that is owned in whole or in part by any utility other than NSPM. If a project did not meet these criteria, it would create regulatory risk to the Company with respect to service territory boundaries and wheeling costs to customers to deliver the energy from others' distribution system to our own.

d. Technology

Bidders were instructed to provide equipment information for each technology type – wind, solar, storage – included in the bid. In addition to providing possible

[50] Docket No. E002,E015,E017/CI-23-403, November 1, 2024 Compliance Filing at pp. 6-7.

manufacturer names and models of a given technology that the bidder may use if shortlisted, the bidder was also required to identify, where prompted on the bidder form, a single make and model for the Company to evaluate. For self-build and build transfer bids, we required that equipment be sourced from our approved vendor list to ensure that the proposed equipment is compatible with our existing systems and infrastructure, meets performance criteria, and complies with regulatory requirements and security standards.

4. *Project Scoring*

The 23 bids that reached the scoring stage consisted of 20 distinct projects: 14 solar projects comprising 1,628 MW of capacity and six standalone storage projects comprising 1,056 MW of capacity. No wind or hybrid solar or wind and storage projects progressed to the scoring stage. The scored bids included nine BTs, 11 PPAs and three self-build projects.

Three criteria were identified for scoring: pricing (55 out of a possible 100 points), capacity and deliverability risk (30 points), and bidder strength and execution (15 points). Further, the Environmental Justice impacts criterion could add or deduct up to 10 points from the bid score (applicable to NSPM bids only). The price evaluation was based on the financial modeling of the projects Levelized Cost of Electricity (LCOE) for solar projects and the Levelized Cost of Capacity (LCOC) for standalone storage projects.

Five criteria were identified that could reduce the overall proposal score: lack of certified diverse suppliers (5 points), exceptions to the BT Purchase and Sales Term Sheet (10 points), transmission congestion at the resource location relative to Company load (15 points), failure to submit a Notice of Intent to Respond (NOIR) for MNEC-interconnected bids (10 points, NSPM bids only), and not responding to Company cure questions in a timely manner (5 points). Bonus points were awarded to early COD projects, with 20 points for projects with a COD before June 1, 2027 or earlier, and 10 for projects with a COD before June 1, 2028. Table 6 provides a summary of all parameters incorporated into the score; the Evaluation Process Document (Attachment B) provides further details.

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Table 6
Bid Score Component Summary

Component	Description	Minimum Score	Maximum Score
Price	Standalone solar bids ranked by the Cost/Median ratio calculated using the LCOE for standalone storage and LCOC for standalone storage All bid types ranked by the Cost/Median Ratio from low to high	0	55
Project capacity and deliverability risk	Risk to providing accredited capacity by the COD indicated in bid; incorporates technical and business practice project risk	0	30
Bidder strength	Bidder qualifications or recent project execution history	0	15
Score Component and Deductor			
Environmental Justice Area Impacts	Benefits provided and/or impacts of the project to Environmental Justice Areas	-10	10
Score Deductors			
MN Energy Connection Traditional and Contingent Bids Only: NOIR Response	Status of a NOIR response	-10	0
Certified Diverse Suppliers	Strength of certified diverse supplier plan	-5	0
Exceptions to model PSA Term Sheet (BT Bids Only)	Magnitude/materiality of proposed exceptions in alternate bid offer, if applicable	-10	0
Congestion	Congestion risk, including rank of current and projected congestion level relative to other bids	-15	0
Failure to Respond to Company Questions in a Timely Manner	Adherence to responding to Company within five business days	-5	0
Bonus Points			
Early COD	Projects with a COD on or before June 1, 2027 through June 1, 2028	0	20

Each project's price is the largest and most complex component of its score. For the price score component of all standalone solar bids and standalone storage bids (regardless of ownership or interconnection option), we evaluated each remaining bid's LCOE and LCOC, respectively, using the pricing and cost information provided by the bidders as well as additional inputs provided by Company subject matter experts where necessary. The Company's bid evaluation team and supporting consultants reviewed key values, supplied by bidders, that heavily impact the LCOE or LCOC as well.

Total scores for each of the bids were calculated and ranked, with solar-only bids and standalone storage bids ranked separately. Each bid score was reviewed and accepted by the IA. After scoring, each bid underwent a Quality Risk Screen to be considered for evaluation in EnCompass. Each bid had to meet a minimum non-price criteria score based on its Capacity Deliverability and Risk score, as well as its Bidder Strength and Execution score. After approval by the IA, all 23 remaining bids passed this screen.

5. EnCompass Modeling

Due to the challenge of comparing the economics of standalone solar bids versus standalone storage bids, EnCompass was used as a second round of scoring in the bid selection process. As discussed in the Evaluation Process Document, a pre-determined, fixed maximum MW of each resource type was identified to advance for analysis in EnCompass. The collective MW quantity of the remaining solar projects at this stage exceeded this threshold. Consequently, after approval by the IA, the two lowest scoring solar bids were excluded, and the remaining 21 bids moved forward for EnCompass modeling.

In this step, the Company established a baseline scenario in EnCompass by running an expansion plan with generic resources filling in the capacity needs. The updated base case is primarily based on the 2024 IRP modeling with several changes consistent with the base case in the Settlement Agreement modeling: (1) include the five-year PPA extension with Manitoba Hydro; (2) update solar production profiles; and (3) update incorrect retirement dates for four existing resources.

We then created a capacity "hole" in the plan by removing 1,600 MW of capacity met by generic resources on and off the MN Energy Connection in 2027 and 2028. We then allowed the model to fill the hole by optimizing additions of the project bids (and restricted the model so that it could not select generic resources) under two scenarios. For the first scenario, we used the IRP load forecast; for the second scenario, we used the 2024v2 load forecast, which was also filed with the rate case in Docket No. E002/GR-24-320. Distinct projects could only be selected once. If a project had been bid in once as a PPA and once as a build-transfer, EnCompass could only choose the lowest cost option.

In other words, we started with the updated 2024 IRP base case modeling, removed generic resources it was selecting between 2027 and 2028, and allowed the model to pick from the remaining project bids to meet the system needs during the acquisition time window between 2027 and 2029. This methodology allows the model to test which bids can meet the identified capacity and energy need under both vintages of the load forecast. As further discussed below, with the approval from the IA, we used the portfolio under the 2024v2 load forecast as the basis for the final shortlist. This allows us to account for load growth and project dropout during the negotiation process amid uncertainties in the market.

6. Final Price Screen and Shortlist Identification

All bids that were selected by EnCompass were further evaluated to ensure a beneficial balance between cost and capacity needs.

Ultimately, the proposals we received in response to this RFP were higher in price than the generic resources modeled in the IRP. To that end, the Company performed another EnCompass modeling run with updated generic resource pricing, among other updates, as discussed in Section XI.

We acknowledge that structural changes have occurred in the market. Therefore, we imposed a price cap that excluded any bids with prices that had **[PROTECTED DATA BEGINS** **PROTECTED DATA ENDS]**. Our economic analysis of the projects later demonstrated the appropriateness of this threshold, as we will discuss in Section XI.

On January 10, 2025, the IA approved the selection of 17 distinct projects from eight different bidders, totaling 1,595 MW of solar capacity and 1,056 MW of standalone storage capacity, for the shortlist. Projects on the Traditional Bid option shortlist include:

- 14 distinct projects – eight solar projects (868 MW of capacity) and six standalone storage projects (1,056 MW of capacity),
- Ten PPAs, two BTs, and two self-builds,
- 12 transmission-interconnected and two distribution-interconnected,
- Ten located in Minnesota, two in South Dakota, and two in Wisconsin.

For the three MNEC Contingent shortlisted bids, two are BT projects and one is a self-build, totaling 727 MW of solar capacity.

Although the RFP initially sought 1,600 MW, we shortlisted a total of 2,650 MW to better align with the projected increase in system capacity and energy needs by 2030, as indicated in the latest load forecast at that time. This expanded shortlist reflects a strategic response to anticipated load growth higher than the IRP load forecast and accounts for the possibility that not all shortlisted projects will proceed to final contracting.

Given the ongoing uncertainty regarding tariffs and the availability of production and investment tax credits under the Inflation Reduction Act – as well as continued delays in MISO interconnection studies – there was a risk that some shortlisted bids might not reach the final contracting stage. Further, the final routing of the MNEC project was pending and could have rendered one or more of the Contingent bids uneconomic, further reinforcing the need for a broader shortlist.

Table 7 shows the shortlist, as presented by the Company to the IA. As shown below, the shortlist included a mix of interconnection methods, geographic distribution, and a relatively broad range of prices. The IA determined that the shortlist was appropriate and aligned with the predefined evaluation criteria.

Table 7
RFP Shortlisted Solar Bids

Project Name	Bidder	Projected In-Service Date (Month/ Year)	Size (MW)	Interconnection	Location	Type	Contingent	Final Score	LCOE Bid Price ($/MWh)[51]
								[PROTECTED DATA BEGINS	
								PROTECTED DATA ENDS]	
[PROTECTED DATA BEGINS									
							PROTECTED DATA ENDS]		

[51] The LCOEs reflected in the table are based on bid data and RFP evaluation protocol and do not reflect adjustments made after bid selection.

Table 8 presents the same data for the shortlisted BESS bids, with the bid's LCOC provided in place of the LCOE.

Table 8
RFP Shortlisted BESS Bids

Project Name	Bidder	Projected In-Service Date (Month/ Year)	Size (MW)	Interconnection	Location	Type	Contingent	Final Score	LCOC Bid Price ($/kW-yr)[52]
								[PROTECTED DATA BEGINS	
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
								PROTECTED DATA ENDS]	
[PROTECTED DATA BEGINS									
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]			[redacted]			PROTECTED DATA ENDS]			

On January 10, 2025, bidders of projects in the Traditional Option were notified of our shortlist decisions; those projects progressed to final contract negotiations.

We also notified bidders with bids shortlisted for additional study under the MNEC Contingent Option, asking them to confirm if they would like to proceed with this opportunity and informed them of the next steps:

- Final MNEC route determined by the Commission.

[52] The LCOEs reflected in the table are based on bid data and RFP evaluation protocol and do not reflect adjustments made after bid selection.

- Bids evaluated for technical feasibility, taking the final MNEC route into consideration.
- Bidders will have an opportunity reprice their bids based on the final MNEC route.
- Final shortlisting of bids.

On April 10, 2025, the Commission verbally approved the MNEC route.[53] Following this approval, we set a deadline of May 15, 2025, for self-builds and May 16, 2025, for third-party bidders to update their bids based on the approved route.

[PROTECTED DATA BEGINS PROTECTED DATA ENDS] project, citing the project's distance from the approved transmission line. The location rendered the project no longer viable due to the increased costs and logistical challenges associated with interconnection.

The **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** project was also located a considerable distance from the MNEC and was ultimately eliminated due to inadequate site control and absence of pricing for the tie-line needed to connect the project to the approved MNEC route.

The final MNEC Contingent shortlist was determined on June 24, 2025, with oversight from the IA confirming that the final MNEC shortlist was appropriate and aligned with the predefined evaluation criteria.

Of the MNEC Contingent projects initially shortlisted, only one – Sherco Solar 4 – was ultimately shortlisted. While we are encouraged to have one viable project on the MNEC moving forward, it is nonetheless disappointing that only one project remained after evaluation. Now that the final MNEC route has been approved, we anticipate broader participation in future RFPs from developers with projects located along the approved route.

[53] In the Matter of the Applications of Xcel Energy for a Certificate of Need and Route Permit for the Minnesota Energy Connection Project in Sherburne, Stearns, Kandiyohi, Wright, Meeker, Chippewa, Yellow Medicine, Renville, Redwood, and Lyon counties in Minnesota, MPUC Docket Nos. E002/CN-22-131 and E002/TL-22-132, Order (June 11, 2025).

F. Five-Year Action Plan

The Company's approved 2024 IRP includes a Five-Year Action Plan that identifies the need for 3,200 MW of wind, 400 MW of solar, and 600 MW of standalone storage for a total of 4,200 MW of capacity to meet our near-term needs. This RFP was conducted to support implementation of that plan and is one of two resource acquisitions currently underway, alongside the Wind Development Transfer RFP in which we have shortlisted approximately 1,800 MW of wind projects with the Independent Auditor's concurrence.[54]

While the Company is currently bringing forward solar and standalone storage projects – and no wind projects – it is important to recognize the need for flexibility given current market challenges, including interconnection delays, inflationary pressures, and evolving tax credit policy. These dynamics influence project viability and timing, requiring the Company to remain adaptable in its resource procurement strategy.

As part of this process, the Company evaluates and brings forward the best projects, prioritizing those that align with system needs and deliver benefits to our customers. This includes ensuring reliability, keeping our customer bills affordable, and maintaining consistency with both the Company and the State's long-term decarbonization goals.

In the next section, we discuss our subsequent work to move projects forward to contract execution.

IV. CONTRACT NEGOTIATIONS AND FINAL PORTFOLIO

On January 10, 2025, we notified all bidders regarding whether their bid had been shortlisted. At that point, the internal firewall, which separated the bid evaluation team from the self-build project team, ended for projects in the Traditional Option, and remained in place for projects in the MNEC Contingent Option. Bidders of projects in the Traditional Option were notified of our shortlist decisions; those projects progressed to contract negotiations. We also informed bidders with projects shortlisted for additional study under the MNEC Contingent Option, asking them to

[54] Docket No. E-002/M-23-342.

confirm if they would like to proceed with this opportunity and informed them of the next steps as described in Section III.

On June 24, 2025, we notified all MNEC Contingent Option bidders regarding whether their bid had been shortlisted.

A. Third-Party Shortlisted Projects

In late January, the Company began initial conversations with the parties whose bids were selected for the shortlist. As described in Section II, the PPAs were negotiated in the context of significant industry-wide cost pressures, including supply chain disruptions, labor shortages, and evolving trade policies. Global supply chain disruptions, growing demand, labor market constraints, higher interest rates, and evolving trade policies are collectively driving up both the cost of project development and operational costs. In response to the unprecedented market uncertainty, the Company ultimately determined it was prudent to permit very limited pricing adjustments during the post-shortlisting phase of our RFP process. Simply put, bidders indicated they could not proceed with their proposed projects at the original bid prices due to the challenges described above and as a result, the overall viability and success of the solicitation was at risk. To ensure continued participation and project viability, we accommodated limited flexibility while maintaining a fair, transparent and consistent approach. These adjustments were carefully managed to preserve the integrity, fairness, and competitiveness of the RFP process. In negotiations, the Company reaffirmed that all projects were still expected to maintain the metrics of their bids and meet the requirements set forth in the RFP.

One requirement of the RFP process was for each bidder to provide a single bid rate that fully complied with all model contract terms; this was required to ensure all bids were being evaluated on a consistent basis. At the negotiation stage, the Company determined it would be appropriate to entertain limited terms that could be negotiated without undermining the RFP integrity to allow these projects the ability to move forward and lessen the risk of additional customer cost increases.

Prior to the start of contract negotiations, **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** determined that it could not maintain its rate proposed in its bid and withdrew **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** from consideration. **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** had not

[PROTECTED DATA BEGINS **PROTECTED DATA ENDS]** rendered the project economically non-viable. Additionally, **[PROTECTED DATA BEGINS** **PROTECTED DATA ENDS]** formally withdrew its bids for the **[PROTECTED DATA BEGINS** **PROTECTED DATA ENDS]**, as the project had secured another off-taker.

B. Selected Projects

At their conclusion, negotiations have resulted in seven solar and five standalone projects, as shown in Tables 9 and 10, that are in the public interest. We describe the projects in Sections V - VIII.

Table 9
Selected Solar Projects[55]

Project Name	Developer	Size (MW)	Inter-connection	Type	Location	LCOE ($/MWh)
Sherco Solar 4	Xcel Energy	200	Transmission - MNEC	Self-Build	Clear Lake Township, Minnesota	**[PROTECTED DATA BEGINS**
Fillmore Solar	NGR	15	Transmission	PPA	Minnesota	
Grant Solar	NGR	99	Transmission	PPA	South Dakota	
Portfolio 1	One Energy	41	Distribution	Build-Transfer	Wisconsin	
Gopher Solar	Ranger	200	Transmission	PPA	Minnesota	
Lemon Hill Solar	Ranger	180	Transmission	PPA	Minnesota	
Portfolio 2	One Energy	33	Portfolio 2	Build-Transfer	Wisconsin	
TOTAL		**768 MW**				**PROTECTED DATA ENDS]**

[55] As previously indicated, the One Energy Portfolio 1 and 2 projects are in Wisconsin and fall under the jurisdiction of the Wisconsin Public Service Commission. Additional details can be found in Section IX.

Table 10
Selected Storage Projects

Project Name	Developer	Size (MW)	Interconnection	Type	Location	LCOC ($/kW-yr)
Blue Lake BESS	Xcel Energy	135.5	Transmission – Blue Lake Interconnection Reuse	Self-Build	Shakopee, Minnesota	**[PROTECTED DATA BEGINS**
Sherco South BESS	Xcel Energy	300	Transmission – Sherco Solar Surplus or ERAS	Self-Build	Becker, Minnesota	
Crowned Ridge BESS	NextEra	120	Transmission	PPA	South Dakota	
Crane BESS	Tenaska	200	Transmission	PPA	Minnesota	
Mayhew Lake BESS	NextEra	100	Transmission	PPA	Minnesota	
TOTAL		**855.5 MW**				**PROTECTED DATA ENDS]**

V. LEASE ARRANGEMENTS

The Company's proposed PPAs are structured to provide reliable, dispatchable capacity at a reasonable cost, with enforceable performance standards and milestone requirements that protect customers from underperformance and cost escalation, as further described in Sections VI-VII.

However, PPAs, particularly those for resources with dispatch rights and capacity-based payments, have the potential to create long-term financial obligations in the form of operating or finance leases, which is the case for some of the projects stemming from this resource acquisition that we are requesting the Commission to approve. When assessing financial risk, credit rating agencies may treat a portion of the future payments due on these lease arrangements, or otherwise 'lease obligations' as *imputed debt*, effectively adding them to the Company's reported debt to get a more complete picture of its financial leverage.

When the credit rating agencies add these debt-like obligations to reported debt, key financial metrics, such as the cash flow to debt ratio, worsen. This change signals higher financial risk and can lead to lower credit ratings, which in turn increase the Company's borrowing costs on new debt. Given the Company's anticipated need to raise several billion dollars of long-term debt financing over the next five years, even marginal changes in the cost of debt will have material and sustained financial impacts on customers. Table 11 below presents the estimated amount of imputed debt and key credit ratio impacts expected by 2028, when all the contracts are active.

Table 11
Estimated Credit Metric Impact

Project	Lease Type	2028 Imputed Debt ($ million)	2028 Impact to FFO / Debt
Crowned Ridge Energy Storage	Operating	$127	Approx. -0.20%
Crane Energy Center	Operating	$257	Approx. -0.50%
Mayhew Lake Energy Storage	Operating	$130	Approx. -0.30%
Total		**$514**	**Approx. -1.00%**

The Company can mitigate the negative impact of incremental imputed debt through two primary avenues. Since ratings agencies closely monitor the relationship between cash flow from operations and total debt, the Company can either: (1) aim to reduce its overall debt burden, or (2) increase its operational cash flow. The debt burden could be reduced by managing the Company to a higher authorized equity ratio. Cash flow could be increased by either increasing return on equity (ROE) or accelerating book depreciation on capital assets. The equity ratio is the most cost-efficient option for managing credit quality, as it reduces the proportion of debt and increases cash flow, while displacing interest expense charged to customers.

Due to the material negative credit quality implications expected as a result of these contracts, the Company intends to propose mitigation through an increase in its equity ratio in its next electric rate case filing.

VI. SOLAR PPAS

This section provides an overview of each solar project – Fillmore, Grant, Gopher State, and Lemon Hill – and payment rate. Additional PPA terms are discussed in Section VIII.

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A. Fillmore Solar Project Overview and Payment Rate

1. Fillmore Solar Project Overview

The Fillmore Solar project is a 45 MW facility located in Fillmore County, Minnesota. Currently, 30 MW of the project is contracted by Xcel Energy, and this proposed PPA covers the remaining 15 MW. National Grid executed the project's GIA on April 21, 2020. The project interconnects into the Cherry Grove Substation, which is owned by Dairyland Power Cooperative. The project began commercial operation on December 13, 2024. Additional project details are summarized in Table 12, and a map depicting the project location is shown in Figure 3, below.

Table 12
Fillmore Solar Project Details

Nameplate Capacity	15 MW
Developer	National Grid Renewables
Project Location	Fillmore County, Minnesota
Project Structure	PPA
COD	January 1, 2026
Contract Term	18 years (aligned with 30 MW portion)
	[PROTECTED DATA BEGINS
Fixed or escalating price	
Levelized price	
Committed Energy	
Approximate Year 1 NCF	
	PROTECTED DATA ENDS]
Estimated construction jobs	N/A
Estimated landowner and local payments*	$4.2 million

** Estimates as provided by project developer for entire 45 MW project.*

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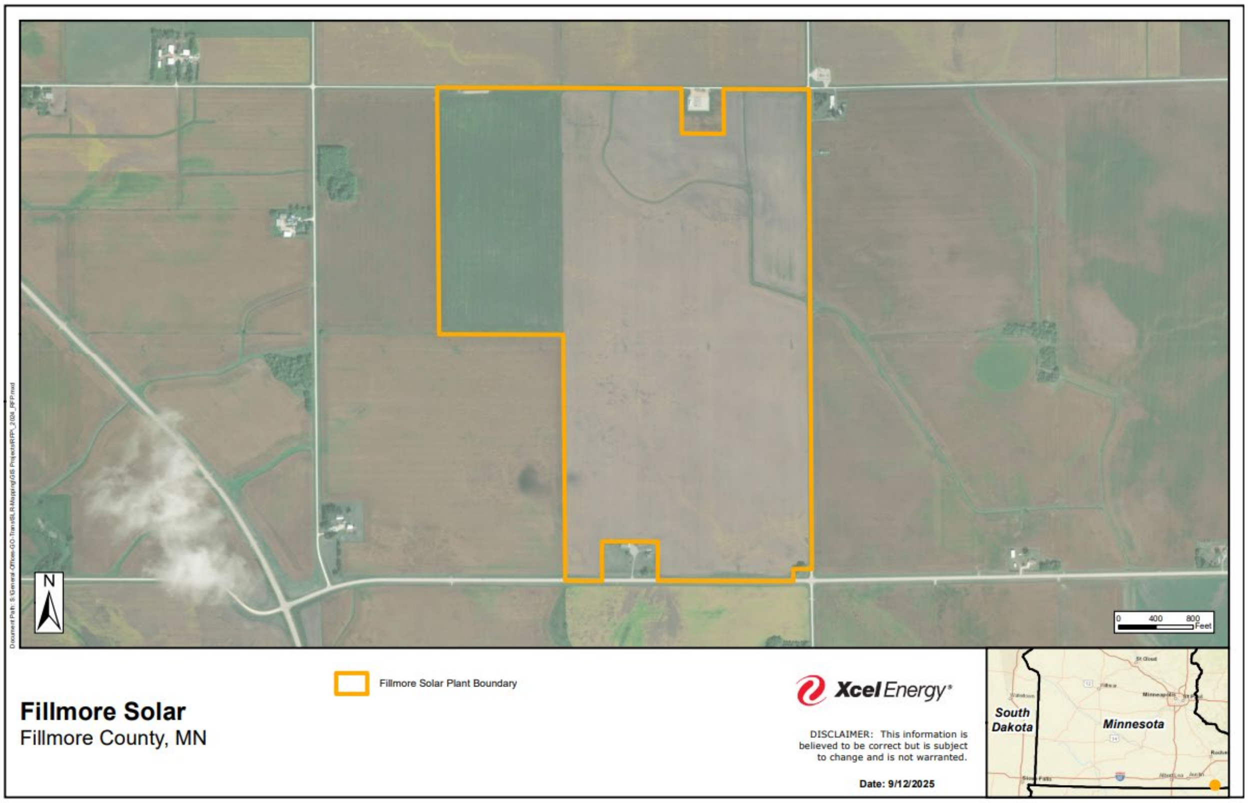
Figure 3
Fillmore Solar Project Location



2. *Fillmore Solar Payment Rate*

The Fillmore Solar PPA provides price certainty for carbon-free solar energy and capacity at a fixed rate of **[PROTECTED DATA BEGINS** **PROTECTED DATA ENDS]** for an 18-year term, aligning with the 30 MW portion of the project. The fixed energy payment is subject to performance adjustment mechanisms described in Section VIII.B and outlined in the PPA included as Attachment G.

B. Grant Solar Project Overview and Payment Rate

1. *Grant Solar Project Overview*

The Grant Solar project is a 99 MW solar development located in McCook County, South Dakota. It has two executed GIAs and plans to interconnect into the Grant

Substation, which is owned by NSP. The project has received a Conditional Use Permit by McCook County and does not require a Facility Permit from the South Dakota Public Utilities Commission or any federal permits. Additional project details are summarized in Table 13, and a map depicting the project location is shown in Figure 4 below.

Table 13
Grant Solar Project Details

Nameplate Capacity	99 MW
Developer	National Grid Renewables
Project Location	McCook County, South Dakota
Project Structure	PPA
Target COD	November 30, 2027
Contract Term	30 years
	[PROTECTED DATA BEGINS
Fixed or escalating price	
Levelized price	
Committed Energy	
Approximate Year 1 NCF	
	PROTECTED DATA ENDS]
Estimated construction jobs*	250
Estimated landowner payments*	$29.6 million
Estimated local tax payments*	$17 million

** Estimates as provided by project developer. Landowner and tax payment figures are total for the contract term.*

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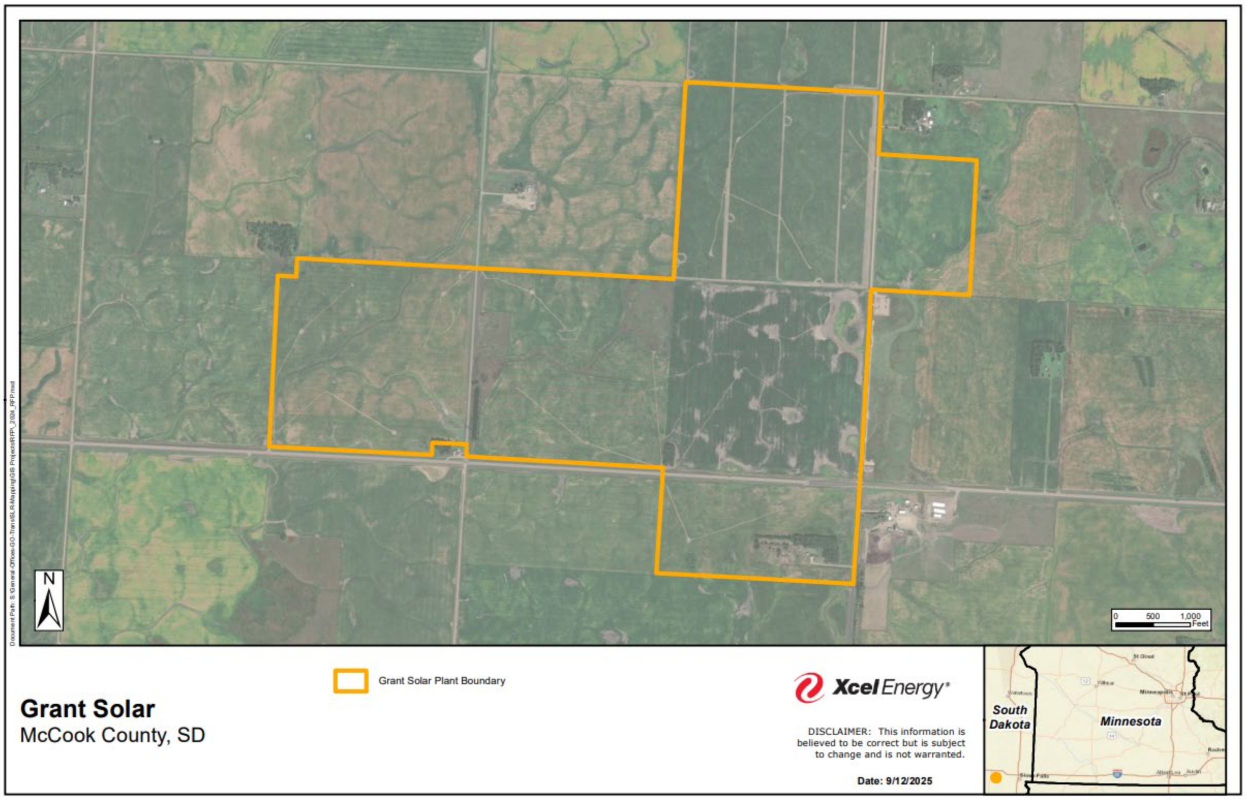
NOT-PUBLIC DATA HAS BEEN EXCISED

Figure 4
Grant Solar Project Location



2. *Grant Solar Payment Rate*

The Grant Solar PPA provides price certainty for carbon-free solar energy and capacity at a fixed rate of **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** for a 30-year term. For "test energy" delivered prior to COD, the Company will pay **[PROTECTED DATA BEGINS PROTECTED DATA ENDS].** The fixed energy payment is subject to performance adjustment mechanisms described in Section VIII.B and outlined in the PPA included as Attachment H.

C. Gopher State Solar Project Overview and Payment Rate

1. *Gopher State Solar Project Overview*

The Gopher State Solar project is a 200 MW solar development located in Renville County, Minnesota. It is part of the MISO DPP 2021 cycle and is expected to have an executed GIA by February 2026. The project plans to interconnect at the Panther Substation, which is owned by Great River Energy. On August 7, 2025, the Minnesota Public Utilities Commission verbally approved the site permit.[56] Additional project details are summarized in Table 14, and a map depicting the project location is shown in Figure 5 below.

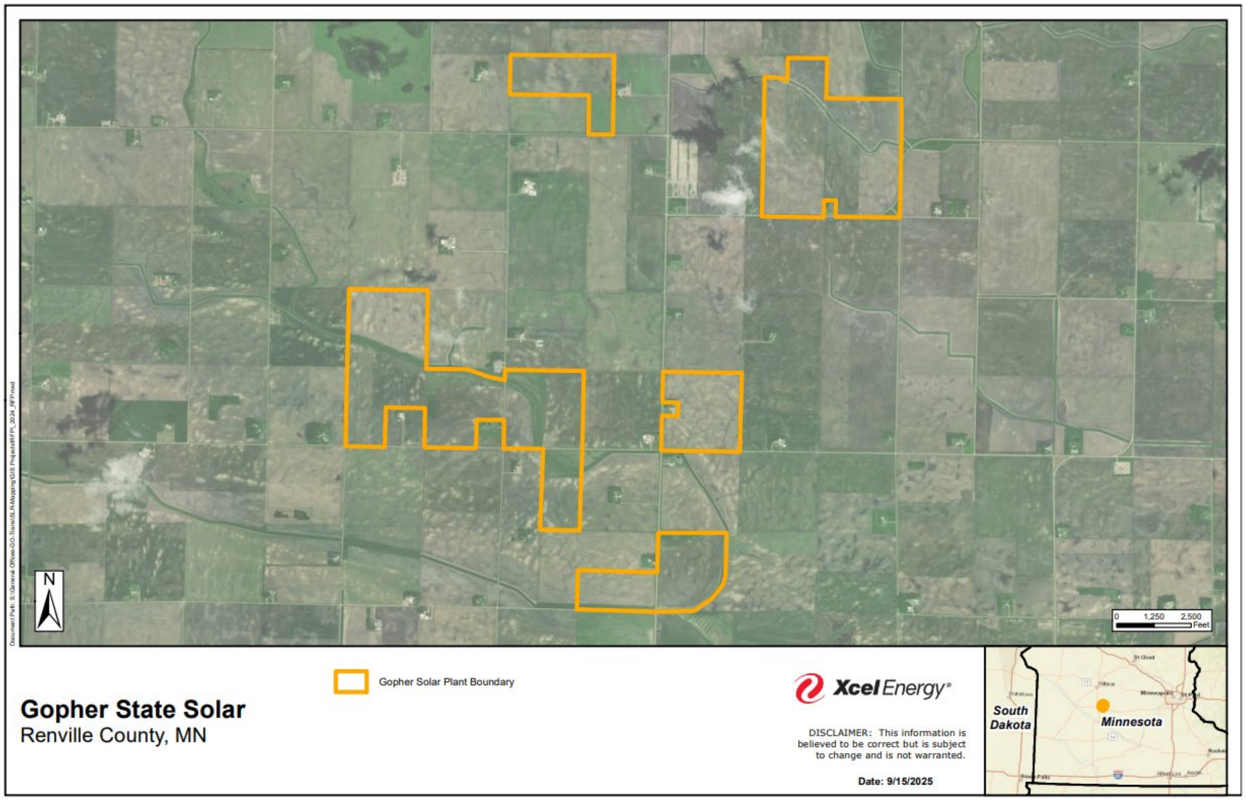
Table 14
Gopher State Solar Project Details

Nameplate Capacity	200 MW
Developer	Ranger Power LLC
Project Location	Renville County, Minnesota
Project Structure	PPA
Target COD	December 31, 2029
Contract Term	30 years
	[PROTECTED DATA BEGINS
Fixed or escalating price	
Levelized price	
Committed Energy	
Approximate Year 1 NCF	
	PROTECTED DATA ENDS]
Estimated construction jobs*	250
Estimated landowner payments*	$59.4 million
Estimated local tax payments*	$35 million

** Estimates as provided by project developer. Landowner and tax payment figures are total for the contract term.*

[56] Docket No. IP-7127/GS-24-106.

Figure 5
Gopher State Solar Project Location



2. *Gopher State Solar Payment Rate*

The Gopher State Solar PPA provides price certainty for carbon-free solar energy and capacity at a fixed rate of **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** for a 30-year term. For "test energy" delivered prior to COD, the Company will pay **[PROTECTED DATA BEGINS PROTECTED DATA ENDS].** The fixed energy payment is subject to performance adjustment mechanisms described in Section VIII.B and outlined in the PPA included as Attachment I.

D. Lemon Hill Solar Project Overview and Payment Rate

1. Lemon Hill Solar Project Overview

The Lemon Hill Solar project is a 180 MW solar development located in Olmsted County, Minnesota. It is part of the MISO DPP-2021 cycle and is expected to have an executed GIA by February 2026. The project plans to interconnect at the161 kV Rochester to Wabaco line owned by Dairyland Power Cooperative. A site permit application for the project was filed with the Minnesota Public Utilities Commission on June 30, 2025.[57] Additional project details are summarized in Table 15, and a map depicting the project location is shown in Figure 6 below.

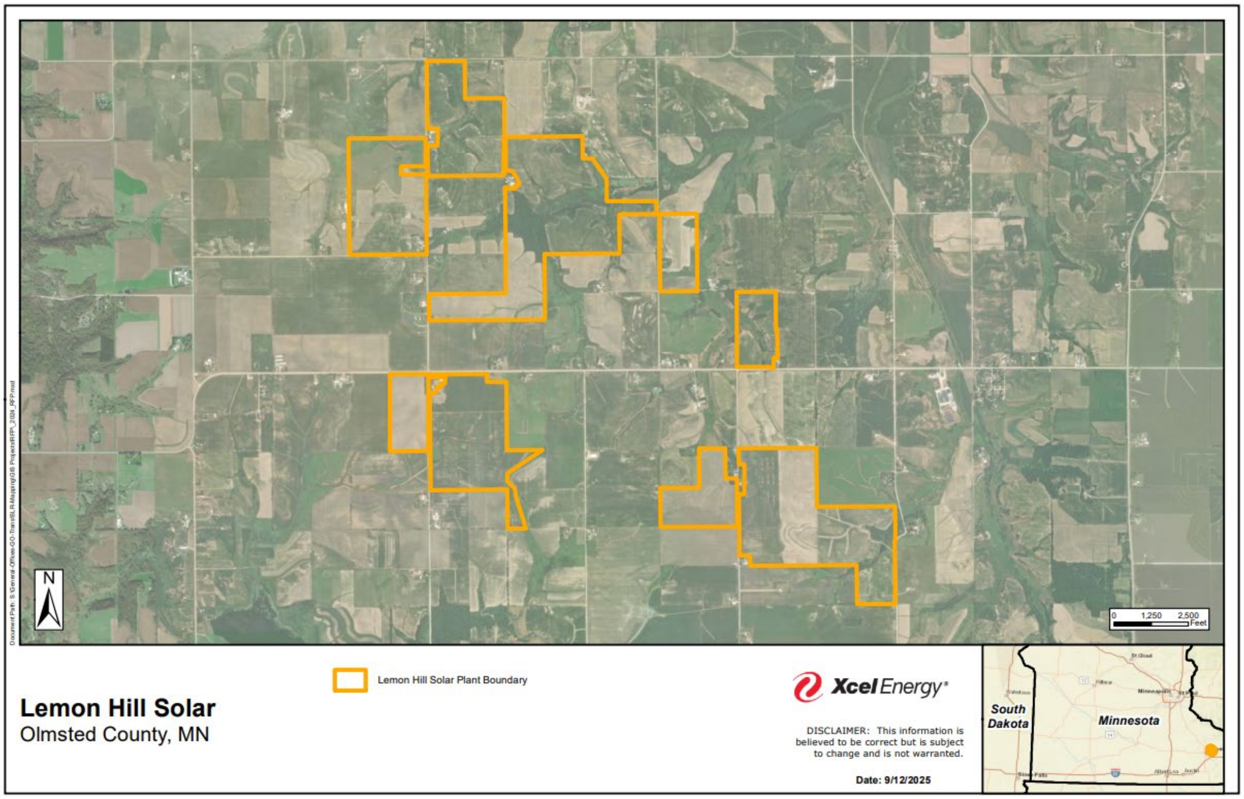
Table 15
Lemon Hill Solar Project Details

Nameplate Capacity	180 MW
Developer	Ranger Power LLC
Project Location	Olmsted County, Minnesota
Project Structure	PPA
Target COD	December 31, 2028
Contract Term	30 years
	[PROTECTED DATA BEGINS
Fixed or escalating price	
Levelized price	
Committed Energy	
Approximate Year 1 NCF	
	PROTECTED DATA ENDS]
Estimated construction jobs*	250
Estimated landowner payments*	$63.6 million
Estimated local tax payments*	$33.1 million

** Estimates as provided by project developer. Landowner and tax payment figures are total for the contract term.*

[57] Docket No. IP-7156/GS-25-126.

Figure 6
Lemon Hill Solar Project Location



2. *Lemon Hill Solar Payment Rate*

The Lemon Hill Solar PPA provides price certainty for carbon-free solar energy and capacity at a fixed rate of **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** for a 30-year term. For "test energy" delivered prior to COD, the Company will pay **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**. The fixed energy payment is subject to performance adjustment mechanisms described in Section VIII.B and outlined in the PPA included as Attachment J.

VII. STORAGE PPAS

This section provides an overview of each BESS project – Crowned Ridge, Crane, and Mayhew Lake – and payment rates. PPA terms applicable only to the Crane project are also discussed below. Additional PPA terms are discussed in Section VIII.

A. Crowned Ridge BESS Project Overview and Payment Rate

1. *Crowned Ridge BESS Project Overview*

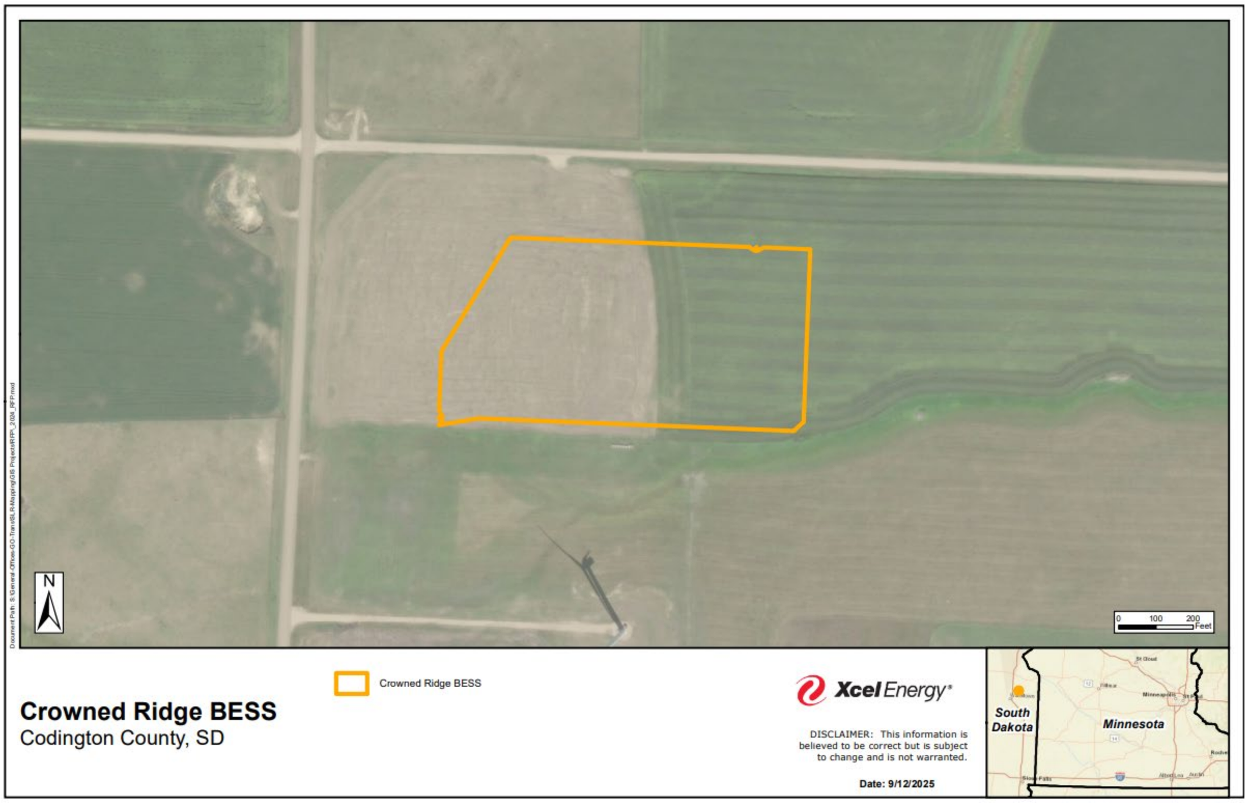
The Crowned Ridge BESS project is a 120 MW/480 MWh surplus battery energy storage development located in Codington County, South Dakota. It expects to have an executed GIA for surplus interconnection capacity associated with the Crowned Ridge wind farm by the end of 2025. The project plans to interconnect into the Big Stone South 230 kV substation, which is owned by the Company. Additional project details are summarized in Table 13, and a map depicting the project location is shown in Figure 7 below. As noted in Table 16, the COD is December 15, 2027. However, under the terms of a Side Agreement included as Attachment K-1, if the South Dakota Public Utilities Commission Facility Permit is not received by August 1, 2026, the COD and other key projects milestones will be extended on a day-for-day basis until the permit is obtained. As a result, the actual COD may shift later than currently planned depending on the timing of permit approval. Further, if the Seller is unable to obtain the Facility Permit by the revised permitting deadline, the Seller has the right to exit the contract for a **[PROTECTED DATA BEGINS** **PROTECTED DATA ENDS]**.

Table 16
Crowned Ridge BESS Project Details

Project Type	BESS
Nameplate Capacity	120 MW / 480 MWh
Developer	NextEra
Project Location	Codington County, South Dakota
Project Structure	PPA
Target COD	December 15, 2027
Contract Terms	15 years
	[PROTECTED DATA BEGINS
Fixed or escalating price	
Capacity Price	
	PROTECTED DATA ENDS]
Estimated construction jobs*	240
Estimated landowner payments*	$975,000
Estimated local tax payments*	$525,000

**Estimates provided by the project developer. Construction job estimate assumes 1-2 temporary workers per 1 MW for the duration of construction.*

Figure 7
Crowned Ridge BESS Project Location



2. *Crowned Ridge BESS Payment Rate*

The 120 MW/480 MWh Crowned Ridge BESS PPA includes fixed capacity payments of **[PROTECTED DATA BEGINS** [redacted] **PROTECTED DATA ENDS]** for a 15-year term. The fixed capacity payment is subject to performance adjustment mechanisms described in Section VIII.B and outlined in the PPA included as Attachment K.

B. Crane BESS Project Overview, Payment Rate, and Special PPA Terms

1. *Crane BESS Project Overview*

The Crane BESS project is a 200 MW / 800 MWh standalone battery energy storage development located in Olmsted County, Minnesota. The project submitted a generator interconnection application in MISO's 2021 DPP Cycle and plans to interconnect into the Byron 161kV substation, which is owned by Southern Minnesota Municipal Power Agency. The DPP 2021 Cycle is schedule to be completed on November 7, 2025, and the project anticipates executing a GIA in the first quarter of 2026. A site permit application was filed with the Commission on March 5, 2025.[58] Additional project details are summarized in Table 17, and a map depicting the project location is shown in Figure 8 below.

Table 17
Crane BESS Project Details

Project Type	BESS
Nameplate Capacity	200 MW/800 MWh
Developer	Tenaska
Project Location	Olmsted County, Minnesota
Project Structure	PPA
Target COD	December 31, 2028, contingent on the execution of a GIA
Contract Terms	15 years
	[PROTECTED DATA BEGINS
Fixed or escalating price	
Capacity Price	
	PROTECTED DATA ENDS]
Estimated construction jobs*	75-100
Estimated landowner payments*	$425,000 (land purchase)
Estimated local tax payments*	$211,300 (property tax)

**Estimates provided by the project developer.*

[58] A joint site permit application was filed for the adjacent Crane Energy Storage and the Sandhill Energy Storage projects in Docket Nos. IP-7148/ESS-24-406 and IP-7149/ESS-24-407.

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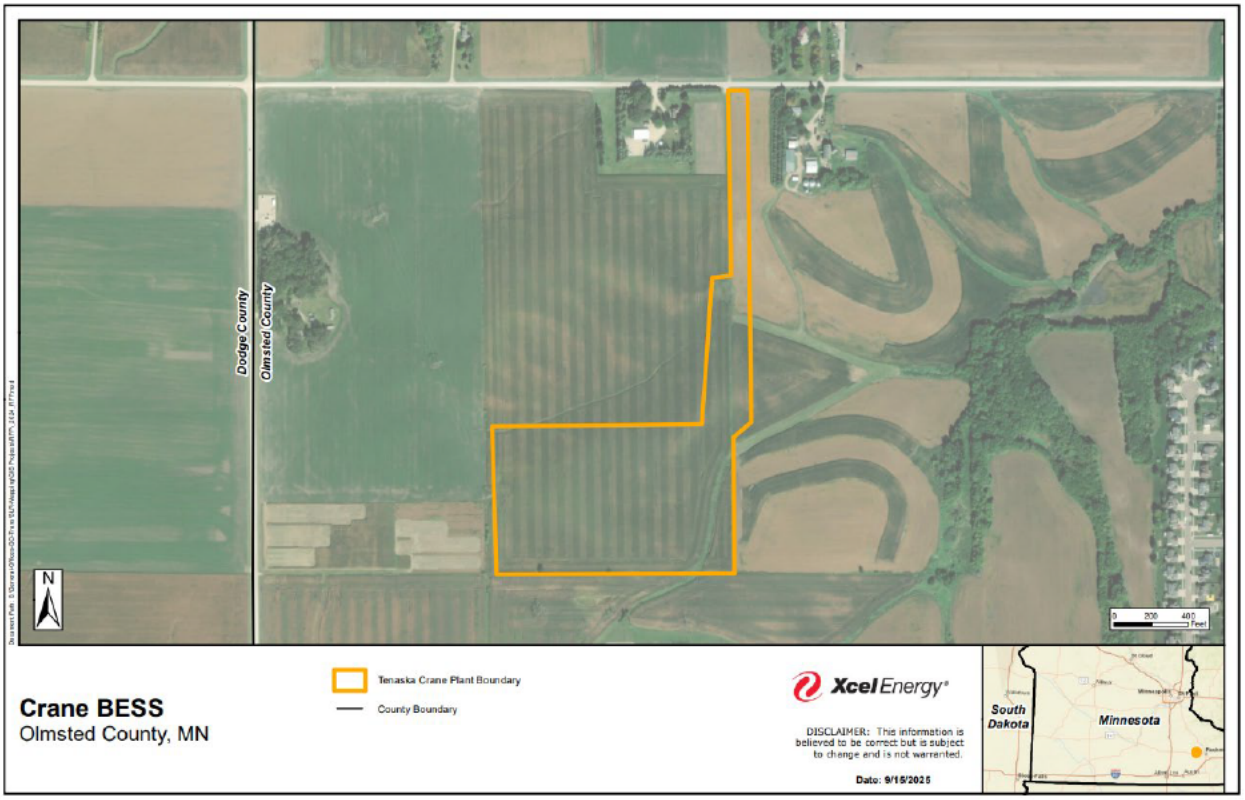
Figure 8
Crane BESS Project Location



2. *Crane BESS Payment Rate*

The 200 MW/800 MWh Crane BESS PPA includes fixed capacity payments of **[PROTECTED DATA BEGINS** [redacted] **PROTECTED DATA ENDS]** for a 15-year term. The fixed capacity payment is subject to performance adjustment mechanisms described in Section VIII.B and outlined in the PPA included as Attachment L. Further, **[PROTECTED DATA BEGINS** [redacted]

[redacted] **PROTECTED DATA ENDS]**.

C. Mayhew Lake BESS Project Overview and Payment Rate

1. Mayhew Lake BESS Project Overview

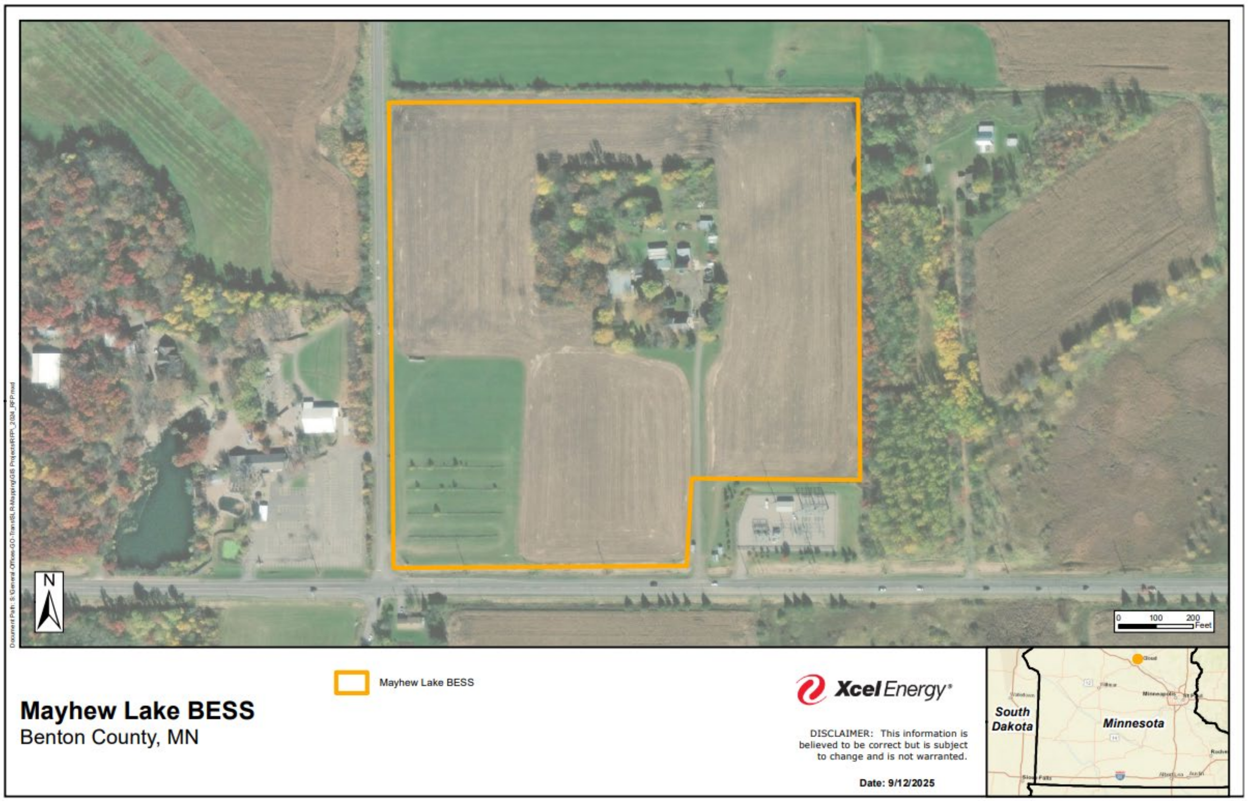
The Mayhew Lake BESS project is a 100 MW/400 MWh standalone battery energy storage development located in Benton, Minnesota. The project has an executed GIA and plans to interconnect into the Mayhew Lake 115 kV substation, which is owned by NSP. Additional project details are summarized in Table 18, and a map depicting the project location is shown in Figure 9 below.

Table 18
Mayhew Lake BESS Project Details

Project Type	BESS
Nameplate Capacity	100 MW / 400 MWh
Developer	NextEra
Project Location	Benton, Minnesota
Project Structure	PPA
Target COD	May 1, 2028
Contract Terms	15 years
	[PROTECTED DATA BEGINS
Fixed or escalating price	[redacted]
Capacity Price	[redacted]
	PROTECTED DATA ENDS]
Estimated construction jobs*	Up to 60 employees per week for up to 15 weeks
Estimated landowner payments*	N/A
Estimated local tax payments*	$42.4 million

**Estimates as provided by the project developer.*

Figure 9
Mayhew Lake BESS Project Location



2. *Payment Rate*

The 100 MW / 400 MWh Mayhew Lake BESS PPA includes fixed capacity payments of **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** for a 15-year term. The fixed capacity payment is subject to performance adjustment mechanisms described in Section VIII.B and outlined in the PPA included as Attachment M.

VIII. PPA TERMS

Through prudent contracting practices and negotiations with developers, we have identified, assessed, and mitigated major risks, while maximizing potential benefits through the contract terms. Below, we outline key terms of our solar and energy storage agreements.

A. Performance Adjustment Mechanisms for Solar Projects

The Grant Solar, Gopher State Solar, and Lemon Hill Solar PPAs include several performance-based adjustment mechanisms that align with the RFP model PPA. These provisions are designed to ensure that each facility delivers reliable, high-quality service and that Seller compensation is closely tied to actual performance. The mechanisms described below are structured to incentivize high availability and energy delivery, provide for flexibility in operational realities, and protect both the Company and our customers from extraordinary risks.

1. *Committed Energy Delivery Adjustment*

Each solar project PPA establishes a "Committed Energy" amount for each Commercial Operation Year. If the Seller fails to deliver a specified percentage of Committed Energy over defined periods (e.g., two consecutive years or three out of six years), the Monthly Energy Payment is reduced by a set percentage. The reduction escalates for repeated or more severe underperformance. This mechanism ensures that Seller compensation is directly linked to actual energy delivery and incentivizes the Seller to maximize output and reliability.

2. *Curtailment and Compensation*

The solar PPAs distinguish between compensable curtailments (where the Seller is compensated for curtailed energy) and non-compensable curtailments (where no compensation is due). Compensable curtailments generally include curtailments directed by the Company for market or operational reasons, while non-compensable curtailments include those due to transmission constraints, force majeure, or regulatory actions. This structure balances operational flexibility with fair compensation for the Seller.

3. *Availability and Operational Performance*

Sellers are required to maintain a minimum equivalent availability reporting factor (typically 90 percent) over defined periods. Failure to meet this standard can trigger default provisions, cure periods, and, if not remedied, termination rights for the Company. This incentivizes the Seller to maintain high operational standards and system reliability.

B. Performance Adjustment Mechanisms for BESS Projects

The Crowned Ridge, Crane, and Mayhew Lake BESS PPAs includes several performance-based adjustment mechanisms that align with the RFP model PPA. These provisions are designed to ensure that the facility delivers reliable, high-quality service and that payments to the Seller are aligned with actual performance. The mechanisms described below are structured to align Seller compensation with actual system performance, incentivize high availability and efficiency, and provide flexibility for operational realities.

1. Capacity Availability Factor (CAF) Adjustment

The monthly capacity payment varies based on the actual availability of the project each month. The CAF reflects the actual available capacity of the battery storage system, adjusted for scheduled maintenance. If the facility is unavailable due to forced outages or underperformance, the Seller's payment will be reduced accordingly. This mechanism incentivizes the Seller to maximize system availability and reliability throughout the contract term.

2. Round Trip Efficiency Adjustment

The contract requires the battery storage system to meet its committed round-trip efficiency (RTE) levels each year. RTE is the ratio of energy discharged compared to energy charged reflecting the efficiency of the project's charging capabilities. If the actual RTE falls below guaranteed levels, the monthly payment is reduced. This ensures that the Seller is financially motivated to maintain the battery's efficiency over time.

3. Excess Throughput

If the battery is discharged above the annual throughput limit, the Seller is entitled to an additional payment for each megawatt-hour (MWh) of excess energy delivered. This structure provides an incentive for the Seller to make the system available beyond its planned throughput, while also protecting the facility from overuse that could degrade the asset.

4. *Penalties for Failure to Respond to Dispatch*

If the Seller fails to accurately or timely respond to a dispatch notice, and the market operator imposes a penalty or charge on the Company as a result, the Company may pass through those charges to the Seller by reducing the next monthly payment.

C. Key PPA Terms Common Across Project Types

Key PPA terms common across both solar and storage PPAs are described below.

1. *Critical Path Development Milestones*

The PPAs require the achievements of certain milestones – referred to as "Critical Path Development Milestones" – that are critical to the successful and timely development of the project. If a project misses, or is anticipated to miss, a critical milestone, the Seller must establish a recovery plan to restore the project's schedule. Failure to meet these milestones by the specified deadline will result in liquidated delay damages. Further, if a project does not achieve COD by its target date, it will again be subject to liquidated delay damages. In the event a project fails to achieve COD altogether, the Company can terminate and collect damages for termination.

2. *Security Fund*

Our PPAs require Sellers to fund and maintain security in favor of the Company following execution and throughout development and the term of the contract (Security Fund). The Company may draw from this Security Fund to recover amounts owed to the Company for liquidated delay damages, actual damages, and liquidated damages for failure to reach the Critical Path Development Milestones or failure to achieve COD.

3. *Resource Attributes Conveyed to the Company*

Our PPAs also ensure that the Company receives all energy, capacity, and environmental attributes from each Project. This ensures that the Company is able to count the project's accredited capacity toward our planning requirements and we receive any and all Renewable Energy Credits (RECs) created by the project, which can be used counted toward our compliance with Minnesota's Eligible Energy Technologies Standard,[59] Carbon-Free Standard, and Solar Energy Standard.

4. Labor

The RFP required all bidders to utilize union labor for the construction of the facility, and such remains a provision of the proposed PPAs as well.

D. Relief Mechanisms Associated with Geopolitical Uncertainty

As detailed above, the industry is facing tremendous uncertainty. This unprecedented uncertainty includes trade measures, tariff imposition, tax credits, tax qualifications, federal permitting, import restrictions and foreign entity concerns just to name a few. As such, the Company recognizes that granting practical and limited relief mechanisms in an effort to stabilize and promote the continued development of new resources is necessary and prudent at this time. Generally, the Company determined that three primary components are driving project geopolitical uncertainty currently. First, ever-changing tariffs and trade measures make it very challenging to lock-in definitive equipment costs for project development. Second, the uncertainty surrounding tax incentives for renewable energy development has made modeling a project's economics very challenging without taking on significant financial risk. And third, federal action challenging project permitting not only threatens a project's schedule but ultimately could prevent a project from being constructed all-together.

In consideration of the above, each of the new construction resources in this portfolio – essentially, the entire portfolio except for Fillmore Solar, which is already in operation – has been granted the relief mechanisms described below. The relief incorporates a comprehensive set of mechanisms and safeguards designed to address regulatory uncertainty, evolving reliability standards, and macroeconomic disruptions. These relief mechanisms provide a balanced framework that protects both the Seller and the customer from extraordinary external risks while maintaining project viability and ensuring timely delivery of contracted services. The relief mechanisms are consistent with those offered to all selected bidders in the RFP as well as the Company's other current resource solicitations in front of this commission.[60]

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[59] Formerly known as the Renewable Energy Standard.

[60] This approach aligns with Commission Orders in other similar matters. *See* In the Matter of the Petition of Northern States Power Company, d/b/a Xcel Energy, for Approval of Sherco Solar 3 and Apple River Solar

1. Specified Change in Tax Law

If a change in tax law (for example, a repeal of a clean energy tax credit) prevents the Seller from realizing investment or production tax credit benefits and the financial impact exceeds a material threshold relative to the size of each project, then Seller has the opportunity to exit the contract, forfeiting a portion of the Security Fund. Prior to termination, both parties must engage in a 90-day negotiation period to amend the PPA in an effort to continue with the project prior to terminating. The Seller can be granted up to 75 days of COD delay during the process. Any such change in tax law triggering the relief is subject to verification by an Independent Auditor.

2. Extraordinary Federal Action

If the Seller is unable to reach COD due to a federal permit being withheld or denied, the Seller is granted a day-for-day extension. For example, if a presidential executive order causes the delay or otherwise makes construction impossible, then the Seller may extend their planned in-service dates to allow additional time to obtain such permit. If the delay continues and COD still cannot be achieved within a year, then either party has the opportunity to exit the contract without penalty.

3. New Trade Measure Event

If a new or modified import tariff is imposed on the project's major components, the Seller may request a rate increase capped at no more than 20 percent to account for the new tariff impact. Each new tariff and requested rate increase must be verified by an Independent Auditor. The Independent Auditor shall be granted the opportunity to review Seller's major equipment and determine the validity and impact of any new tariff. If the Independent Auditor denies the new tariff, or if Seller's calculation of the rate increase is determined by the Independent Auditor as materially inaccurate or otherwise in bad faith, no rate increase will be granted. The Seller has the right to submit multiple requests for different tariff events and is granted up to 75 days of COD delay during the review process. If the Independent Auditor verifies the new

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Power Purchase Agreement, Docket No. E002/M-22-403 at Order Point 5a (October 23, 2023) and In the Matter of the Petition of Minnesota Power for Approval of Investments and Expenditures in the Boswell Solar Projects for Recovery through Minnesota Power's Renewable Resources Rider under Minn. Stat. § 216B.1645, at Order Point 5 (May 13, 2025).

tariff event and also verifies Seller's calculation of the rate increase, then the rate increase will be automatically applied to the PPA for the remainder of the term.

IX. SOLAR BUILD-TRANSFERS

In this section, we provide an overview of the two One Energy build-transfer solar projects. We are currently still working to finalize the terms of the build-transfer agreements. For contractual purposes, there will ultimately be three build-transfer agreements covering the portfolio projects below. The component projects will remain the same. Because the One Energy solar projects are located in Wisconsin, Xcel Energy's Wisconsin Operating Company, NSPW, is the party to the One Energy projects. NSPW will seek any necessary project approvals from the Public Service Commission of Wisconsin.

A. One Energy Portfolio 1

The One Energy Portfolio 1 project consists of six distributed photovoltaic solar energy facilities totaling 41 MW, located in Clark County, Wisconsin. Four, 7.5 MW sites will interconnect at the T-Corners substation and two, 5.5 MW sites will interconnect at the Grassland substation, each owned by NSPW. NSPW has approved the proposed interconnection of each facility under Chapter PSC 119 of the Wisconsin Administrative Code, contingent upon required distribution system and substation upgrades. Additional project details are summarized in Table 19.

Table 19
One Energy Portfolio 1 Solar Project Details

Nameplate Capacity	Portfolio 1 Total: 41 MW *Black River: 5.5 MW* *Rock Creek: 5.5 MW* *Ox Eye 1: 7.5 MW* *Ox Eye 2: 7.5 MW* *Ox Eye 3: 7.5 MW* *Ox Eye 4: 7.5 MW*
Developer	One Energy
Project Location	Clark County, Wisconsin
Project Structure	Build-Transfer
Anticipated COD	Q2 2028

	[PROTECTED DATA BEGINS
Fixed or escalating price	
Levelized price	
Committed Energy	
Approximate Year 1 NCF	
	PROTECTED DATA ENDS]
Estimated construction jobs*	50
Estimated landowner payments*	$10.96 million
Estimated local tax payments*	$480,000

** Estimates as provided by project developer. Landowner and tax payment figures are total for the contract term.*

B. One Energy Portfolio 2

The One Energy Portfolio 2 project consists of six distributed photovoltaic solar energy facilities totaling 33 MW, located in Barron County, Pepin County, and Jackson County, Wisconsin. The six, 5.5 MW projects will interconnect with each of the following substations: Twin Town, Alma Center, Eau Galle, Ridgeland, Arkansaw, and Rice Lake, each owned by NSPW. NSPW has approved the proposed interconnection of each facility under Chapter PSC 119 of the Wisconsin Administrative Code, contingent upon required distribution system and substation upgrades. Additional project details are summarized in Table 20.

Table 20
One Energy Portfolio 2 Solar Project Details

Nameplate Capacity	Portfolio 2 Total: 33 MW *Jera: 5.5 MW* *Meadows Creek: 5.5 MW* *Plum Creek: 5.5 MW* *Silver Birch: 5.5 MW* *South Fork: 5.5 MW* *Verbena 2: 5.5 MW*
Developer	One Energy
Project Location	Wisconsin
Project Structure	Build-Transfer

Anticipated COD	December 31, 2027
	[PROTECTED DATA BEGINS
Fixed or escalating price	
Levelized price	
Committed Energy	
Approximate Year 1 NCF	
	PROTECTED DATA ENDS]
Estimated construction jobs*	50
Estimated landowner payments*	$6.75 million
Estimated local tax payments*	$480,000

** Estimates as provided by project developer. Landowner and tax payment figures are total for the contract term.*

X. COMPANY SELF-BUILDS

A. Blue Lake BESS

This section outlines the Blue Lake BESS self-build project, proposed on September 17, 2024, ahead of external RFP bids and detailed in our September 25, 2024 Letter in this docket.

1. *Blue Lake BESS Project Overview*

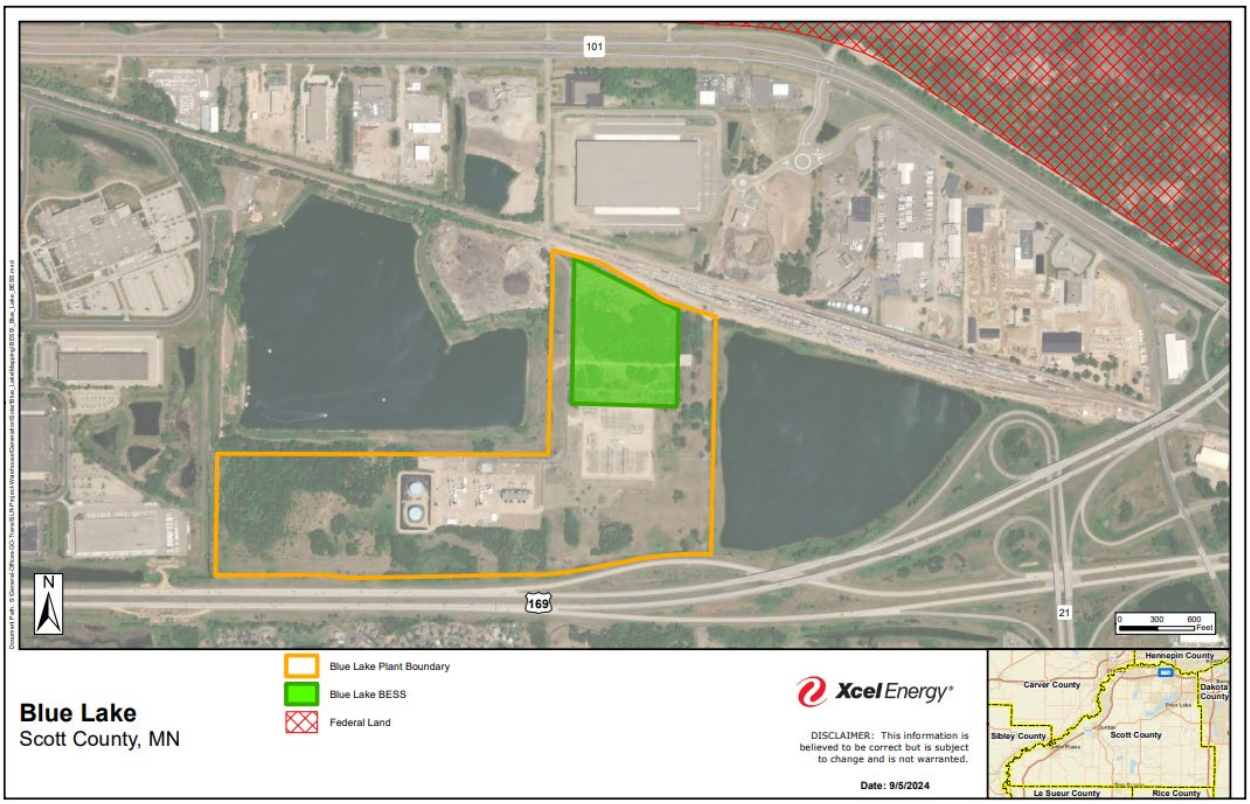
Table 21
Blue Lake BESS Project Details

Nameplate Capacity	135.5 MW/542 MWh BESS
Developer	Xcel Energy
Project Location	Shakopee, Minnesota
Project Structure	Self-Build
Anticipated COD	Q2 2027
Project Life	20 years
	[PROTECTED DATA BEGINS
LCOC ($/kW-yr)	
	PROTECTED DATA ENDS]
Estimated construction jobs created	55
Estimated landowner payments*	N/A
Estimated local tax payments*	$60 million

** Construction jobs estimated at peak construction activity. Total payments over the life of the project.*

The 135.5 MW/542 MWh Blue Lake BESS MW Project is being developed by Xcel Energy and will be located on approximately 12 acres of existing Company-owned property, directly north of Blue Lake Substation in Shakopee, Minnesota. Figure 10 shows the location of the Blue Lake Substation and the surrounding Blue Lake BESS site.

Figure 10
Blue Lake Site and Blue Lake BESS Location



The project proposes to interconnect into the Blue Lake Substation and is intended to replace retiring generation at the Blue Lake Generating Station. The Blue Lake Energy Storage project will involve the installation of approximately 33 BESS blocks. Each BESS block consists of four individual battery units or containers. Each BESS block is equipped with a medium-voltage (MV) transformer skid, which integrates an auxiliary transformer and meter to supply power for the site's auxiliary equipment. After voltage is stepped up at each BESS block, the MV cabling is collected in the Project substation. There, the voltage is further stepped up to the transmission level voltage of 115 kV through the Main Power Transformer, which is included as part of the Project.

The critical path to beginning field construction work requires Commission approval of the Site Permit, which was filed on June 20, 2025.[61] During the permitting process, we will finalize procurement of the BESS equipment and a Balance of Plant (BOP) Contractor to complete the final Engineering, Procurement, and Construction (EPC) of the project. The BOP Contractor will take the project's development engineering design and finalize the facility design pursuant to the Company's technical specifications and scope of work and begin construction after the Site Permit is approved and issued. The BOP Contractor will also procure any remaining plant equipment that is necessary and execute sub-contractor agreements.

The Company is anticipating permit approval and post-compliance filings in the first quarter of 2026 and construction to begin in the second quarter of 2026 with a COD in the second quarter of 2027.

2. *Blue Lake BESS Project Costs*

Total capital cost for the Blue Lake BESS Project is estimated at approximately **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**, which includes AFUDC. The projected LCOC for the Blue Lake BESS Project is **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**.

Additionally, as a Company-owned project, Blue Lake BESS is well-positioned to take advantage of standalone storage Investment Tax Credit (ITC) provisions in the IRA, to the direct benefit of our customers. We expect the project to qualify for the standard 30 percent ITC value. As the Company has noted in other dockets, these estimates are dependent upon our current interpretation of IRS guidance and expectations regarding the ITC transfer market, but we are committed to returning the value of all tax credits the Company receives, net of any transaction costs, to our customers.

[61] Docket No. E002/ESS-25-214.

B. Sherco South BESS

This section outlines the Sherco South BESS self-build project, proposed on September 17, 2024, ahead of external RFP bids and detailed in our September 25, 2024 Letter in this docket.

1. Sherco South BESS Project Overview

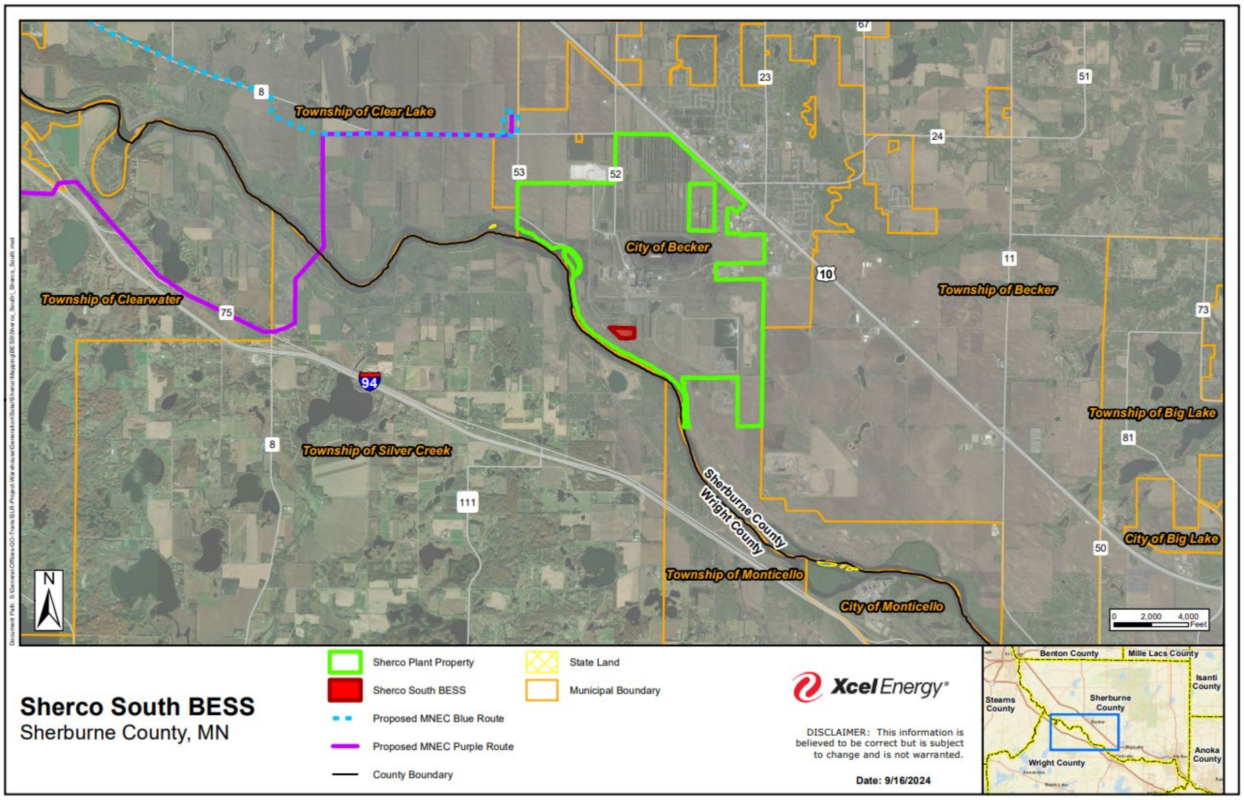
Table 22
Sherco South BESS Project Details

Nameplate Capacity	300 MW/1,200 MWh BESS
Developer	Xcel Energy
Project Location	Becker, Minnesota
Project Structure	Self-Build
Anticipated COD	Q4 2027
Project Life	20 years
	[PROTECTED DATA BEGINS
LCOC ($/kW-yr)	
	PROTECTED DATA ENDS]
Estimated construction jobs created	85
Estimated landowner payments*	N/A
Estimated local tax payments*	$117 million

** Construction jobs estimated at peak construction activity. Total payments over the life of the project.*

The 300 MW/1,200 MWh Sherco South BESS MW Project is being developed by Xcel Energy and will be located on approximately 25 acres of existing Company-owned property, directly south of Sherco Generating Station in Becker, Minnesota. Figure 11 shows the location of the Sherburne County Substation and the surrounding Sherco South BESS site.

Figure 11
Sherco Site and Sherco South BESS Location



The project proposes to interconnect into the Sherburne County Substation and is one of the projects intended to replace retiring generation at the Sherburne County Generating Station via surplus interconnection service.[62] The Sherco South Energy Storage project will involve the installation of approximately 72 BESS blocks. Each BESS block consists of four individual battery units or containers. Each BESS block is equipped with an MV transformer skid, which integrates an auxiliary transformer and meter to supply power for the site's auxiliary equipment. After voltage is stepped up at each BESS block, the MV cabling is collected in the Project substation. There, the voltage is further stepped up to the transmission level voltage of 345 kV through the Main Power Transformer, which is included as part of the Project.

[62] As indicated in our September 12, 2025 Update Letter in Docket No. E002/RP-24-67, the Company submitted an Expedited Resource Addition Study (ERAS) application to MISO for the Sherco South BESS project on August 6, 2025. A separate GIA with MISO would provide valuable accredited capacity for this resource, strengthening its role in overall resource adequacy, but the project would also incur additional network upgrade costs. The Company anticipates filing a petition for Commission approval of certain ERAs projects in the coming weeks and will include any updates on this project in that filing.

The critical path to beginning field construction work requires Commission approval of the Site Permit, which we plan to file in November 2025. During the permitting process, we will finalize procurement of the BESS equipment and a Balance of Plant (BOP) Contractor to complete the final Engineering, Procurement, and Construction (EPC) of the project. The BOP Contractor will take the project's development engineering design and finalize the facility design pursuant to the Company's technical specifications and scope of work and begin construction after the Site Permit is approved and issued. The BOP Contractor will also procure any remaining plant equipment that is necessary and execute sub-contractor agreements.

The Company is anticipating site permit approval and post-compliance filings in the second quarter of 2026 and construction to begin in the third quarter of 2026 with a COD in the fourth quarter of 2027.

2. Sherco South BESS Project Costs

Total capital cost for the Sherco South BESS Project is estimated at approximately **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**, which includes AFUDC. The projected LCOC for the Sherco South BESS Project is **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**.

Additionally, as a Company-owned project, Sherco South BESS is well-positioned to take advantage of standalone storage Investment Tax Credit (ITC) provisions in the IRA, to the direct benefit of our customers. We expect the project to qualify for the standard 30 percent ITC value and an additional 10 percent bonus for being located in an energy community. As the Company has noted in other dockets, these estimates are dependent upon our current interpretation of IRS guidance and expectations regarding the ITC transfer market, but we are committed to returning the value of all tax credits the Company receives, net of any transaction costs, to our customers.

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C. Sherco Solar 4

This section outlines the Sherco Solar 4 self-build project, proposed on September 17, 2024, ahead of external RFP bids and described in our September 25, 2024 Letter in this docket.

1. *Sherco Solar 4 Project Overview*

Table 23
Sherco Solar 4 Project Details

Nameplate Capacity	200 MW
Developer	Xcel Energy
Project Location	Clear Lake Township, Minnesota
Project Structure	Self-Build
Anticipated COD	October 2029
Project Life	35 years
	[PROTECTED DATA BEGINS
LCOE ($/MWh)	
Net Capacity Factor	
	PROTECTED DATA ENDS]
Estimated construction jobs created	300
Estimated landowner payments*	$67.9 million
Estimated local tax payments*	$22.9 million

** Construction jobs estimated at peak construction activity. Total payments over the life of the project.*

The 200 MW Sherco Solar 4 Project is being developed by Xcel Energy and is located on an approximately 1,100-acre site located about one mile north of Clear Lake, Minnesota. Figure 12 shows the location of Sherco Solar 4 and the surrounding Sherco site.

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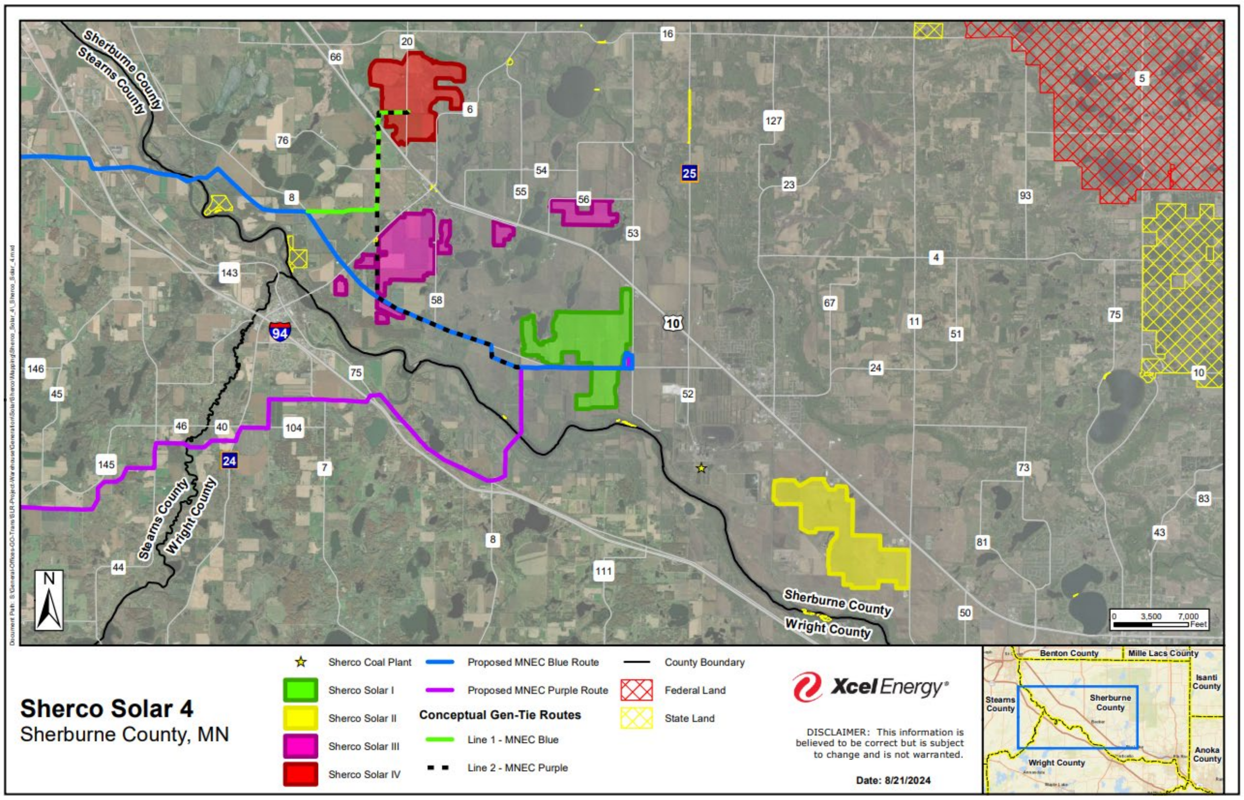
Figure 12
Sherco Site and Sherco Solar 4 Location



The proposed project is the fourth phase of the Sherco Solar projects. Sherco Solar 4 is proposed to interconnect into the Minnesota Energy Connection transmission line utilizing the 200 MW interconnection queue position J1605. Sherco Solar 4 will be located to the north of Sherco Solar 3 and approximately three miles from that project's collector substation, covering approximately 1,100 acres of leased land that is non-prime farmland. Altogether, Sherco Solar 4 will include the installation of approximately 430,000 solar panels and 56 invertors, underground collection feeder lines, access roads, fencing, and a collector substation, among other supporting solar farm infrastructure.

We expect our primary construction activities on the Sherco Solar 4 project will occur in 2028 and 2029 with engineering and most procurement occurring in 2026 and 2027. Under the current estimated schedule, we anticipate that commercial operation will be achieved in October 2029.

The critical path to beginning field construction work requires Commission approval of the Site and Route Permits, which we anticipate filing in March 2026. During the permitting process, we will finalize procurement of the PV modules, inverters, and a BOP Contractor to complete the final EPC of the project. The BOP Contractor will take the project's development engineering design and finalize the facility design pursuant to the Company's technical specifications and scope of work and begin construction after the Site Permit is approved and issued. The BOP Contractor will also procure any remaining plant equipment that is necessary and execute sub-contractor agreements.

2. Sherco Solar 4 Project Costs

Total capital costs for the Sherco Solar 4 Project are currently estimated at approximately **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**, which includes AFUDC. The projected LCOE for the Sherco Solar 4 Project is **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**. Sherco Solar 4's expected NCF **[PROTECTED DATA BEGINS PROTECTED DATA ENDS**

Additionally, as a Company-owned project, Sherco Solar 4 is well-positioned to take advantage of the solar ITC provisions in the IRA, to the direct benefit of our customers. We expect the project to qualify for the standard 30 percent ITC value and an additional 10 percent bonus for being located in an energy community. As the Company has recently noted in other dockets, these estimates are dependent upon our current interpretation of IRS guidance and expectations regarding the tax credit transfer market, but we are committed to returning the value of all tax credits the Company receives, net of any transaction costs, to our customers.

3. Authorization to Acquire Land Rights for Sherco Solar 4

Attachment N includes a fully executed Asset Purchase Agreement (APA) for the property rights of 1,132.61 acres from a subsidiary of NG Renewables to be used for the Sherco Solar 4 project.[63] In this section, we discuss the statute and rules governing our acquisition of land rights for the proposed Sherco Solar 4.

[63] The real property will be leased.

a. Minn. Stat. § 216B.50

Minn. Stat. § 216B.50 governs the transfer of utility assets exceeding $1,000,000:

> *No public utility shall sell, acquire, lease, or rent any plant as an operating unit or system in this state for a total consideration in excess of $1,000,000 . . . without first being authorized so to do by the commission. . . . If the commission finds that the proposed action is consistent with the public interest, it shall give its consent and approval. . . . In reaching its determination, the commission shall take into consideration the reasonable value of the property, plant, or securities to be acquired or dispatched of, or merged and consolidated.*

We respectfully request that the Commission find that our proposed acquisition of the land rights for Sherco Solar 4 is in the public interest for the reasons discussed throughout this filing, and thus complies with Minn. Stat. § 216B.50.

b. Minn. R. 7825.1800

Acquisitions of property also are governed by Minn. R. 7825.1800, subps. B, C, and D of which state that petitions to acquire property shall contain the following:

> *B. Petitions for approval of a transfer of property shall be accompanied by the following: all information as required in part 7825.1400, items A to J; the agreed upon purchase price and the terms for payment and other considerations.*
>
> *C. A description of the property involved in the transaction including any franchises, permits, or operative rights, and the original cost of such property, individually or by class, the depreciation and amortization reserves applicable to such property, individually or by class. If the original cost is unknown, an estimate shall be made of such cost. A detailed description of the method and all supporting documents used in such estimate shall be submitted.*
>
> *D. Other pertinent facts or additional information that the commission may require.*

Below we discuss compliance with this rule and respectfully request that the Commission waive application of Minn. R. 7825.1800, subp. B, consistent with prior similar acquisitions.

c. Minn. R. 7825.1800, subp. B – Variance Request

Minn. R. 7825.1800, subp. B requires detailed information (items A through J) set forth in Minn. R. 7825.1400. That rule—entitled, Filing Requirements for Capital Structure Approval—however, concerns capital structure filings and is geared toward the issuance of securities, which is not at issue here.

Accordingly, we respectfully request that the Commission waive application of Minn. R. 7825.1800, subp. B. The Commission has previously granted a variance to the requirements to provide the information outlined under Minn. R. 7825.1400 (A)-(J) in proposed acquisition of property transactions. The Commission has found that Minn. R. 7825.1400 is applicable to capital structure filings and, therefore, the information does not pertain to petitions to acquire property. The Company respectfully requests a similar variance in this case pursuant to Minn. R. 7829.3200. Minn. R. 7829.3200 allows the Commission to vary its rules if it finds:

> *(a) Enforcement of the rule would impose an excessive burden upon the applicant or others affected by the rule;*
> *(b) Granting the variance would not adversely affect the public interest; and*
> *(c) Granting the variance would not conflict with standards imposed by law.*

The Company can satisfy all three elements. First, as noted above, the proposed transaction does not implicate the information sought by Minn. R. 7825.1400 (A)-(J) and, thus, its provision would impose an excessive burden on the Company. Second, because the proposed transaction does not involve the issuance of securities, granting a variance does not conflict with the public interest. Third, as evidenced by previous Commission precedent waiving these requirements under similar circumstances, a waiver will not violate any standards imposed by law.

With regard to Minn. R. 7825.1800, subps. C and D, we provided applicable project cost and other pertinent information above, and the APA. We note depreciation and amortization reserves do not apply to this transaction for land rights.

XI. ECONOMIC ANALYSIS

In order to determine the benefits provided by the projects in the selected portfolio, the Company conducted an additional economic analysis using updated EnCompass modeling. While our resource plan supports this acquisition, updated analysis was necessary due to changing market conditions.

A. Model Updates Incorporated for Analysis

The updated base case builds on the EnCompass modeling submitted in the Lyon County CT Certificate of Need (CON) filing as described in Section III.E.3 with appropriate changes to modeling inputs and assumptions to reflect the update of important input assumptions and the continued refinement of our modeling practices. Specifically, we updated the model for the following:

- **Firm Dispatchable Resource Updates:**
  Consistent with the Lyon County CT CON modeling and our approved IRP Settlement Agreement, the model includes the Lyon County CT, Cannon Falls PPA extension, MEC 1 PPA extension with BESS, North Star Battery, and Sherco West battery. No additional generic CT additions were available before 2030. Plum Creek wind and Lake Wilson Solar and Storage were removed to reflect the current resource mix.

- **Updated Load Forecast:**
  The Company's Fall 2025 load forecast is used as part of the base assumption in this modeling analysis. The forecast assumes adoption of Electric Vehicle (EV), new Large Commercial & Industrial (C&I) customer additions, Beneficial Electrification (BE), and demographic/economic growth. These load increases are netted against reductions in consumption resulting from Energy Efficiency to result in an overall energy requirements outlook that increases two percent per year in the 2026-2055 timeframe.

- **Updated Generic Resource Pricing with OBBBA refresh starting in 2025:**
  As noted above, the generic resource pricing used in the IRP no longer reflects current market conditions. Updated cost assumptions for new generic wind, solar, CT, and battery resources incorporate the latest market data and consultant estimates, along with changes to tax credits stemming from the OBBBA starting in 2025. These updates ensure the modeling reflects current

pricing and incentive structures to confirm the resource need identified in the resource plan and to improve the accuracy of resource selection and portfolio optimization.

- **Constraint applied to comply with the 100x40 CFS:**
  The model includes a constraint to ensure compliance with Minnesota's 100 percent carbon-free electricity standard by 2040 (CFS), shaping resource selection and dispatch to prioritize carbon-free technologies. We note that in the last resource plan, our modeling results showed compliance with the CFS without imposing a constraint. However, when the updated assumptions were included in the model, it was necessary to include a constraint on carbon emissions to develop a plan that complies with the CFS.

- **Open capacity purchase at CONE and energy purchase before 2030:**
  Prior to 2030, the model allows for open market purchases of capacity at MISO's current Cost of New Entry (CONE) and energy from the market reflecting an alternative that may be theoretically available to the Company in the absence of the portfolio projects. Further, unlike an assumed generic or alternative contract/project life extension, it is a cost that is publicly known and can be easily sized by the model in order to balance reserve margin needs while solving for the least-cost generation mix. This assumption was necessary to develop the baseline capacity expansion plan.

- **The expansion plan is optimized with generic resources starting in 2030:**
  Beginning in 2030, the model shifts to optimizing the resource expansion plan using generic resources rather than relying on market purchases. This approach ensures that the plan is robust and aligned with long-term reliability and carbon reduction requirements.

- **Market capacity and energy purchases are closed beginning in 2030:**
  After 2030, the model no longer allows market purchases of capacity or energy to meet system needs. All requirements must be met through owned or contracted resources within the portfolio, reducing exposure to market volatility and ensuring compliance with future regulatory requirements. This assumption was necessary to develop the baseline capacity expansion plan.

To complete the baseline, we removed 1,600 MW of generic resources in 2025 through 2030 to create a capacity void, locking in the remaining generic resources prior to 2030 and the 400 MW of generic solar at King in 2030 consistent with the approved resource targets in our last resource plan.

We include documentation for our updated demand and energy forecasts and generic resource costs as Attachment O to this filing.

B. EnCompass Analysis of Portfolio

Once the baseline capacity expansion plan was created – including assumed capacity purchases in any years where the reserve margin is not otherwise met – a PVRR and PVSC production cost run was performed in order to have a basis of comparison for the projects in order to evaluate both with and without the consideration of the future regulatory costs of carbon. We conducted a baseline run using both the 2023v2 IRP load forecast and the latest load forecast (2025v2), including scenarios with and without production tax credits (PTC) to evaluate the resulting planning impacts.

For the portfolio evaluation, the selected portfolio of projects was forced into the model and then the model was allowed to select capacity purchases before 2030. Short-term capacity purchases were not necessary to meet capacity needs in the portfolio evaluation and, therefore, were not selected. This portfolio model run provides a capacity expansion plan – including the selected projects – that can then be processed through production cost modeling to produce PVSC and PVRR results. This PVSC and PVRR is then compared against the baseline PVRR and PVSC described above to identify the total benefits or costs of the portfolio to our system, relative to the alternative where we procure short-term capacity purchases to meet the need before 2030 and build additional generic resources after 2030. Additional sensitivities were also performed to examine the impacts of various fuel prices, externality costs, and CO_2 regulatory costs.

Comparison of the portfolio to the base capacity plan is necessary to evaluate the impacts of the proposed portfolio. However, the baseline capacity plan forgoes the acquisition of the portfolio resources and relies on short-term market purchases when necessary to meet capacity needs before 2030. The plan developed in our last resource plan and approved by the Commission did not rely on short-term capacity purchases and limited our exposure to the wholesale energy market. Procuring sufficient resources to meet our customers' needs without reliance on market purchases is both consistent with our approved IRP and in the best interests of our customers. Therefore, while a comparison of the proposed portfolio to a base capacity plan that does not include the portfolio resources provides helpful context on the cost impacts of the proposed portfolio, we do not believe that foregoing the acquisition of the proposed resources is a reasonable alternative. Importantly, the proposed portfolio is consistent with our approved IRP, and as shown below, results in reasonable cost impacts despite the significant challenges in the current market.

The results of the EnCompass analysis show reasonable impacts to customers over the planning period, on a PVSC and PVRR basis. Table 24 below summarizes the modeled PVSC and PVRR impacts resulting from the portfolio (i.e., both projects together).

The analyses show that – on a PVSC basis – the full portfolio results in reasonable cost impacts through the 2040 planning period when generic renewable additions are assumed to receive PTCs through 2030. As shown in Table 10, we conducted analysis using the load forecast relied on in the approved IRP, as well as an updated load forecast. We also performed model runs that removed the PTCs on new generic renewable additions to reflect the current uncertainty of obtaining tax credits. Under the "No PTC" assumption the portfolio results in net benefits through 2040 when the updated load forecast is included. Cost impacts are higher through 2050 and on a PVRR basis. The increased costs in the 2040-2050 timeframe are driven by the differences in expansion plans and are much more uncertain than the nearer-term impacts.

As shown in Table 24, below, we modeled several sensitivities to assess impacts of changes in fuel prices and a range of externality and regulatory costs. The modeling shows the portfolio is expected to provide net benefits under sensitivities that include higher fuel prices and higher externality and regulatory costs. More importantly, the proposed portfolio provides a path to execute on our resource plan and procure resources despite the significant challenges in the market. By procuring the proposed portfolio, we mitigate the risks of acquiring insufficient capacity and energy and the potential need to procure higher priced resources in the future.

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Table 24
PVSC and PVRR Resulting from the Selected Portfolio ($2024 millions)

PVSC	Delta from Updated Base in NPV 2024-2040 Cost/(Savings) (millions)	Delta from Updated Base in NPV 2024-2050 Cost/(Savings) (millions)
Current Load Forecast (2025v2)	$77	$321
Current Load Forecast (2025v2) – No PTC	($70)	$110
IRP Load Forecast (2023v2)	$170	$242
IRP Load Forecast (2023v2) – No PTC	($25)	($41)
Sensitivities – Current Load Forecast (2025v2)		
High Fuel Price	($16)	$237
High Fuel Price – No PTC	($160)	$28
Low Fuel Price	$153	$383
Low Fuel Price – No PTC	$125	$458
High Externality and Regulatory Costs	($204)	$243
High Externality and Regulatory Costs – No PTC	($345)	$36
Low Externality and Regulatory Costs	$154	$493
Low Externality and Regulatory Costs – No PTC	$10	$279
PVRR	**Delta from Updated Base in NPV 2024-2040 Cost/(Savings) (millions)**	**Delta from Updated Base in NPV 2024-2050 Cost/(Savings) (millions)**
Current Load Forecast (2025v2)	$293	$537
Current Load Forecast (2025v2) – No PTC	$147	$325
IRP Load Forecast (2023v2)	$249	$349
IRP Load Forecast (2023v2) – No PTC	$57	$70

Despite the increased resource costs since we developed our resource plan, the need for additional resources in the near-term has increased. The Company provided a summary of the five-year action plan approved in our last IRP, the resources targeted in RFPs, and the remaining need in our recent filing for Proposed Generator Projects for Expedited Resource Addition Study (ERAS Request).[64]

[64] Proposed Generator Projects For Expedited Resource Addition Study (ERAS), MPUC Docket No. E002/RP-24-67 (August 4, 2025).

The updated modeling performed to analyze the proposed portfolio provides an updated assessment of our resource needs in the term-term. Based on the updated analysis, our needs for resources have increased as discussed further below.

Our updated Five-Year Action Plan shown below relies on the portfolio case, with all resources in proposed portfolio included, using the updated, current load forecast. As discussed above, the firm dispatchable resources are included in all model runs. As noted above, we removed 1,600 MW of generic resources through 2030 to create a capacity void that the proposed portfolio of 1,624 MWs is selected fill. We then locked in the remaining 1,860 MW of resources included in our model through 2029 and allowed additional resources to be selected in 2030. The 1,860 MW locked-in generics are intended to represent a minimal proxy of resources to be acquired through the Development Transfer RFP and potential ERAS projects through 2029. We expect to submit a filing to the Commission for approval of resources in each of those acquisitions in the coming months and note that the total amount of resources we bring forward may differ from the amount included as a proxy in this modeling. We allowed the model to select additional resources in 2030 to test whether additional resources would be added with the updated assumptions and as a practical limitation on the timing of new resources beyond those contemplated in existing resource acquisition process.

A summary of the additional resources based on the IRP and the updated modeling using the updated forecast is shown below:

Table 25
Updated Five-Year Action Plan

	Approved Five-Year Action Plan (MWs)	Proposed Portfolio, Dev Transfer and ERAS Project Included in Analysis
Standalone Storage	600	916
Wind	3,200	1,800
Solar	400	768
Total	4,200	3,484
Remaining Wind/Solar/Storage Need Based on IRP		716
Updated Remaining Wind/Solar/Storage Need		3,500

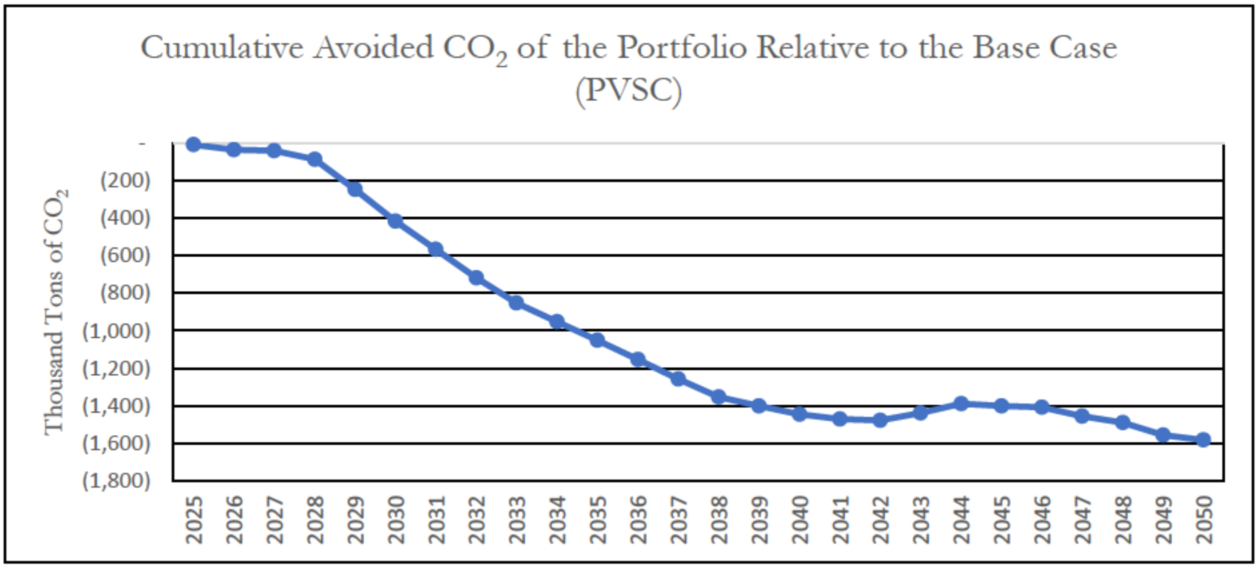
In the portfolio scenario using the updated load forecast, 1,800 MW of incremental wind resources and 1,700 MW of incremental solar resources for a total of 3,500 MW are added in 2030. This increase relative to the IRP is driven by our assumption that the PTC is not available after 2030, as well as our updated load forecast. We believe there are two important conclusions to draw from this result:

- First, the increased resource pricing has not reduced the amount of renewable resources needed and approved in our Five-Year Action Plan, and
- Second, to the extent possible, procurement of additional renewable resources in the near-term is in the interest of our customers. As discussed further below, we believe a near-term RFP for renewable resources could allow us to take advantage of any reasonably priced resources available in the next few years.

Further, across the full modeling period, the PVSC results reflect that procuring the portfolio of projects proposed in this petition avoids carbon emissions relative to the baseline. This demonstrates that in the baseline, the model is running carbon-emitting units and purchasing more energy from the market across the analysis period than in the case where the projects are procured and used to meet our customers' energy needs.

Relative to the Base Case, the selected portfolio would be expected to avoid a cumulative 1.58 million tons of CO_2 emissions over the modeling period, as shown in Figure 13 below.

Figure 13
Cumulative Avoided CO_2 of the Portfolio Relative to the Base Case (PVSC)



C. Estimated Customer Bill Impacts of Selected Portfolio

Below we provide an updated rate impact analysis using the same methodology as we used to support our IRP and Settlement Agreement, but that relies on the updated modeling performed for the project portfolio we propose in this petition.

As we discussed in the IRP, producing a detailed analysis of rate impacts in a resource planning process with long time horizons is challenging due to the potential changes in our rates and resource needs over time. Factors that can impact the estimated rate impacts in the planning period include generation ownership structure, tax treatment, regulatory decisions, large customer load additions, changes in customer class allocations, and others. The simplifying assumptions made in both the calculation methodology and the input variables mean that these estimated impacts may not align with the actual rates set by the Commission for various customer classes in the future. We caution that this information should not be interpreted as directly comparable to the customer rate impact information we would provide as part of a rate case filing.

Our customer cost impact analysis shows that the proposed portfolio results in a reasonable impact to customer costs. The proposed portfolio results in an estimated average annual increase in retail rates of 2.0 percent across our system, compared to the base case results of 1.9 percent and the Energy Information Administration (EIA) forecasted national average electricity rate increase of 2.4 percent. In other words, we can continue to add resources and achieve significant CO_2 emissions reductions with cost impacts that are less than the expected national average increase in electricity prices.

We begin by showing our Reference Case and Preferred Plan's average nominal cost as compared to the national average as forecasted by the EIA. To show the cost impact of our proposal over the long-term, we provide a compound average growth rate (CAGR) comparison of our proposed portfolio compared to the national average nominal cost CAGR for the NSP System in Figure 14, and Minnesota in Figure 15, below. As can be seen in these figures, our proposed portfolio remains lower than the national average.

Figure 14
Average Nominal Rate Increase (2025-2040)
NSP System

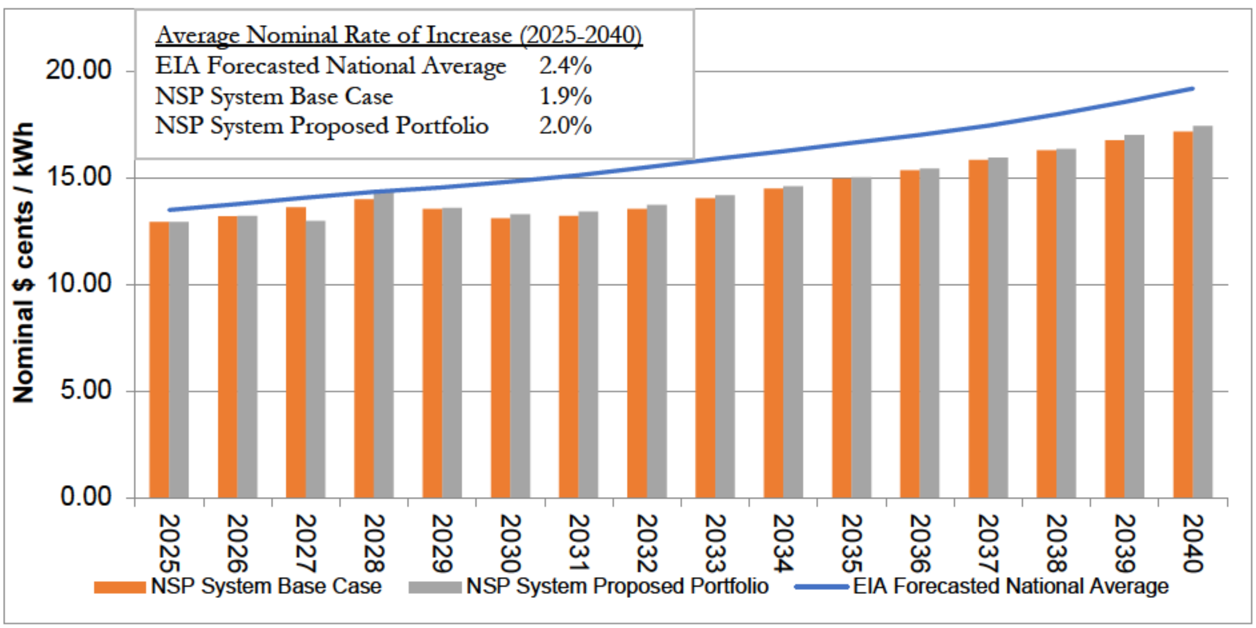
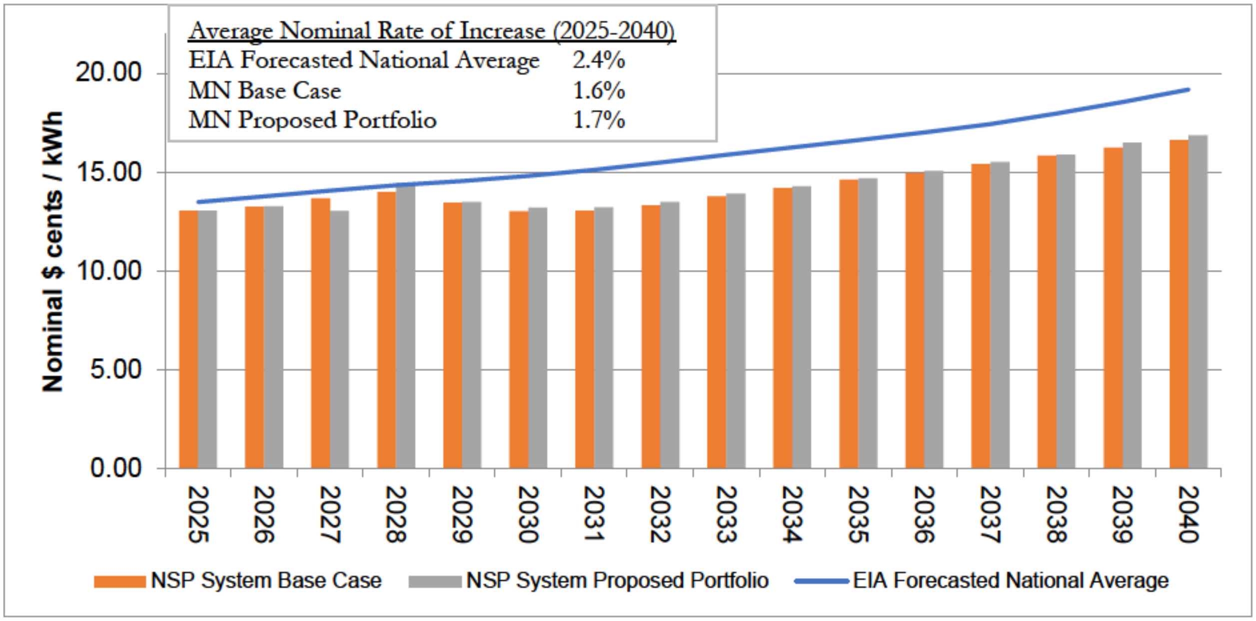


Figure 15
Average Nominal Rate Increase (2025-2040)
State of Minnesota



The results in Figures 14 and 15 also show that the Minnesota CAGR is lower than the NSP System average CAGR for the time period of 2025 through 2040. This is due to the way each CAGR is calculated. The annual NSP System average rates are calculated as the annual revenue requirement for the entire NSP System, divided by NSP System sales. The annual Minnesota rates are calculated the same way using the jurisdictional revenue requirement and the jurisdictional annual sales forecast. Since Minnesota sales are forecasted to grow more quickly than the NSP System average, they make-up a larger portion of the total NSP System sales mix in 2040 than they do in 2025. Therefore, the average rates in 2040 (and thereby the CAGR to reach those rates) for Minnesota are lower than for the NSP System as a whole.

The annual revenue requirements for the proposed portfolio and base case were jurisdictionalized using allocators from the Company's most recently-concluded, 2022-2024 Minnesota Electric Rate Case (Docket No. E002/GR-21-630. Table 26 below provides the estimated impact of the proposed portfolio for Minnesota.

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Table 26
Estimated Incremental Impact of Proposed Portfolio
State of Minnesota – All Customers

Year	Base Case Revenue Req ($000)	Incremental Impact of Resource Acquisition ($000)	Total Revenue Req ($000)	Incremental Impact (%)
2027	$4,006,224	-$190,149	$3,816,075	-4.75%
2028	$4,175,726	$136,347	$4,312,073	3.27%
2029	$4,352,400	$13,529	$4,365,929	0.31%
2030	$4,536,548	$67,600	$4,604,149	1.49%
2031	$4,728,489	$67,946	$4,796,435	1.44%
2032	$4,928,550	$67,055	$4,995,604	1.36%
2033	$5,137,075	$53,399	$5,190,474	1.04%
2034	$5,354,423	$38,239	$5,392,662	0.71%
2035	$5,580,967	$29,147	$5,610,114	0.52%
2036	$5,817,096	$36,520	$5,853,616	0.63%
2037	$6,063,216	$45,384	$6,108,600	0.75%
2038	$6,319,749	$19,948	$6,339,697	0.32%
2039	$6,587,136	$103,679	$6,690,815	1.57%
2040	$6,865,836	$103,701	$6,969,537	1.51%

The lower cost of the proposed portfolio in 2027 is due to the Investment Tax Credits associated with owned projects. The increased costs in 2028 reflect the costs of the added resources in the proposed portfolio. After 2028, costs are similar between the proposed portfolio and base scenario as the proposed portfolio offsets future resource additions that would otherwise be added.

These modest and reasonable rate impacts further support approval of the proposed portfolio.

XII. NEAR-TERM RESOURCE PROCUREMENT

As discussed above, our modeling analysis shows a need for additional resources in the near-term. As a result, the Company plans to issue an RFP in the coming months for wind, solar, storage, and hybrid resources. This timing is important to provide an opportunity to secure projects that qualify for expiring federal tax incentives and to meet anticipated load growth. By acting promptly, the Company can leverage this time-sensitive opportunity to capture customer cost benefits while advancing resource adequacy and supporting long-term system needs.

XIII. REGULATORY PROCESS AND RIDER RECOVERY

In this section, we provide an overview of approvals and processes required in our other jurisdictions. We also explain why cost recovery through the Renewable Energy Standard (RES) Rider is appropriate for the Company's self-build projects, and why the Fuel Clause Rider is suitable for the PPAs.

A. Jurisdictional Allocation and Procedure Required in Wisconsin and North Dakota

Our integrated Upper Midwest System provides service on a multi-jurisdictional basis to 1.8 million customers across five states. Through this integration, we have historically leveraged economies of scale to support needed investments. Each resource on the Upper Midwest System – whether generation or transmission – was developed in consideration of the whole system, to take advantage of the economies of scale available through integrated system planning. While integrated planning provides benefits across our system, we have faced challenges recovering the costs of certain resources across the jurisdictions we serve. We currently do not fully recover the costs of our solar resources or our Community-Based Energy Development (C-BED) PPAs.

We note that we filed our first North Dakota IRP on April 8, 2024. In our 2024-2040 North Dakota IRP, we conducted a high wind and solar resource cost sensitivity analysis that more closely aligns with the pricing reflected in this RFP. Compared to the North Dakota Preferred Plan, this sensitivity results in significantly lower renewable resource additions over the planning period. While our ND Preferred Plan includes wind resource additions similar to the Upper Midwest Preferred Plan, the ND Preferred Plan did not include solar additions – and the significant wind additions in the North Dakota Preferred Plan are contingent on the ability to procure those resources at costs consistent with our base assumptions. If wind resource costs are higher, fewer additions will be cost-effective, likely leading to greater divergence between the North Dakota and Upper Midwest Preferred Plans.[65] Moreover, as noted above, in order to comply with Minnesota's 100x40 CFS law, it was necessary to impose a constraint in the Encompass modeling, meaning that Minnesota law directly impacts the updated expansion plan. Accordingly, the Company is evaluating a jurisdictional allocation approach similar to that advanced by Otter Tail Power it its recent resource acquisition proceeding (OTP proceeding).[66] We request that the Commission allow the Company to propose any changes to our jurisdictional allocation approach in a future RES Rider filing for resources that we are not able to obtain approval of in another jurisdiction.

The cost allocation the Commission approved in the OTP proceeding is designed to allocate the benefits of the project to the jurisdictions incurring the costs. If the resource preferences of the jurisdictions we serve continue to diverge, a similar cost allocation could allow each jurisdiction to advance their planning preferences while maintaining the benefits of the integrated system. We would seek a determination from the North Dakota Public Service Commission and South Dakota Public Utilities Commission prior to requesting a change in the jurisdictional allocation of costs associated with the resources requested in this Petition.

Finally, since the One Energy solar projects are located in Wisconsin, Xcel Energy's Wisconsin Operating Company, NSPW, is the party to the One Energy projects. NSPW will seek any necessary project approvals from the Public Service Commission of Wisconsin. The cost of resources in NSPW, such as One Energy solar, are shared across our Upper Midwest System through the Interchange Agreement.

B. Sherco Solar 4, Blue Lake BESS, and Sherco South BESS are Eligible for Recovery through the RES Rider

1. *Sherco Solar 4*

The Sherco Solar 4 project qualifies for recovery through the RES Rider pursuant to Minn. Stat. § 216B.1645 subd. 2a. As shown below, in addition to RECs generated by the portfolio of solar PPA projects in Table 1, RECs from the Sherco Solar 4 facility will represent another important step toward meeting Minnesota's Eligible Energy

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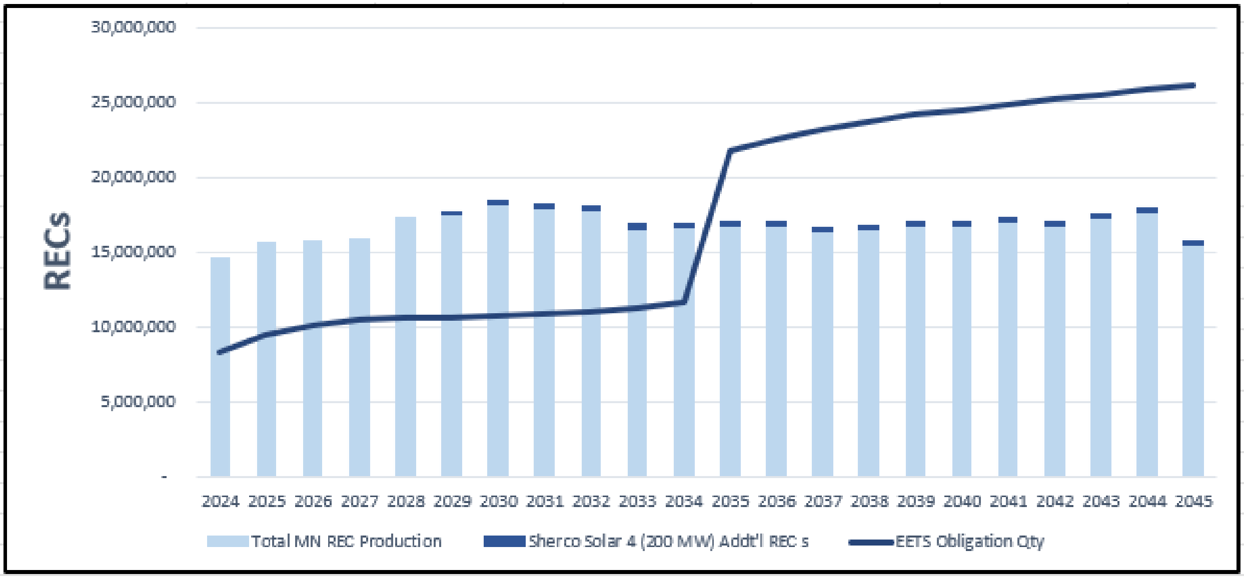
[65] Xcel Energy 2024-2040 North Dakota Resource Plan, NDPSC Docket No. PU-160 (April 8, 2024) at Chapter 5 at pp. 26 and 33. Our North Dakota Resource Plant was also filed in MPUC Docket No. E002/24-163.

[66] Docket No. E017/M-24-404.

Technology Standard (EETS)[67] under Minn. Stat. § 216B.1691 subd. 2a, which requires that 55 percent electricity be generated by an eligible energy technology by 2035.[68]

Figure 16
EETS Compliance with Sherco Solar 4 Additions



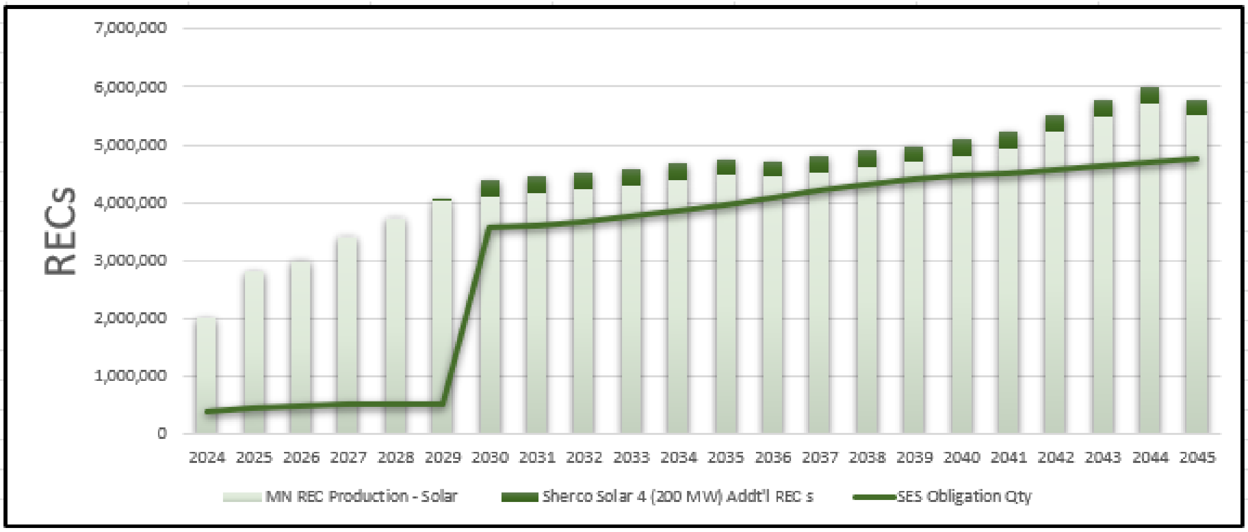
As demonstrated in Figure 16 above, even when assuming that the PPAs for Fillmore, Grant, Gopher State and Lemon Hill Solar (494 MW) projects will be approved, there still remains an evident need for renewable energy resources to meet EETS compliance requirements beginning in 2035 (notwithstanding other future planned renewable additions). The Company estimates satisfying EETS compliance requirements through year 2034 under the current 30 percent RES requirements. The addition of the Sherco Solar 4 project in 2029 to the total Minnesota Renewable Energy Credit (REC) accumulated inventory will incrementally support the Company's progress towards achieving the annual EETS compliance requirement beginning in 2035 when the EETS increases to 55 percent.

Further, Sherco Solar 4 will contribute to the Solar Energy Standard (SES) in Minn. Stat. § 216B.1691 subd. 2f, which requires 1.5 percent of retail sales in Minnesota to be generated by solar energy, with a goal of ten percent by 2030. The Company's

[67] Formally known as the Renewable Energy Standard (RES).
[68] Eligible energy technology is defined in Minn. Stat. § 216B.1691, Subd. 1(c).

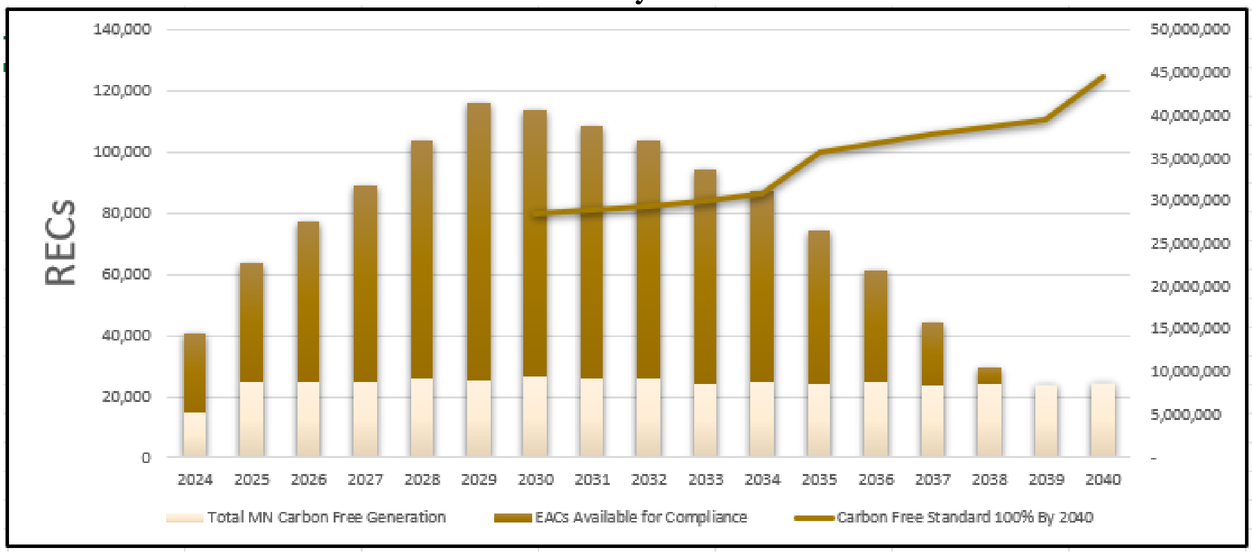
projected compliance with Minnesota's SES is shown in Figure 17 below. The Company can demonstrate the ability to meet the 10 percent goal SES from 2030 through 2045. The additional RECs from Sherco Solar 4 could also be applied toward compliance with EETS or CFS.

Figure 17
Minnesota SES Compliance Position
Solar Resources Including Sherco Solar 4 (2029)
10% Solar Goal – 2030



Finally, as shown in Figure 18 below, Sherco Solar 4 will contribute to the CFS in Minn. Stat. § 216B.1691 subd. 2g, which requires 80 percent of retail sales in Minnesota to be generated by carbon-free energy technologies by 2030.

Figure 18
Minnesota CFS Compliance Position
Including Sherco Solar 4 Addition and Banked EACs
100% by 2040



Because Sherco Solar 4 is necessary for the Company to achieve compliance with Minnesota's Renewable Energy Objectives outlined in Minn. Stat. § 216B.1691 as discussed above, it is reasonable and appropriate to recover Minnesota's project costs through the RES rider.

2. Blue Lake BESS and Sherco South BESS

The Company respectfully requests Commission approval to recover costs associated with the Blue Lake and Sherco South BESS projects through the RES Rider, pursuant to Minn. Stat. § 216B.1645.

Section (3) of Minn. Stat. § 216B.1645 allows recovery of other expenses incurred that are directly related to a renewable energy project, including expenses for energy storage, provided that the utility demonstrates to the Commission's satisfaction that the expenses improve project economics, ensure project implementation, advance research and understanding of how storage devices may improve renewable energy projects, or facilitate coordination with the development of transmission necessary to transport energy produced by the project to market.

While the Blue Lake BESS and Sherco South BESS will be charged from the grid, they are designed to support the integration, reliability, and optimization of renewable energy resources across the Company's system. The projects align with the statutory intent and Commission precedent for cost recovery under the RES Rider and will contribute to the Company's – and the State's – broader strategy of enabling higher renewable penetration and grid decarbonization.

Battery storage systems such as the Blue Lake BESS and Sherco South BESS advance research and understanding of how storage devices may improve renewable energy projects, as intended by the statute. The projects allow for storage of excess electricity generated by other power producers during periods of low electricity demand, with the ability to send the electricity back to the grid when demand increases. Beyond supporting the goals of the IRP, the projects aim to support Minnesota's transition to a carbon-free electricity supply by enabling wind and solar projects to continue generating clean energy instead of being curtailed due to low demand. By charging an ESS, it can store excess energy during these periods and discharge it during times of higher demand, such as daytime or evening hours, helping to supplement existing generation and potentially reducing reliance on traditional thermal sources like natural gas.

The impact to the grid from the integration of BESSs will advance research and understanding of how storage devices may improve renewable energy projects, including:

- **Supports integration of renewable energy:** The integration of BESS enables higher and more efficient use of existing and new renewable energy sources.
- **Frequency response and regulation:** Strong BESS infrastructure provides moment-to-moment stability for the electrical system more efficiently than existing natural gas resources.
- **Reduce energy waste:** BESS stores energy when there is an excess supply and discharges that energy back onto the grid when supply is low.
- **Grid Resiliency:** BESS can support recovery from storms and other grid emergencies by more efficiently using the operating portions of the grid and providing the grid operator and utility additional flexibility while they work to restore the system.

The projects align with the statutory intent for cost recovery under the RES Rider. The projects are designed to advance research and support the integration, reliability, and optimization of renewable energy resources across the Company's system. They will store excess energy during periods of surplus and release it during peak demand, helping offset the need for additional peak-generation capacity, while also supporting renewable integration, grid stability, and operational efficiency. We therefore request recovery of the Blue Lake BESS and Sherco South BESS project through the RES Rider.

C. PPA Projects are Eligible for Recovery through the Fuel Clause Rider

Pursuant to Minn. Stat. § 216B.16 subd. 7(3), the costs for "fuel used in generation of electricity" are eligible for automatic adjustment under the Fuel Clause Rider. Under the terms of our currently effective Fuel Clause Rider in our tariff, "[t]he energy cost of purchases from a qualifying facility" are "qualifying costs" that comprise the Cost of Energy. Because the projects satisfy the conditions of a qualifying facility (QF), the Company plans to recover the costs of these PPAs through our Fuel Clause Rider. No net increase in revenue to Xcel Energy will result from these transactions, as the power purchases will equal the revenue collected.

CONCLUSION

In this filing, we have discussed a portfolio of solar and storage projects that are in the public interest. The projects represent the first new resources proposed as we implement our approved Resource Plan, and they were selected using a fair and transparent Commission-approved bidding process. The portfolio of projects we present for Commission approval in this Petition will:

- Provide the needed capacity and energy to meet system needs to serve our customers;
- Reduce carbon emissions;
- Capture a time-sensitive opportunity to leverage federal tax credits;
- Enable renewable integration and improve grid reliability by storing excess energy during periods of surplus and releasing it during peak demand, helping to offset the need for additional peak-generation capacity;
- Provide cost-effective energy storage that supports system operations, enhances power quality, and delivers ancillary services to the regional grid;
- Create local, union jobs and generate local economic benefits; and

- Expand renewable energy in Minnesota and the region, helping the Company meet its obligations under Minnesota's expanded Renewable Energy Standard and "100 percent by 2040" Clean Energy Standard.

Specifically, we request that the Commission take the following actions:

- Find that the Company's proposed solar and standalone storage portfolio is in the public interest;
- Approve the Power Purchase Agreements (PPAs) provided with this filing;
- Approve the acquisition and construction of the Company's self-build projects – Blue Lake BESS, Sherco South BESS, Sherco Solar 4 – and the Company's proposed approach of recovery for these project costs for the Minnesota jurisdiction through the Renewable Energy Standard (RES) Rider;
- Approve the Company's acquisition of land rights for the Sherco Solar 4 project;
- Approve the Company's request for a variance of the requirements of Minn. R. 7825.1800, subp. B;
- Authorize the Company to propose any changes to our jurisdictional allocation approach in a future RES Rider filing for resources that we are not able to obtain approval of in another jurisdiction;
- Authorize the Company to recover, through the Fuel Clause Rider, pursuant to Minn. Stat. § 216B.16 subd. 7(3), the Minnesota jurisdictional portion of the costs incurred under the PPAs from Minnesota retail customers; and
- Establish a procedural schedule such that the Commission may complete deliberations by mid-February 2026. Earlier approval increases the likelihood that projects will qualify for the expiring tax incentives and reduces the risk of construction delays or project failures.

Dated: October 31, 2025

Northern States Power Company

PUBLIC DOCUMENT
NOT-PUBLIC DATA HAS BEEN EXCISED

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben	Chair
Hwikwon Ham	Commissioner
Audrey C. Partridge	Commissioner
Joseph K. Sullivan	Commissioner
John A. Tuma	Commissioner

IN THE MATTER OF XCEL ENERGY'S 2024 WIND, SOLAR, STORAGE, AND HYBRID REQUEST FOR PROPOSALS

DOCKET NO. E002/M-24-230

PETITION

SUMMARY OF FILING

Please take notice that on October 31, 2025, Northern States Power Company doing business as Xcel Energy filed with the Minnesota Public Utilities Commission a Petition requesting approval of a portfolio of solar and storage projects selected in our 2024 Request for Proposal.

Xcel Energy

2024 Wind, Solar and Storage RFP

Closing Report of Guidehouse, Inc. as Independent Auditor

Prepared for:

Xcel Energy

Submitted by:

Ralph Luciani, Director
Guidehouse Inc.

guidehouse.com

August 1, 2025

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Executive Summary

Background

This report summarizes the assessments and findings of Guidehouse Inc. as the independent auditor ("IA") for the 2024 Wind, Solar and Storage Requests for Proposals (the "RFPs") as performed by Northern States Power Company, doing business as Xcel Energy (the "Company"). The purpose of the RFPs was to solicit proposals for the Company to fill a need for capacity and energy as identified in the Company's 2020-2034 and 2024-2040 Upper Midwest Integrated Resource Plans (IRPs). Two separate RFPs were issued, one by Northern States Power Company-Minnesota ("NSPM RFP") on June 28, 2024, and one by Northern States Power Company-Wisconsin ("NSPW RFP") on July 1, 2024 (collectively, "RFPs"). The Company retained Guidehouse as the IA to independently audit the RFP process, using its prior experience with utilities across the U.S. with similar procurements for wind, solar and storage resources.[1]

The RFPs collectively sought 1,600 MW of solar, wind or storage resources with a commercial operating date (COD) by December 31, 2029. The NSPM RFP sought resources located in Minnesota, North Dakota, or South Dakota in MISO Zone 1 or on the NSPM distribution system. The NSPW RFP sought resources located in Michigan or Wisconsin in MISO Zone 1 or on the NSPW distribution system. The 1,600 MW sought could be supplied through either the NSPM RFP or the NSPW RFP, and all submitted bids were analyzed and scored together. The NSPM RFP allowed for Purchase Power Agreement ("PPAs"), Build Transfers ("BTs"), and self-build projects, while the NSPW RFP allowed only BTs.

To comply with MISO requirements regarding reuse of the interconnection rights for the retiring Sherco and Blue Lake generation stations, the NSPM RFP allowed only company-owned (BT and self-build) bids proposing the reuse of these interconnection rights. Given uncertainty with respect to the final routing of the Minnesota Energy Connection (MNEC) Project, those NSPM RFP bids proposing interconnection to the MNEC Project were permitted to bid on a contingent basis dependent on the final routing of the MNEC Project ("Contingent Bids").[2] Of the 1,600 MW sought in the RFPs, up to 800 MW of Contingent Bids could be shortlisted for additional study, and ultimately selected as shortlisted bids once the MNEC Project routing was finalized and final bid costs could be assessed. Contingent Bids were analyzed and scored together with all other RFP bids ("Traditional Bids").

In addition to the 1,600 MW of NSP capacity and energy needs sought in the RFPs, the NSPW RFP separately sought an additional 650 MW of solar or storage resources physically located in Wisconsin with proximity to the King Gen-Tie. These bids would reuse interconnection rights for the retiring Allen S. King Generating Station.

The NSPM RFP follows a Modified Track 2 process as approved by the Minnesota Public Utilities Commission ("MPUC") when the Company may choose to submit a self-build bid. In a MPUC Modified Track 2 process, the RFP is open to bids developed by the Company itself

[1] Guidehouse has led or assisted utilities with the procurement of more than 9 gigawatt of renewable and storage resources in the U.S. and has served as the IA or equivalent for utility procurement of renewable and storage resources in many states, including Connecticut, Massachusetts, Michigan, Minnesota, New Mexico, Ohio and Texas.

[2] The MNEC Project is a proposed new double-circuit 345-kilovolt (kV) transmission line between the retiring Sherco coal plant near Becker, MN, and Lyon County in southwest MN.

("self-build") and 3rd party bids under a procurement process monitored by an IA. Given the potential for Company self-build bids, under the oversight of the IA, an internal firewall between the Company staff who may work on self-build bids and Company staff on the RFP evaluation team was established for the RFPs in May 2024.

Bid Submittals and Evaluations

Bids in the NSPM RFP and NSPW RFP were due on September 18, 2024, with any NSPM RFP self-build bids due one day earlier.[3] A total of 41 bids were received, for 30 distinct projects totaling approximately 1,475 MW of solar, 410 MW of wind, 1,340 MW of standalone storage, and 1,180 MW of solar plus storage.[4] Of the 30 distinct projects, 20 were physically located in Minnesota, 3 in South Dakota, and 6 in Wisconsin.[5] There were three self-build bids submitted in the NSPM RFP. In accordance with the MPUC Modified Track 2 procedures, details regarding the Company's self-build bids were filed in MPUC Docket No. E002/M-24-230 on September 25, 2024. Of the 38 third-party bids submitted, 21 were PPAs and 17 were BTs.

Starting in September 2024, three evaluation stages were performed on the submitted bids as monitored and examined by the IA: 1) Completeness, 2) Threshold, and 3) Scoring and EnCompass Selection. During the RFP evaluation process, **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** bids were withdrawn by the bidders and **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** bids did not pass the RFP threshold evaluation as they did not meet the evaluation criteria outlined in the RFP.[6] In addition, **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** bid technical variations were excluded from further consideration as less favorable than alternative bids for the same project. The remaining **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** bids that reached the scoring stage comprised **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** distinct projects and approximately **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** of distinct capacity.

In accordance with the RFP evaluation process, a series of analytic steps were applied to these remaining bids to select the shortlisted bids. The analytical steps included bid scoring, an EnCompass selection analysis and a cost-effectiveness screen.[7] The EnCompass analysis was performed using an updated Upper Midwest load forecast with significantly more peak demand by 2030 than the original IRP load forecast used to create the 1,600 MW RFP target.[8] With the updated forecast, the EnCompass analysis showed that a larger amount of renewable and storage capacity could be economically selected than the original 1,600 MW target.

With the approval of the IA, approximately **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** of Traditional Bids were selected for the shortlist and were notified on January 10, 2025. In total, **[PROTECTED DATA BEGINS PROTECTED DATA**

[3] In addition to the internal firewall, requiring self-build bids to be submitted one-day earlier than third-party bids helps further ensure that Company self-build bids are submitted without knowledge of third-party bids and prices.

[4] No wind plus storage bids were submitted. The listed solar plus storage capacity includes the capacity for two project sites that were separately bid as solar only.

[5] One bid was submitted for a project located in a state not eligible under the RFP requirements.

[6] Of the 11 bids that did not pass the Threshold review, the main reasons included not meeting the site control, location, interconnection, and technology threshold criteria. Throughout the Threshold review process, all bidders were given ample opportunity to address or cure deficiencies identified by the Company evaluation team. The IA monitored and reviewed the Threshold review forms for each proposal and agreed with Company findings.

[7] EnCompass is a power market simulation model used by the Company in its IRP modeling.

[8] Load Forecast 2024H2

ENDS] Traditional Bids were selected for the shortlist, representing **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** distinct projects from **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** distinct bidders. Of the **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**, approximately 435 MW was self-build capacity, **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** were PPAs, and **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** were BTs. Approximately, **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** was solar capacity and **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** was standalone storage capacity. No wind resources or solar plus storage resources were selected for the shortlist.

Of the **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** shortlisted Traditional Bids, **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** were submitted in the NSPM RFP. These bids comprised approximately **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** of solar capacity and **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** of standalone storage, as follows:

- Two self-build standalone storage projects, a 136 MW project, which reuses Blue Lake interconnection rights and a 300 MW project which reuses Sherco interconnection rights.

- **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** standalone storage PPAs from **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** different bidders, comprising approximately **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**, and **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** solar PPAs from **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** different bidders, comprising approximately **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**.

- **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** of the **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** bids selected were for projects located in South Dakota, and**[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** were for projects located in Minnesota. All **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** bids were transmission interconnected.

[PROTECTED DATA BEGINS PROTECTED DATA ENDS] shortlisted Traditional Bids were submitted in the NSPW RFP. Each was a BT, physically located in Wisconsin, and interconnected to the NSPW distribution system. Collectively, the two bids represented approximately **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** of solar capacity.[9]

In addition, **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** Contingent Bids in the NSPM RFP were shortlisted for further evaluation in January 2025, representing **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** distinct projects from **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** different bidders and approximately **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** of solar capacity. Of the **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**, 200 MW was self-build capacity and the remainder were BTs. These projects were shortlisted for further study and evaluation once the MNEC Project routing was approved by the MPUC.

[9] No bids were received in the NSPW RFP proposing interconnection to the King Gen-Tie.

After the MPUC's verbal approval of the MNEC Certificate of Need and Route Permit on April 10, 2025, each of the **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** Contingent bidders were required to submit updated project costs, based on the approved route. **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** The remaining updated Contingent Bid, a 200 MW self-build solar facility, was selected as a final shortlisted bid on June 24, 2025.

In sum, with the review and approval of the IA, **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** distinct projects from **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** different bidders were selected for the final shortlist comprising **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** of solar capacity and **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** of standalone storage capacity. Overall, this yielded a total of approximately 2,120 MW of Traditional and Contingent Bids selected for the final short list. Relative to the 1,600 MW initially sought in the RFP, this overall total of 2,120 MW is consistent with the increase by 2030 in NSP capacity and energy needs in the latest load forecast, and hedges against the potential for some shortlisted projects to not reach the final contracting stage.

IA Process

The IA worked closely with the Company's RFP evaluation team throughout the RFP development process to ensure that the RFP was clear and transparent, the requested bidder submittal items were aligned with the scoring criteria, and all items necessary for evaluation were requested in the RFP. The IA reviewed the entire set of proposed RFP materials and provided comments and suggestions based on experience with similar RFPs. The Company incorporated these suggestions in the final RFPs to the satisfaction of the IA. Prior to bids being received, the IA and the Company worked together to create an RFP Evaluation Guide and associated scoring sheets to be used to evaluate each proposal consistent with the evaluation process and criteria described in the RFP.

The IA had full access to the Company RFP evaluation team files throughout the RFP process, including all evaluation and scoring files. The IA was copied on emails to and from the RFP mailbox and reviewed all responses to bidder questions prior to posting on the RFP websites. The IA and the RFP evaluation team leads met regularly (usually weekly) throughout the RFP process to discuss any pending issues and concerns. The IA worked closely with the Company to set up and monitor the internal firewall. The IA reviewed the results of the Completeness and Threshold reviews for each bid, asked clarifying questions of the RFP evaluation team, and independently agreed with Company findings. The IA reviewed the scoring and EnCompass modeling process for the remaining bids and approved the selection of the final shortlist. Throughout the process, the IA had full access to the information needed to ensure that the RFP would be conducted in a fair and transparent manner.

Summary of Findings

Guidehouse has completed its assessment of the RFPs and finds the following:

- The Guidehouse overall assessment is that the RFPs were conducted on a fair and consistent basis, with over **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** of solar energy and standalone storage projects selected for the final shortlist under the Traditional Bid and Contingent Bid process. This was more than the 1,600 MW originally sought in the RFPs, consistent with the increase in NSP capacity and energy needs in the latest load forecast and the potential for some shortlisted projects to not reach the final contracting stage.
- The RFP completeness and material threshold evaluations were performed for each proposal on a fair and consistent basis using the process described in the RFP. Respondents were given ample opportunity to cure deficiencies within a reasonable period. The criteria used were reasonable and consistent with similar criteria we have developed or observed.
- The RFP scoring and selection stage, including the economic and non-economic scoring and EnCompass modeling, was performed on a fair and consistent basis using the process described in the RFPs. The criteria used were reasonable, and the limitation of the shortlist to the most cost-effective bids was reasonable.
- The selection of the Contingent bids shortlisted for further study and evaluation once the final MNEC Project routing was approved by the MPUC was performed on a fair and consistent basis using the process described in the NSPM RFP. After the MNEC route approval by the MPUC, the selection of the Contingent Bids for the final shortlist was performed on a fair and consistent basis using the process described in the NSPM RFP.
- There was strong interest in the RFPs, as evidenced by the number of bids received.
- With respect to messages between the Company, interested parties, and respondents, we observed that the Company's responses were timely, consistent, and fair, indicating a high level of engagement by the Company.
- Based on the IA's review and observations, there is no evidence that the evaluation and selection process caused any unfair advantage or disadvantage to any interested party or respondent, including the Company's self-build bids.

This report summarizes Guidehouse's review and findings as of the date of this report. We relied on documents, correspondence, analyses, and other information provided to us by the Company to perform our work. While we believe this information to be reliable, it has not been independently verified for either accuracy or validity, and no assurances are offered with respect thereto. Guidehouse makes no representations, warranties, or opinions concerning the enforceability or legality of the laws, regulations, rules, agreements, or other similar documents reviewed as part of its work. Guidehouse and its employees are independent contractors providing professional services to the Company and are not officers, employees, or agents of the Company.

1. General RFP Background

Two separate RFPs were issued, one by Northern States Power Company-Minnesota ("NSPM RFP") on June 28, 2024, and one by Northern States Power Company-Wisconsin ("NSPW RFP") on July 1, 2024 (collectively, "RFPs"). The purpose of the RFPs was to solicit proposals for the Company to fill a need for capacity and energy as identified in the Company's 2020-2034 and 2024-2040 Upper Midwest IRP.[10]

The RFPs collectively sought 1,600 MW of solar, wind or storage resources with a commercial operating date (COD) by December 31, 2029. The NSPM RFP sought resources located in Minnesota, North Dakota, or South Dakota in MISO Zone 1 or on the NSPM distribution system. The NSPW RFP sought resources located in Michigan or Wisconsin in MISO Zone 1 or on the NSPW distribution system. The 1,600 MW sought could be supplied through either the NSPM RFP or NSPW RFP, and all submitted bids were analyzed and scored together.[11] The NSPM RFP allowed for PPAs, BT, and self-build projects, while the NSPW RFP allowed only BTs.

To comply with MISO requirements regarding reuse of the interconnection rights for the retiring Sherco and Blue Lake generation stations, the NSPM RFP allowed only company-owned (BT and self-build) bids proposing the reuse of these interconnection rights. Given uncertainty with respect to the final routing of the MNEC Project, those NSPM RFP bids proposing an MNEC Project interconnection were permitted to bid on a contingent basis dependent on the final MPUC-approved routing of the MNEC Project ("Contingent Bids").[12] Contingent Bids were analyzed and scored together with all other RFP bids ("Traditional Bids").

[10] The NSPM RFP follows a Modified Track 2 process as approved by the MPUC when the Company may choose to submit a self-build bid. In a MPUC Modified Track 2 process, the RFP is open to bids developed by the Company itself ("self-build") and 3rd party bids under a procurement process monitored by an IA. The Company retained Guidehouse as the IA to independently audit the RFP process, using its prior experience with utilities across the U.S. with similar procurements for wind, solar and storage resources.

[11] In addition to the 1,600 MW of NSP System needs sought in the RFPs, the NSPW RFP separately sought an additional 650 MW of solar or storage resources physically located in Wisconsin with proximity to the King Gen-Tie. These bids would reuse interconnection rights for the retiring Allen S. King Generating Station.

[12] Of the 1,600 MW sought in the RFPs, up to 800 MW of Contingent Bids could be shortlisted for additional study and ultimately selected as shortlisted bids once the MNEC Project routing was finalized and final bid costs could be assessed.

2. RFP Development and Design

2.1 Establishment of Firewall and Communication Protocols

Given the potential for self-build bids to be submitted in the NSPM RFP under the MSPC Modified Track 2 process, an internal communications protocol ("Separation Protocol" or "firewall") was established requiring that those at the Company involved in self-build proposals would have no communication related to this RFP with members of the RFP evaluation team other than through the same process available to all other potential bidders. Under the Separation Protocol, no self-build team member was permitted access to the RFP evaluation team SharePoint site containing files and materials used in the RFP evaluation process. The Separation Protocol also governed the communication process the RFP evaluation team would use to communicate with bidders, both external and internal to the Company.

RFP specialists, because of the scarcity of their expertise within the utility, were designated and authorized to provide information to both the RFP evaluation team and the self-build team. The RFP specialists could not share information about RFP-related support provided to the RFP evaluation team to members of the self-build team, and vice versa.

Under the oversight of the IA, the internal firewall between the Company self-build team and the RFP evaluation team was established in May 2024. A roster of the members of each team was created and managed by the RFP Evaluation Team Leader. Each team member signed an acknowledgement that they understood and would follow the separation protocols. Updates to the rosters were issued periodically by the RFP Evaluation Team Lead to all team members so that they could be aware of any changes to the team rosters. Any new members of the teams also signed an acknowledgement.

The IA and the RFP Evaluation Team Leads closely monitored the firewall and communication protocol throughout the RFP process. Responses to any questions that arose with respect to the protocols were discussed and approved by the IA. The IA monitored all communications with potential and actual bidders by the RFP evaluation team through the time of the final shortlist notification. In particular, the IA was copied on all communications with bidders through the RFP mailbox. As planned, the firewall with respect to the Traditional Bids was terminated upon the selection and IA approval of the Traditional Bid shortlist on January 10, 2025. The firewall continued with respect to the Contingent Bids shortlisted for additional study on January 10, 2025. The firewall with respect to the Contingent Bids was terminated upon the selection and IA approval of the Contingent Bids selected for the final shortlist on June 24, 2025.

2.2 RFP Design

This section summarizes the design of the RFPs. The IA worked closely with the Company throughout the RFP development process to ensure that the RFPs were clear and transparent, the requested submittal items were aligned with the scoring criteria, and all items necessary for evaluation were requested in the RFPs. The IA reviewed the entire set of proposed RFP materials and provided comments and suggestions based on our experience with similar RFPs. The Company incorporated these suggestions in the final RFPs to the satisfaction of the IA. Prior to bids being received, the IA and the Company worked together to create an RFP Evaluation Guide and associated scoring sheets for evaluation of each proposal consistent with the evaluation process and criteria described in the RFPs.

The IA had full access to the Company RFP evaluation team files throughout the RFP process, including all evaluation and scoring files. The IA was copied on emails to and from the RFP mailbox and reviewed all responses to bidder questions prior to posting on the RFP website. The IA and the RFP evaluation team leads met regulatory (usually weekly) throughout the RFP process to discuss any pending issues and concerns. The IA reviewed the results of the Completeness and Threshold reviews for each bid, asked questions of the RFP evaluation team, and agreed with Company findings. The IA reviewed the scoring and evaluation process for the remaining bids and approved the selection of the shortlisted bids. Throughout the process, the IA had full access to the information needed to ensure that the RFPs would be conducted in a fair and transparent manner.

2.2.1 Qualifying Bids

The RFPs were open to new wind, solar, wind-plus-storage, solar-plus-storage, and standalone storage resources. The bids had to be greater than 5 MW in size and have a COD no later than December 31, 2029.[13] Projects had to be located within MISO Zone 1, or on the NSPM distribution system (NSPM RFP), or the NSPW distribution system (NSPW RFP).[14] Projects had to be physically located in Minnesota, North Dakota or South Dakota for the NSPM RFP, and physically located in Michigan or Wisconsin for the NSPW RFP. Projects located in MISO Zone 1 with a new Point of Interconnection were required to have a generator interconnection application in the MISO 2021 Definitive Planning Process ("DPP") Cycle or an earlier MISO cycle. Projects also could propose the use of surplus or Generator Interconnection Applications at existing MISO POIs.

In the NSPM RFP, for Contingent Bid projects proposing to interconnect with the MNEC Project, a MISO interconnection application was not required at the time of bid submittal. Similarly, in the NSPW RFP, projects proposing to interconnect with the King Gen-Tie did not require a MISO interconnection application at the time of bid submittal.

2.2.2 Bid Contract Type

Both RFPs allowed bidders to submit proposals for build transfer agreements ("BTs"). Bidders were required to submit BT bids with no exceptions to the BT Purchase and Sale Term Sheets supplied in the RFP documentation. If they submitted this "standard bid", bidders also could submit an alternate priced BT bid for the same project with specific redlines to the BT term sheets.

In the NSPM RFP, PPA proposals were allowed for the MISO Zone 1 and distribution interconnected projects not reusing the Sherco or Blue Lake interconnection rights. Bidders were required to submit PPA bids with no exceptions to the Model PPAs supplied in the RFP documentation. PPA bids in the NSPM RFP could have terms between 10 and 30 years for new projects, and between 5 and 15 years for PPA extensions. A fixed price in $/MWh was required (a fixed annual escalation was permitted). Self-build bids also were permitted in the

[13] In the NSPM RFP, existing resources could also bid if they offered net new capacity greater than 1 MW to NSPM (e.g., through repowering or extension of an expiring PPA). In the NSPW RFP, newly repowered facilities also were eligible.

[14] Projects located on the NSPM distribution system were required to have a signed interconnection agreement with NSPM as of June 28, 2024. Projects located on the NSPW distribution system were required to have an Interconnection Approval Memorandum with NSPW as of July 10, 2024.

NSPM RFP and were required to adhere to the same requirements and form submittals as all other proposals.

2.2.3 Bid Fees

For both the NSPM RFP and the NSPW RFP, a $10,000 fee was required for each proposal submitted, payable to the Company, for transmission-interconnected projects. For distribution interconnected projects, a $5,000 bid fee was required. A separate bid evaluation fee was required for project proposals with different COD, interconnection choice, pricing, sites, PPA term length, equipment type, or MW size.[15]

A refundable second bid fee of $1/kW was required to begin negotiation of a Power Purchase Agreement or Purchase and Sale Agreement for short-listed bidders.

2.2.4 RFP Schedule

The NSPM RFP was issued on June 28, 2024. The NSPW RFP was issued on July 1, 2024, and an updated version was issued on July 2, 2024. A bidder conference for the NSPM RFP was held on July 24, 2024, and for the NSPW RFP on July 25, 2024. For both RFPs, an optional Notice of Intent to Respond was due on August 15, 2024, respondent questions could be submitted through September 8, 2024, and bids were due on September 18, 2024. Self-build bids in the NSPM RFP were due on September 17, 2024, one day earlier than third-party bids. At the time the RFPs were issued, the shortlisting of bids was projected to take place on December 18, 2024. Given the time necessary to ask additional cure questions and evaluate bids, bidders were notified in December 2024 that the shortlisting of Traditional Bids would take place on January 10, 2025.

2.2.5 Project Qualification and Scoring

As described in Section 5 of the RFPs ("RFP Proposal Evaluation"), the objective of the evaluation was to identify proposals that meet the resource objectives identified in the solicitation in a reliable and cost-effective manner and which are likely to be developed and placed into commercial operation. The Company applied a three-phased approach to evaluating each bid proposal: 1) Completeness review, 3) Threshold review and 3) Project Scoring and EnCompass selection.

<u>Completeness Review.</u> This review focused on whether proposals complied with all bid submittal requirements, including bid fees and submission of all required information and forms, with bidders provided an opportunity to cure any proposals with deficiencies.

<u>Threshold Review.</u> This review focused on whether proposals met the minimum threshold criteria for the bid to be considered able to meet the core RFP objectives, including COD, size, location and technical requirements, site control and permitting, firm pricing, technical feasibility, capacity accreditation requirements, and submission of a standard bid with acceptance of the standard Model PPAs or Purchase and Sale Agreement Term Sheets without exceptions. Again, an opportunity to cure was offered to bidders for any failure to meet threshold criteria.

[15] Self-build proposals in the NSPM RFP were exempted from the bid fee requirements to avoid accounting issues associated with the Company making payments to itself.

Project Scoring and EnCompass Selection. Three criteria were identified for scoring, including pricing (55 of a total possible 100 points), capacity deliverability and risk (30 points), and bidder strength and execution (15 points). One criterion, Environmental Justice Impacts, could have up to 10 points added or 10 points deducted from the bid score (NSPM bids only). In addition, five criteria were identified that could reduce the overall proposal score. These criteria included lack of certified diverse suppliers (5 points), exceptions to the BT Purchase and Sale Term Sheet (10 points), transmission congestion at the resource location relative to Company load (15 points), not submitting a NOIR for MNEC-interconnected bids (10 points, NSPM bids only), and not responding to Company cure questions in a timely manner (5 points). In addition, bonus points were awarded to early COD projects, 20 points for projects with a COD before June 1, 2027, and 10 points for projects with a COD before June 1, 2028.

To perform these reviews, an RFP Evaluation Process document (“Evaluation Guide") was prepared by the Company, with the IA’s assistance, describing in detail the evaluation process to be conducted by the RFP evaluation and due diligence teams once bids were submitted. Detailed proposal review forms were created with a series of questions grouped by subject area and assigned to members of the RFP evaluation/due diligence teams with relevant subject matter knowledge.

Scoring questions were developed to be used in assessing the criteria scores. The price evaluation was based on financial modelling of the projects Levelized Cost of Electricity (“LCOE”) for solar and wind projects, Levelized Cost of Capacity (“LCOC”) for standalone storage projects, and a combination of LCOE and LCOC for hybrid projects. Given the difficulty of comparing the economics of 1) solar and wind bids, 2) solar and wind plus storage hybrid bids, and 3) standalone storage bids, a procedure was developed for modeling the bids of each type with the highest overall scores in the EnCompass model to select the lowest cost portfolio of bids.

Once the MNEC approved route was selected by the MPUC, the Contingent bids shortlisted for further evaluation were required to be updated to reflect the tie-line cost. These bids were then re-examined with respect to relevant threshold and scoring questions associated with the tie-line. For Contingent Bids passing this threshold review, the bids were rescored with the Traditional bids to determine if the bids continued to score high enough to be selected to the final shortlist.

2.2.6 RFP Market Assessment

Prior to the submission of RFP bids, the Company completed a market assessment to assess the supply of solar, wind and storage resources that could be bid into the RFP. This assessment was reviewed by the IA. The Company concluded that there were a significant number of known projects that could potentially meet the RFP requirements, indicating that the RFP bidding likely would be competitive.

3. RFP Process

This section described the procedural steps that took place during the RFP process. Key procedural steps included:

- The NSPM RFP was posted on the Company 2024 NSPM RFP website on June 28, 2024.[16] Prior to the posting of the NSPM RFP, an informational compliance filing was submitted in MPUC Docket E002/M-24-230 on June 21, 2024. The NSPW RFP was posted on the Company's 2024 NSPW RFP website on July 1, 2024, and a modified version was posted on July 2, 2024.[17]

- Throughout the RFP process, the Company used a specific email address to receive proposals and to communicate with bidders (NSP2024RFP@xcelenergy.com).

- A bidder conference was held on July 24, 2024 for the NSPM RFP and on July 25, 2024 for the NSPW RFP summarizing the RFP and allowing potential bidders to ask clarifying questions. Prior to the bidder conferences, meeting notices were forwarded to an email list of developers maintained by the Company. The IA attended both conferences. The bidder conferences were recorded and posted on the RFP websites for review by potential bidders unable to attend the conferences.

- Eleven prospective bidders submitted an optional Notice of Intent to bid in August 2024.

- Questions on the RFP were submitted by potential bidders through the RFP question deadline date of September 8, 2024. A total of 58 questions were submitted, resulting in eight sets of questions and answers being posted on the RFP websites for all potential bidders to review. The IA reviewed all questions and answers prior to Company posting. Of the 58 questions, 36 were related to both the NSPM and NSPW RFPs, 17 were related specifically to the NSPM RFP and 5 were related specifically to the NSPW RFP. The 58 questions covered seven general topics, as summarized in Table 1.

Table 1: Bidder Questions by Topic

Question Topic	Number of Questions
Administrative	10
Contingent Bids	5
Interconnection	14
Location	5
RFP Structure	5
Studies and Permits	5
Terms and Contracts	11
Other	3

[16] https://mn.my.xcelenergy.com/s/renewable/developers/2024-rfp
[17] https://mn.my.xcelenergy.com/s/renewable/developers/2024-nspw-rfp. The NSPW RFP was updated on July 2, 2024 with respect to distribution interconnection requirements.

- In the NSPM RFP, three Company self-build bids were submitted on September 17, 2024 in accordance with the NSPM RFP schedule submission deadline for self-build bids. Per MPUC Modified Track 2 requirements, a Company filing was submitted describing the self-build bids in MPUC Docket No. E002/M-24-230 on September 25, 2024.

- A total of 38 third-party bids were submitted by September 18, 2024, in accordance with the RFP schedule submission deadline. A number of these bids were alternative variations for procurement of the same resource or for an option to add storage to a solar resource at the same site.

- Of the total 41 bids, 34 were for transmission interconnected projects and 7 were for distribution interconnected projects; 17 were BTs, 21 were PPAs, and 3 were self-build.

- In total, there were 30 distinct projects proposed by 14 different bidders representing about 1,475 MW of solar capacity, 410 MW of wind capacity, 1,340 MW of standalone storage, and 1,180 MW of solar plus storage capacity.[18] Two of the proposed solar projects also included a separate solar plus storage hybrid bid using the same underlying solar resource.

- Of the total 30 distinct project sites, 20 were physically located in Minnesota with 3,791 MW of distinct capacity, 3 in South Dakota with 230 MW of distinct capacity, 6 in Wisconsin with 210 MW of distinct capacity, and one in a state not eligible under the RFP requirements.

- In the NSPM RFP, three Contingent option bids were received for interconnection to the MNEC Project. No bids were received in the NSPW RFP for interconnection to the King Gen-Tie.

3.1 Proposal Evaluations

3.1.1 Completeness and Threshold Reviews

Using the proposal review forms developed prior to bid submissions, subject matter experts from the Company performed a detailed examination of each of the qualification criteria for each proposal. Where needed, a series of follow-up questions were prepared by the Company and sent to individual bidders from the RFP email address. In general, these questions focused on any criteria where qualifications were not met or where further clarification was required. The IA monitored all communications with bidders throughout this process by being copied on all bidder question emails submitted to or from the RFP mailbox during the due diligence process.

As shown in Table 2, **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** of the 41 bids were withdrawn by bidders during the Completeness and Threshold Review process and **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** bids did not pass the Threshold review. **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** technical variations of the remaining **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** bids were excluded from the scoring stage as less economically desirable than

[18] No wind plus storage bids were submitted. The listed solar plus storage capacity includes the capacity for two project sites that were separately bid as solar only.

remaining bids for the same project.[19] This resulted in **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** bids reaching the scoring stage.

Table 2: Bid Evaluations by Stage

Category	No. of Bids
[PROTECTED DATA BEGINS	
	PROTECTED DATA ENDS]

Of the **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** bids that did not pass the Threshold review, the main reasons included not meeting the site control, location, interconnection, and technology threshold criteria. Throughout the Threshold review process, all bidders were given ample opportunity to address or cure deficiencies identified by the Company evaluation team. The IA monitored and reviewed the Threshold review forms for each proposal and agreed with Company findings.

3.1.2 Key Parameter Review and Scoring

The **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** bids that reached the scoring stage comprised **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** distinct projects: **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** solar projects representing **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** of capacity and **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** standalone storage projects representing **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** of capacity. No wind or solar plus storage hybrid projects made it to the scoring stage. Of the **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** scored bids, **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** were BTs, **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** were PPAs, and **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** were self-build projects.[20]

Each of the remaining **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** bids were analyzed using the scoring evaluation guidelines summarized in the RFP Evaluation Guide discussed above. Certain bids took longer to reach, or fail to reach, the scoring stage as cure

[19] For example, after Company review, a bid for a standalone storage project without augmentation was excluded in favor of the bid for the same project with augmentation.

[20] Some BT bidders offered both the required standard BT bid and an alternative bid with proposed redlines to the BT term sheet for their project. After an evaluation of the price/risk tradeoff, **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** BT bids were selected to be scored using the proposed alternative bid.

questions were issued, responses were received, and follow-up cure questions were issued over the course of the RFP evaluation process.

A series of analytic steps were then applied, in accordance with the RFP Evaluation Guide, to select the shortlisted bids, as summarized in Table 3 and discussed in turn below.

Table 3: Remaining Bids and Sites after Each Analytic Step

Analytic Step	Remaining Bids	Remaining Unique Projects	Remaining Unique Solar MW	Remaining Unique Storage MW
[PROTECTED DATA BEGINS				
			PROTECTED DATA ENDS]	

<u>Step 1: Scoring.</u> Using the scoring approach outlined in the RFP Evaluation Guide and the scoring sheets for each bid, the remaining **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** bids were scored based on the price and non-price scoring factors described above. The pricing component of the bid scores was calculated for solar bids using Company LCOE models and for standalone storage using Company LCOC models that were reviewed by the IA prior to the RFP evaluation process.[21]

Similarly, in accordance with the RFP Evaluation Guide, the other RFP scoring criteria, including capacity deliverability and risk, bidder strength and execution, environmental justice impacts (NSPM bids only), use of diverse suppliers, transmission congestion, and COD bonus points were scored. Each of these scores was reviewed and accepted by the IA. Total scores for each of the bids were then calculated and the bids were ranked by total score. Bids were ranked separately for the remaining solar only bids and standalone storage bids.

<u>Step 3: Minimum Quality Risk Screen.</u> To qualify for evaluation in EnCompass, each scored bid needed to exceed the minimum **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS] As shown in Table 3, after approval by the IA, all remaining bids

[21] **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS]

passed this screen, leaving **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** remaining bids.

Step 4: EnCompass Quantity Limit. **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** The collective MW quantity of the remaining solar projects after Step 3 exceeded this **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** threshold, and, as a result, the two lowest scoring solar bids were excluded. As shown in Table 3, after approval by the IA, the remaining **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** bids were then modeled in EnCompass.

<u>*Step 5: EnCompass Analysis.*</u> The remaining bids were modeled in EnCompass using the approach developed in the RFP Evaluation Guide. In the EnCompass modeling, the renewable capacity met by generic resources in 2027 and 2028 in the IRP modeling was removed. Then, the remaining RFP bids were allowed to be selected by the EnCompass model to replace these generic resources. Distinct projects could only be selected once; for example, if a solar BT and a solar PPA were bid by the same bidder for the same site, the EnCompass model could choose only one. In the EnCompass analysis, the lowest cost bid type (BT or PPA) was selected for those projects with both options. The EnCompass model used in the final selection process had the same base input assumptions used in the IRP modeling, other than incorporating the latest (2^{nd} half of 2024) NSP load forecast for the Upper Midwest. The updated load forecast projected a peak load by 2030 over 1,000 MW higher than the IRP load forecast. This peak load increase indicated that more than the 1,600 MW originally sought in the RFPs likely would be economic. As shown in Table 3, the EnCompass analysis eliminated **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** bids, leaving **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** bids for **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** distinct projects remaining for consideration.

<u>*Step 6: Cost-Effectiveness Screen.*</u> A final cost screen was applied to ensure that the bids selected would be cost-effective for Company customers. After review and approval by the IA, this cost screen eliminated **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** This left **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** remaining bids across **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** different projects, as shown in Table 3. Of these **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** remaining bids, **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** were Traditional Bids and **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** were Contingent Bids.

3.1.3 Shortlist Selection

With the review and approval of the IA, the remaining **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** Traditional Bids were selected for the shortlist. The Solar Traditional Bids selected for the shortlist are summarized in Table 4, which is sorted from the highest to lowest total score. Table 4 lists the bid name, the bidder, the capacity in MW for each bid, the state in which the project is located, the term in years for PPAs or whether the bid is a BT or self-build (SB), whether the bid is on the distribution (D) or transmission (T) system, the bid's LCOE and the total bid score.

Table 4: Shortlisted Solar Traditional Bids

Bid	Bidder	MW	State	PPA Term	D or T	LCOE $/MWh	Total Score
[PROTECTED DATA BEGINS							
							PROTECTED DATA ENDS]

Table 5 shows the same information for the shortlisted Standalone Energy Storage (ES) Traditional Bids, with the bid's LCOC shown rather than LCOE.

Table 5: Shortlisted Standalone Energy Storage (ES) Traditional Bids

Bid	Bidder	MW	State	PPA Term	D or T	LCOC $/kW-yr	Total Score
[PROTECTED DATA BEGINS							
							PROTECTED DATA ENDS]

For the **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** Traditional Bids on the shortlist:

- There were **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** distinct projects, **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** solar projects with **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** of capacity and **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** standalone storage projects with **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** of capacity.

- **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** were PPAs, **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** were BTs, and **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** were self-builds.

- **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** were transmission interconnected and **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** were distribution connected.

- **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** were physically located in Minnesota, **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** in South Dakota, and **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** in Wisconsin.

The IA closely monitored the project scoring process and the selection of the Traditional Bid shortlist and approved the selections on January 10, 2025. This concluded the IA's monitoring of the RFP process for Traditional Bids.

3.1.3.1 Final Shortlist Selection for Contingent Bids

Based on their initial scoring, **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** MNEC Project Contingent Bids were shortlisted in January 2025 for further evaluation once the final routing of the MNEC Project was approved by the MPUC. There were **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** BT projects and one self-build project summing to **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** of solar capacity in this category. After January 2025, the IA continued to monitor the bidder communications and evaluations of the Contingent Bids shortlisted for further evaluation.

The Contingent Bids were evaluated for final shortlist selection in accordance with the NSPM RFP once the final routing of the MNEC Project was verbally approved by the MPUC on April 10, 2025. Once the MPUC approval was received, the **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** Contingent Bid bidders were notified individually that an updated bid submission was due on May 16, 2025 (the updated submission for the self-build Contingent Bid was due one day earlier, on May 15, 2025). In particular, the updated bids were required to include the cost of the tie line in their bids, including the cost of tie-line land acquisition.

[PROTECTED DATA BEGINS PROTECTED DATA ENDS]

The final Contingent bid, a 200 MW self-build solar unit, passed the Contingent Bid Update Threshold Review, scored high enough with its updated pricing that it would have been among the short-listed bids with respect to scoring in the January 2025 shortlist analysis, continued to pass the Quality Screen, and continued to pass the Cost-Effectiveness Screen. As such, with approval of the IA, this bid was approved for selection to the final shortlist on July 24, 2025.

In sum, with the review and approval of the IA, **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** distinct projects from **[PROTECTED DATA BEGINS**

[PROTECTED DATA BEGINS PROTECTED DATA ENDS] of solar capacity and **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** of standalone storage capacity. Overall, this yielded a total of approximately **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** of Traditional and Contingent Bids selected for the final short list. Relative to the 1,600 MW initially sought in the RFP, this overall total of **[PROTECTED DATA BEGINS** [redacted] **PROTECTED DATA ENDS]** is consistent with the increase by 2030 in NSP capacity and energy needs in the latest load forecast and hedge against the potential for some shortlisted projects to not reach the final contracting stage.

4. Recommendations

The IA worked closely with the Company throughout the development of the solicitation, the administration of the bidding, and the evaluation of the bids. The Company adopted Guidehouse recommendations throughout this process and we have no specific additional recommendations at this time. We expect that additional refinements to the RFP documents and process will be made in future Company RFPs to reflect: 1) the questions from the bidders during the RFP, 2) the responses of bidders in their submitted proposals to the various forms and other RFP requests for information, and 3) any additional best practices developed through other renewable and storage RFPs in the U.S. and shared with the Company by Guidehouse.

5. Findings

The following is our independent assessment of whether the goals of the RFP were achieved and whether the overall RFP process was fair and consistent.

Guidehouse has completed its assessment of the RFPs and finds the following:

- The Guidehouse overall assessment is that the RFPs were conducted on a fair and consistent basis, with over **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** of solar energy and standalone storage projects successfully selected for contract negotiations under the Traditional Bid and Contingent Bid processes. This was more than the 1,600 MW originally sought in the RFPs, consistent with the increase in NSP capacity and energy needs under the updated load forecast and the potential for some shortlisted projects to not reach the final contracting stage.
- The RFP completeness and material threshold evaluations were performed for each proposal on a fair and consistent basis using the process described in the RFP. Respondents were given ample opportunity to cure deficiencies within a reasonable period. The criteria used were reasonable and consistent with similar criteria we have developed or observed.
- The RFP scoring and selection stage, including the economic and noneconomic scoring and EnCompass modeling, was performed on a fair and consistent basis using the process described in the RFPs. The criteria used were reasonable, and the limitation of the short-list to the most cost-effective bids was reasonable.
- The selection of the Contingent bids shortlisted for further study and evaluation once the final MNEC Project routing was approved by the MPUC was performed on a fair and consistent basis using the process described in the RFPs. After the MNEC route approval by the MPUC in April 2025, the selection of the Contingent bids for the final shortlist was performed on a fair and consistent basis using the process described in the NSPM RFP.
- There was strong interest in the RFPs, as evidenced by the number of bids received.
- With respect to messages between the Company, interested parties, and respondents, we observed that the Company's responses were timely, consistent, and fair, indicating a high level of engagement by the Company.
- Based on the IA's review and observations, there is no evidence that the evaluation and selection process caused any unfair advantage or disadvantage to any interested party or respondent, including the Company's self-build bid.

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PUBLIC DOCUMENT
NOT-PUBLIC DATA HAS BEEN EXCISED
NOT PUBLIC IN ENTIRETY

Attachment B is marked "NOT PUBLIC" as it contains information the Company considers to be trade secret data as defined by Minn. Stat. §13.37(1)(b). This data includes bid data, details of our project evaluation process, confidential negotiation details, pricing, and other contractual terms. This information has independent economic value from not being generally known to, and not being readily ascertainable by, other parties who could obtain economic value from its disclosure or use.

Attachment B is marked as "Not-Public" in its entirety. Pursuant to Minn. Rule 7829.0500, subp. 3, the Company provides the following description of the excised material:

1. **Nature of the Material:** A description of the bid evaluation process.
2. **Authors:** The Company's Integrated System Planning – Resource Planning & Bidding team.
3. **Importance:** This document discusses the Company's process for evaluating bids into a Modified Track 2 process, including details about bid evaluation criteria. Parties could obtain economic value in future Company resource procurements from the disclosure or use of this document. Knowledge of such information in conjunction with public information in our Petition could also adversely impact future contract negotiations, potentially increasing costs for these services for our customers.
4. **Date the Information was Prepared:** September 2024 (Updated 10/1/2024)