APPLICATION TO THE MINNESOTA PUBLIC UTILITIES COMMISSION FOR APPROVAL OF A COMPETITIVE RESOURCE ACQUISITION PROPOSAL:

LYON COUNTY GENERATING STATION PROPOSAL

MPUC Docket No. E002/CN-23-212

January 2024

Submitted by

Northern States Power Company DBA Xcel Energy

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1. EXECUTIVE SUMMARY.

1.1 Introduction.

Northern States Power Company (NSP), a Minnesota corporation, doing business as Xcel Energy (Xcel Energy or the Company), submits this proposal for consideration by the Minnesota Public Utilities Commission (Commission). We respectfully seek approval of our proposal to construct 420 megawatts (MW) of combustion turbine generator (CT) capacity and associated facilities at a greenfield generating station to be located in Lyon County, Minnesota, with an in-service date of December 2027 (the Lyon County Station or Proposal).

This Proposal provides firm dispatchable generation to ensure reliable service to our customers in a timeframe that aligns with the Commission's finding in the Company's 2019 Integrated Resource Plan (2019 IRP) that "it is more likely than not that Xcel Energy will need up to 800 MW of generic firm dispatchable resources between 2027 and 2029."[1]

Xcel Energy respectfully requests that the Commission select the Lyon County Station and find that it meets Xcel Energy's need for firm dispatchable resources under the terms described in this Proposal.

1.2 Lyon County Station Proposal.

To meet a portion of the need for firm dispatchable generation, Xcel Energy proposes two CTs, totaling approximately 420 MW, in Lyon County, Minnesota, to be in-service in December 2027. Both CTs will be natural gas fired with the capability to co-combust up to 30 percent hydrogen on initial operation. The Lyon County Station is proposed to be located near Garvin, Minnesota, and adjacent to the "Terminal Substation" proposed as part of the Minnesota Energy Connection Project (MNEC) (the Proposal Site). This site also allows the Proposal to tie into the Northern Border natural gas pipeline, which runs through the southwest corner of the site.

The Proposal includes two natural gas F-class turbine generators. The CTs would be equipped with synchronous condenser capability, if available by the time of

[1] *In the Matter of the 2020–2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy,* MPUC Docket No. E-002/RP-19-368, Order Approving Plan with Modifications and Establishing Requirements for Future Filings at 11 (April 15, 2022) (IRP Order).

construction and consistent with project schedule.[2] Each CT can produce approximately 210 MW in summer heat and humidity conditions. The Company anticipates the CTs will have a capacity factor of 5 to 10 percent. The Proposal also includes the following associated facilities:

- On-site operation facilities (control room, offices, warehouse, etc.).
- Two 345 kilovolt (kV) transmission lines that would be located entirely within the parcel to connect the plant to the MNEC Terminal Substation.
- A twelve-inch natural gas supply will come from the Northern Border Pipeline which routes through the southwest corner of the Lyon County Station property. Northern Border will perform the tie-in to the main pipeline and construct a metering and pressure regulating station on the site. At that point, Xcel Energy will continue the piping to the CTs.
- Three 750-kilowatt (kW) emergency diesel generators to provide emergency power.

If selected and constructed, the Lyon County Station would provide flexible peaking generation. Synchronous condenser capability is expected to be available soon after the time of construction. When implemented, the Lyon County Generating Station will also provide required system support for MNEC and the renewable resources that will be interconnected via that line, thus potentially replacing MNEC's synchronous condensers, which are estimated to cost approximately $140 million.[3]

1.2.1 Benefits of the Proposal.

The Lyon County Station offers the following benefits:

- **Reliable peaking firm dispatchable generation**: CTs are some of the best positioned resources to provide flexibility to the system. Combustion turbines are intended to be able to meet evening load ramps, when demand typically increases, as well as start relatively quickly if the grid operator foresees a decline in variable renewable resources. CTs provide significant value to the system for reliability, in providing firm peaking

[2] Alternatively, equipment installation options to allow future conversion will be evaluated.

[3] If synchronous condenser capability is not available for the Lyon County Station, standalone synchronous condensers would be needed to provide reactive support to MNEC.

capacity and energy during occasional extended periods of low renewable output. More specifically, for example, the North American Electric Reliability Corporation (NERC) has recommended in its 2023 Long Term Reliability Assessment report that entities "[a]dd new resources with needed reliability attributes and make existing resources more dependable."[4] NERC further suggests that "[n]atural-gas-fired generators are essential for meeting demand; they are dispatchable at any hour and provide a consistent rated output under a wide range of conditions."[5] The reliability report also recommends better coordination of the gas and electric infrastructure, as well as better extreme weather preparedness to ensure adequate resource availability during prolonged extreme weather events. Our Proposal meets the need for firm dispatchable resources and would provide flexible peaking generation to allow the Company to continue to reliably meet customer needs.

- **System stability support for MNEC**: Because the Lyon County Station would be located at MNEC's proposed "Terminal Substation," the Proposal could also provide required system support for MNEC and the renewable resources that will be interconnected via that line, thus replacing MNEC's synchronous condensers.[6]

- **Small environmental footprint**: The Proposal would impact approximately 40 acres of land and would be co-located adjacent to MNEC facilities and a natural gas pipeline. No impacts to wetlands, waterbodies, rare or unique resources, or other sensitive resources are anticipated.

- **Limited carbon emissions**: The Proposal would result in carbon emissions, but those emissions have been minimized because of the anticipated low capacity factor of the facility and the option to include the

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[4] NERC 2023 Long-Term Reliability Assessment at 10 (Dec. 2023), available at https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2023.pdf (last accessed Jan. 21, 2024).

[5] *Id.*

[6] *In the Matter of the Application of Xcel Energy for A Certificate of Need for Two Gen-Tie Lines from Sherburne County to Lyon County, Minnesota,* MPUC Docket No. E002/CN-22-131, Revised MNEC Certificate of Need Application at 64, n. 66 (May 18, 2023).

ability to co-combust green hydrogen. Likewise, the Proposal would support additional renewable generation on Xcel Energy's system.

- **Use of existing Xcel Energy-owned interconnection**: The Proposal would interconnect to the grid using Xcel Energy's existing and valuable interconnection rights at the Sherburne County Generation Station Substation (Sherco Substation). Thus, the Proposal is not subject to the Midcontinent Independent System Operator (MISO) interconnection queue. Because of MISO requirements related to interconnection re-use, only Xcel Energy-owned facilities are eligible to re-use these interconnection rights.

- **Economical and reliable generation**: The Lyon County Station provides both economical and reliable generation. CTs are economically viable, relative to long duration storage and other firm dispatchable greenfield generation, due to their capital and operating costs. They have a simple design, are easy to start up, require smaller space, have no standby losses, and have lower maintenance costs compared to other forms of firm or intermediate generation. Furthermore, advancements in turbine technology have led to increased heat-to-electricity conversion efficiencies, higher power density, and simplicity of operation compared to existing steam-based power cycles. Adding CTs also requires lower capital investments than other new power plant options, and these peaking plants complement and support our existing generation portfolio and the energy portfolio the Company will build into the future. The addition of peaking capacity allows us to more fully utilize existing, intermediate generation and add additional low-cost renewable generation.

1.2.2 Relationship of Lyon County Station Proposal to Other Company Proposals.

The Commission found that it is more likely than not that the Company will need up to 800 MW of firm dispatchable resources between 2027 and 2029. Given its 420 MW size, this Proposal is intended to be evaluated as part of a larger portfolio of resources to meet that need, including the 447 MW Bison Generating Station Proposal also being submitted by the Company.

In addition, in the 2019 IRP Order, the Commission directed Xcel Energy to include an evaluation of renewable resources and storage that could deliver the grid attributes necessary to meet the identified need. Consistent with this direction, the Company evaluated potential storage options. As a result of that evaluation, the Company is also submitting a proposal for our Sherco West Battery Energy Storage System (BESS) in this proceeding.

1.3 Regulatory Background & Framework.

In its 2019 IRP Order, the Commission found that "it is more likely than not that Xcel Energy will need up to 800 MW of generic firm dispatchable resources between 2027 and 2029." The Commission's finding was not tied to a specific location or technology, and the Commission directed Xcel Energy (in a future resource plan, certificate of need application, or resource acquisition proceeding) to "include an evaluation of renewable resources and storage that can deliver the identified necessary grid attributes…." The Commission's order further specified:

> A. For purposes of Ordering Paragraph 3, "firm dispatchable" means a resource or combination of resources that is able to provide capacity and energy.
>
> B. Other characteristics for a firm dispatchable resource that may be considered include–
>
> 1) energy availability to meet load for extended durations of energy in the context of the system as a whole,
>
> 2) the value from production capabilities during potential system restoration events of unknown duration,
>
> 3) environmental impacts,
>
> 4) costs, and
>
> 5) the ability to foster integration of renewable resources.
>
> C. Xcel shall analyze this likely need based on up-to-date system-wide modeling, including corrected modeling of wind fleet variability and of exchanges with MISO, in order to –
>
> 1) establish the capacity, energy, resource adequacy, energy availability, ancillary service, and reliability needs, and

> 2) quantify and compare the contribution of the electric system attributes from the different resource options considered to meet the identified grid needs.

The Commission further ordered that the Xcel-Bid Contested Case/Track 2 contested case bidding process must be used for the firm dispatchable resources identified in the 2019 IRP Order.[7] This process was first approved in the Company's 2004 Resource Plan (Docket No. E002/RP-04-1752). In summary, when the Company is proposing a self-built alternative, the Commission specified a certificate of need-like process where:

- The Company submits a detailed filing regarding its proposal containing information as laid out in Minnesota rules and statutes governing certificate of need applications.
- On the same date, interested competitors provide their proposals in similar certificate-of-need-like detail, including proposed contract terms.
- A contested case is conducted before an administrative law judge, with findings and recommendations to be provided to the Commission.
- The Commission considers the developed record and issues its selection decision and grants certificates of need as appropriate.
- The Company and any selected independent power supplier have four months to negotiate a Power Purchase Agreement or Purchase and Sale Agreement for Commission approval.

Xcel Energy initiated this docket on May 24, 2023, with its Notice Petition. In its November 3, 2023, Order Approving Petition and Requiring Compliance Filing, the Commission directed the Company and any competitors to file their proposals with the Commission by January 22, 2024. In the same order, the Commission also approved, with modifications, the Resource Attributes Matrix, Applicant Guide and Filing Requirements, and the proposed evaluation process. Xcel Energy revised these documents consistent with the Commission's order and, on November 13, 2023, submitted a compliance filing confirming that it would publish the requisite materials on November 22, 2023.[8]

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[7] IRP Order at 33, ¶ 6(C).

[8] *See* Compliance Filing (Nov. 13, 2023) (eDocket No. 202311-200447-01).

1.4 Resource Need.

1.4.1 2019 IRP.

This proceeding arises out of the lengthy and comprehensive review of the Company's resource needs as part of the 2019 IRP. In its July 1, 2019 Integrated Resource Plan (Initial Preferred Plan), Xcel Energy proposed a plan that would reduce carbon emissions 80 percent by 2030, and provide 100 percent carbon-free energy by 2050.[9] Xcel Energy's proposal included the elimination of coal-fired generation from its system by 2030 and, among other things, taking ownership of the Mankato Energy Center (MEC) combined cycle (CC) and construct a new CC at the Sherco site (Sherco CC).[10] The Initial Preferred Plan explained that those dispatchable resources "will be critical as we retire 2,400 MW of coal-fired baseload...."[11] After conducting the additional modeling required by the Commission, Xcel Energy filed its Supplement Preferred Plan.[12] The Supplement shared the same key elements as the Initial Preferred Plan and continued to include earlier retirements of coal units, as well as approximately 800 MW of CC at the Sherco site.[13] The Supplement Preferred Plan did not include the MEC acquisition because the Commission issued an order on December 18, 2019, denying the proposed acquisition.[14]

On June 25, 2021, Xcel Energy submitted its Alternate Plan. Like the Initial and Supplement Preferred Plans, the Alternate Plan continued to include the retirement of the Company's coal generation by 2030.[15] The Company explained that, although it continued to believe that the proposed "Sherco CC would be a valuable system resource

[9] Reply Comments at 131 (June 25, 2021) (eDocket Nos. 20216-175386-01 (Public) and 20216-175386-02 (Trade Secret)) (Alternate Plan).

[10] Alternate Plan at 16.

[11] Initial Preferred Plan at 24 (July 1, 2019) (eDocket Nos. 20197-154051-01 (Public) and 20197-154051-02 (Trade Secret)) (Initial Preferred Plan).

[12] Supplement Preferred Plan (June 30, 2020) (eDocket Nos. 20206-164371-01 (Public) and 20206-164371-02 (Trade Secret) (Supplement Preferred Plan).

[13] Supplement Preferred Plan at 76.

[14] *In the Matter of a Petition by Northern States Power Company, d/b/a Xcel Energy, for Approval of the Acquisition of the Mankato Energy Center,* MPUC Docket No. E002/PA-18-702, Order Denying Petition and Requiring Supplemental Modeling at 10 (Dec. 18, 2019).

[15] Alternate Plan at 1.

and a reasonable and appropriate solution to retiring more than 2,400 MW of coal generation"[16] while maintaining system stability and providing dispatchable energy, the Alternate Plan "represents the best path forward" for customers and stakeholders.[17] The Alternate Plan "achieves greater emissions reductions, decreases customer costs, maintains reliability, adds more renewables in a faster timeframe, reduces our reliance on natural gas, and supports a new and more resilient approach to system restoration."[18]

Because the Alternate Plan did not include the Sherco CC, Xcel Energy noted that "the Company will – for the first time since the 1970s – be operating a system without central station power in Becker, which represents a fundamental shift in the way we plan and operate our system."[19] As part of its analysis in the Alternate Plan of operating without a Sherco CC, the Company identified the need for other dispatchable resources that could support grid reliability and resiliency in light of the increased renewables being added to the system and the baseload units being retired. More specifically, and in relevant part here, the Company proposed 400 MW hydrogen-capable CTs in Lyon County, Minnesota, and 400 MW CTs near Fargo, North Dakota.[20] The Lyon County Station would interconnect via the proposed MNEC transmission line, which will reutilize Xcel Energy's existing interconnection rights at Sherco and also facilitate the interconnection of thousands of MW of renewable resources.[21]

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[16] Alternate Plan at 2.

[17] *Id.*

[18] *Id.*

[19] *Id.*

[20] Alternate Plan at 37.

[21] There are specific requirements governing generator replacement and the ownership of resources that reutilize these interconnection rights. MISO's generator replacement rules are set out in Attachment X of the MISO Tariff, which contains MISO's Generator Interconnection Procedures or "GIPs." The general timing rules of generator interconnection replacement under the MISO Tariff require (1) that a request for generator interconnection replacement be submitted at least one year prior to the date that an existing generation facility will cease operation, Attach. X § 3.7.1(ii), and (2) the expected commercial operation date for a replacement facility must be within three years of the date that the existing facility ceases operation, Attach. X § 3.3.1.11 These generator interconnection rules allow for the owner of an existing facility to request to itself replace the facility with another facility. The rules do not allow the owner of an existing facility to submit a request for a third party to build a replacement facility that will use the owner's existing interconnection rights. The Lyon County

Xcel Energy understands that some parties have and will continue to advocate to eliminate the firm dispatchable generation additions included in the Alternate Plan; however, the Company explained in the IRP proceeding that it does not believe that is prudent.[22] As the bulk power system operator and infrastructure provider charged with providing critical power to over one million customers throughout the Upper Midwest, Xcel Energy needs sufficient firm dispatchable resources to maximize renewable capability and production and to ensure a reliable and affordable clean energy transition.[23] The replacement firm dispatchable generation serves an important role for system stability and other reliability needs, and can support capacity and energy needs when variable renewables are not available (such as the polar vortex of 2019 or the cold weather event our region experienced in 2021).[24] Yet on average, these resources have relatively low capacity factors – meaning their contribution to carbon emissions is also is relatively low.[25] Whereas modeling results showed the Sherco CC running at an 80 percent capacity factor, the CT resources modeled in the Alternate Plan average 5 percent or lower – sometimes substantially lower – throughout the planning period.[26] In this way, the CT resources are a necessary insurance policy that enables us to pursue deep carbon reduction and higher and higher levels of renewable penetration while ensuring that our customers will receive reliable and affordable service during the hottest and coldest days of the year, even when renewable generation is limited or non-existent.[27]

At the conclusion of the 2019 IRP proceeding, the Commission found that "it is more likely than not that there will be a need for approximately, but not more than, 800 MW of generic firm dispatchable resources between 2027 and 2029."[28]

Station was modeled to utilize Sherco Unit 1's interconnection, which has a resource replacement window of 2027-29.

[22] Alternate Plan at 23.

[23] *Id.*

[24] *Id.*

[25] *Id.*

[26] *Id.*

[27] *Id.*

[28] IRP Order at 32, ¶ 3.

1.4.2 2024-2040 Resource Plan.

Xcel Energy anticipates filing its next Resource Plan in February 2024. That plan will include up-to-date system-wide modeling, and we believe it will again affirm the need for firm dispatchable resources to continue to reliably meet the needs of our customers.

Xcel Energy will file the updated forecast and other relevant information from the forthcoming IRP in this docket after it is efiled.

1.5 Environmental Impacts.

The Lyon County Station has limited environmental impacts. It is proposed to be located adjacent to an existing natural gas pipeline and proposed MNEC facilities, avoiding the need for substantial new additional infrastructure and related environmental impacts. The Proposal would be sited to avoid wetlands, waterbodies, and sensitive resources. The project will not be a major source of air pollutants and will not require a Prevention of Significant Deterioration air permit.

1.6 Alternatives.

Section 5 of this Application includes the Company's analysis of alternatives to this Proposal. As detailed further in that section, new CTs like this Proposal are critical to the transition to carbon-free energy because we do not currently have other options that meet our high capacity, long duration, affordability needs. Additionally, the Lyon County Station is proposed to be hydrogen-ready and, therefore, may also play a significant role in our efforts to reduce carbon emissions and transition to clean energy. The Lyon County Station, in particular, is well-positioned to make sure of existing and planned facilities, given its proximity to an existing natural gas pipeline and the proposed MNEC transmission facilities. Given these attributes, this Proposal is the ideal complement to high penetrations of intermittent renewable resources.

For these reasons, and as further detailed in this Application, pursuant to Minn. Stat. §§ 216B.2422, subd. 4, and 216B.243, subd. 3a, the Proposal is less expensive than a project generating renewable energy and/or otherwise in the public interest.

1.7 Certificate of Need Criteria.

Minnesota rules and statutes specify the criteria the Commission should apply in determining whether to grant a Certificate of Need. Subdivision 3 of Minn. Stat. § 216B.243 identifies the criteria the Commission must evaluate when assessing need. Minnesota Rule 7849.0120 further provides that the Commission shall grant a

Certificate of Need if the Commission determines that the proposal satisfies the following criteria:

(A) *The probable result of denial would be an adverse effect upon the future adequacy, reliability, or efficiency of energy supply to the applicant, to the applicant's customers, or to the people of Minnesota and neighboring states*;

Denial of this Proposal would result in adverse effects upon the present and future efficiency of energy supply to the Minnesota electric customers and other end users. The Proposal would supply Xcel Energy with firm dispatchable generation needed to continue to reliably serve customers after the retirement of the Company's few remaining coal-fired units. Likewise, because of the stability support the Proposal would provide to MNEC, the Proposal would help to facilitate thousands of megawatts of new renewable generation on Xcel Energy's system.

(B) *A more reasonable and prudent alternative to the proposed facility has not been demonstrated by a preponderance of the evidence on the record*;

Xcel Energy anticipates that the Lyon County Station will be demonstrated to be a reasonable and prudent component of a larger portfolio to meet the Company's need for up to 800 MW of firm dispatchable generation. The Proposal would provide flexible peaking generation, as well as ancillary services to MNEC. Likewise, the Proposal would result in limited environmental impacts and has been designed to minimize carbon emissions and ensure that the Company will be in compliance with Minnesota's 100 percent by 2040 standard.

(C) *By a preponderance of the evidence on the record, the proposed facility, or a suitable modification of the facility, will provide benefits to society in a manner compatible with protecting the natural and socioeconomic environments, including human health*;

The facility is proposed to be sited to avoid and minimize environmental impacts and will be designed to employ mitigation measures to reduce emissions. *See* Section 6 herein. The Proposal will also help ensure that the Company will be in compliance with Minnesota's 100 percent by 2040 standard.

(D) *The record does not demonstrate that the design, construction, or operation of the proposed facility, or a suitable modification of the facility, will fail to comply with relevant policies, rules, and regulations of other state and federal agencies and local governments*.

The Proposal would comply with all relevant policies, rules, and regulations. Xcel Energy will secure all necessary permits and authorizations for the Proposal, and the

Proposal has been designed to minimize carbon emissions and ensure that the Company will be in compliance with Minnesota 100 percent by 2040 standard.

(E) *Socially beneficial uses of the output of the facility;*

Because it would support the Company's ability to continue to provide reliable electric service to its customers, the Proposal helps to ensure continued economic vitality in the areas we serve.

(F) *Promotional activities that may have given rise to the demand for the facility; and*

Xcel Energy does not have programs promoting the sale of electricity that would have given rise to the demand for this facility.

(G) *Effects of the facility in inducing future development.*

See (A).

2. GENERAL INFORMATION.

2.1 Applicant Information

The applicant's complete name and address, telephone number are:

Northern States Power Company, a Minnesota corporation
Xcel Energy
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Minneapolis, Minnesota 55401
(612) 330-5500

The Company official responsible for this filing is:

Bria Shea
Regional Vice President, Regulatory Policy
Xcel Energy
414 Nicollet Mall, 401 – 7th Floor
Minneapolis, Minnesota 55401
(612) 330-6064

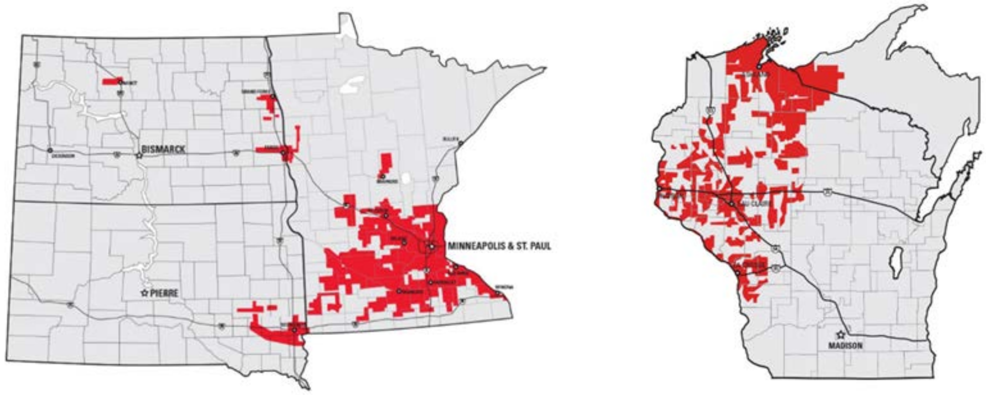
2.2 Description of Business and Service Area

Northern States Power Company (NSP) is a public utility under the laws of the state of Minnesota. The legal name of Xcel Energy is Northern States Power Company, a Minnesota corporation. NSP and its parent public utility holding company, Xcel Energy Inc., (XEI) are headquartered in Minneapolis, Minnesota.

XEI is a public utility that generates electrical power, and transmits, distributes, and sells it to residential and business customers within service territories assigned by state regulators in parts of Minnesota, Wisconsin, South Dakota, North Dakota, and the upper peninsula of Michigan.

The Company and Northern States Power Company, a Wisconsin corporation (NSPW), collectively the NSP Companies, own and operate the five-state integrated NSP System pursuant to the terms of the Federal Energy Regulatory Commission (FERC) approved Interchange Agreement. The NSP Companies have about 1.8 million electricity customers in the upper Midwest. Figure 2--1 shows the Company's upper Midwest service territories in the states of Minnesota, Wisconsin, Michigan, North Dakota and South Dakota.

Figure 2-1: Xcel Energy Upper Midwest Service Territory



Approximately 89 percent of our NSP customers are residential, with commercial and industrial customers comprising most of the remaining 11 percent. The distribution of electricity sales by type of customer, however, is significantly different. Residential customers make up approximately 23 percent of electricity sales, with commercial, industrial, and other customers making up most of the remaining 77 percent.

The Company owns and operates multiple electric generation facilities serving this area using a variety of technologies and fuels, including coal, natural gas, wind, solar, hydro, refuse derived fuel (RDF), and nuclear. Additional wind, solar, landfill gas, biomass, and hydropower are also included in our generation portfolio through purchased power agreements.

2.3 Competitive Resource Acquisition Process.

The Commission indicated in the Company's 2004 and 2007 Resource Plan dockets that the Company should rely on competitive processes as much as possible to meet its resource requirements. Thus, the Company has conducted a number of bidding processes using a Request for Proposals (RFP) to acquire new resources. The RFP process involves reviewing proposals received from developers, selecting the most cost-effective projects, negotiating purchase agreements, and requesting the Commission's review and approval of the purchase agreements.

In the 2004 Resource Plan (Docket No. E002/RP-04-1752), the Commission approved a separate process that uses a certificate of need procedural framework whenever the Company proposes a self-build option in the competitive resource procurement process. Under the Track 2 process, bidders, including the Company, must provide information otherwise required in a certificate of need proceeding unless the Commission has indicated exemptions apply.

On April 15, 2022, the Commission approved our 2019 Resource Plan (Docket No. E-002/RP-19-368) and found it more likely than not that the Company would have a need for approximately, but not more than, 800 MW of generic firm dispatchable resources between 2027 and 2029. [29] The Commission required that the Company utilize the Track 2 process to identify and evaluate options to fulfill this firm dispatchable resource need. [30]

2.3.1 Certificate of Need Standard Applies.

When reviewing proposals in the Track 2 process, the Commission explained that the "[c]ertificate of need filing requirements and decision criteria are clear, comprehensive, directly relevant . . . , and easily transferable to th[is] resource procurement process." [31] The standard of review for the selection of a resource in this proceeding is that established by Minnesota Rule 7849.0120, which states that a certificate of need must be granted upon the Commission determining the following four decision criteria have been met:

A. The probable result of denial would be an adverse effect upon the future adequacy, reliability, or efficiency of energy supply to the applicant, to the applicant's customers, or to the people of Minnesota and neighboring states;

B. A more reasonable and prudent alternative to the proposed facility has not been demonstrated by a preponderance of the evidence on the record;

C. A preponderance of record evidence shows the proposed facility, or a suitable modification of the facility, will provide benefits to

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[29] IRP Order at 32, ¶ 3.

[30] IRP Order at 33, ¶ 6A.

[31] *In the Matter of Northern States Power Company d/b/a Xcel Energy's Application for Approval of its 2004 Resource Plan*, MPUC Docket No. E002/RP-04-1752, Order Establishing Resource Acquisition Process, Establishing Bidding Process Under Minn. Stat. § 216B.2422, Subd. 5, and Requiring Compliance Filing at 6-7 (May 31, 2006).

society in a manner compatible with protecting the natural and socioeconomic environments, including human health; and

D. The record does not demonstrate that the design, construction, or operation of the proposed facility, or a suitable modification of the facility, will fail to comply with relevant policies, rules, and regulations of other state and federal agencies and local governments.

Application of this standard allows the Commission to consider all aspects of the Company's Proposal to determine whether it is in our customers' interest to proceed. This standard also provides a robust framework for the Commission to analyze and compare alternatives that are submitted into the record through the Track 2 process.

2.3.2 Evaluation Considerations.

On May 24, 2023, the Company filed a petition under the Track 2 process requesting permission to initiate a competitive resource acquisition process to acquire up to 800 MW of firm dispatchable resources. The Company suggested approximately 60 metrics and a multi-phase process, focusing on evaluating attributes like resource capacity, energy availability, value of production capabilities during system restoration, environmental impacts, costs, and the ability to foster integration of renewable resources.

On November 3, 2023, the Commission approved the Company's petition proceeding materials subject to modifications. To accomplish the process in a timely manner, the Commission ordered a procedural schedule in which provided for:

- November 13, 2023: Compliance filing
- November 22, 2023: Xcel Energy Notice Published
- January 22, 2024: Xcel Energy and Interested Competitors File Proposals to Meet the Need
- March 28, 2024: Commission Determination of Completeness, referral to the Office of Administrative Hearings (OAH), if warranted
- October 25, 2024: Administrative Law Judge's Report, if referred to OAH
- December 19, 2024: Commission decision on competitive process

In its November 3, 2023, Order, the Commission approved the process for evaluating proposals in this docket. The five phases of the process include:

1 – Threshold requirement per proposal

2 – Individual scoring per proposal

3 – Portfolio optimization in EnCompass

4 – Portfolio viability assessment and scoring

5 – Cost of value modeling and portfolio selection

The first phase will occur as part of the Commission's completeness review. Phases 2 through 5 will be addressed through the remainder of this administrative proceeding.

The Commission also approved a revised resource attributes matrix which identifies the metrics by which proposals will be evaluated, and at which stage of the process. The attribute categories include: capacity; energy availability; blackstart and system restoration; environmental impacts; costs; flexibility, essential reliability services; bidder financial strength and experience; and, energy justice.

On November 13, 2023, the Company filed a compliance filing with updated materials to align with the Commission's November 3, 2023, Order; and on November 22, 2023, the Company published the Notice.

2.4 Related Permit and Approvals.

2.4.1 Commission Approvals.

The Proposal would require a site permit from the Commission because it would be a large electric generating plant pursuant to Minn. Stat. §§ 216E.01, subd. 5, and 216E.03, subd. 1. The 345-kV gen-tie lines that will connect the Lyon County Station to the MNEC Terminal Substation are also anticipated to require a route permit from the Commission because will likely be greater than 1,500 feet in length.

The Company is evaluating the timing and other considerations related to this permitting process and, if this Proposal is selected, plans to commence the permitting process in 2025 to facilitate the start of construction by April 2026 and an in-service date of December 2027.

2.4.2 Other Permits and Approvals.

Table 2-1 below identifies other permits or approvals that may be required for the Proposal.

Table 2-1: Potential Permits / Approvals Required

Agency	Type of Approval / Review	Proposed Activity
Federal		
Federal Aviation Administration (FAA)	Notice of Proposed Construction, Determination of No Hazard	Construction of stack and use of cranes.
U.S. Environmental Protection Agency (USEPA)	Spill Prevention, Control, and Countermeasure (SPCC) Plan	Required if the facility will have 1,320 gallons or more of aboveground petroleum storage capacity in 55-gallon-sized or larger containers (or 42,000 gallons in underground storage not regulated by underground storage tank rules).
USEPA	Acid Rain permit (Title IV Permit)	New and affected utility units that serve generators with total nameplate capacity greater than 25 MWe is required to obtain an acid rain permit.
U.S. Fish and Wildlife Service (USFWS), Ecological Services	Section 7 Threatened and Endangered Species Consultation and Clearance	If the Proposal could potentially impact protected species or their respective habitat, or if a Section 404 and/or NPDES permit is required, then USFWS must be consulted. USFWS will determine the level of effort needed for the Proposal to proceed (e.g., habitat assessment, species surveys, avian impact studies, etc.).

Agency	Type of Approval / Review	Proposed Activity
USFWS, Migratory Birds	Migratory Birds Treaty Act/Bald and Golden Eagle Protection Consultation	Required when construction or operation of a proposed facility could impact migratory birds, their nests, and especially threatened or endangered species, including those protected under the Bald and Golden Eagle Protection Act.
State		
Minnesota Department of Natural Resources (MDNR) / Minnesota Department of Health	Preliminary Well Construction Assessment and Approval (MN Rules Ch 4725)	A person may not construct a water-supply, dewatering, or environmental well until a notification of the proposed well on a form prescribed by the commissioner is filed with the commissioner with the filing fee.
MDNR	Water Appropriation	If groundwater pumping from the Proposal exceeds the 10,000-gallon per day or 1,000,000 gallons per year thresholds, a MDNR Water Appropriation Permit will be obtained.
Minnesota Pollution Control Agency (MPCA)	NPDES/SDS Construction Stormwater General Permit and Stormwater Pollution Prevention Plan (SWPPP)	Required for all stormwater discharges from construction activities which will disturb one (1) or more total acres of land.
MPCA	Title V Air Operating Permit	Minn. R. 7007.0200 and Minn. R. 7007.0250 specify the facilities requiring an air emissions permit. Construction of a new source

Agency	Type of Approval / Review	Proposed Activity
		meeting those specifications must receive an air emissions permit prior to commencement of construction. In some cases, Environmental Review (Minn. R. 4410) is required before a permit can be issued. The Proposal would not be subject to major Prevention of Significant Deterioration air permitting.
MDNR	Threatened & Endangered Species Review	Required when a proposed project may impact State-listed species or when a project lies within an area of known occurrence of listed species or the habitat of a listed species.
Minnesota Department of Transportation (MDOT)	Oversize/Overweight Permit	Required whenever oversize/overweight equipment travels on State roadway.
MDOT	Tall Tower Permit	Required for tall, non-transmitting structures located outside the zoned territory of a public use airport with airport zoning in place.
Local		
Lyon County	Oversize / Overweight Permit	Required whenever oversize/overweight equipment travels on roadway or bridges on county roads.
Lyon County	Utility Permit	Required to install and maintain the utilities in township right-of-way

Agency	Type of Approval / Review	Proposed Activity
Custer Township	Road and Highway Access Permit	Required to install access from roads to site.

3. RESOURCE NEED.

3.1 Need for Firm Dispatchable Resources.

The 2019 IRP discussed the need for firm dispatchable resources to meet customer demand,[32] system restoration needs,[33] and our capacity requirements as baseload plants retire and additional renewable generation comes online[34]. With several large thermal baseload units retiring and several smaller firm dispatchable resources reaching the end of their current lives or with expiring contracts in the 2020s our resource plan had identified a need for incremental firm dispatchable capacity.[35] The Commission's IRP Order addressed the need for additional firm dispatchable resources starting in 2027 in Order Point 3:

> 3. In addition to the resources discussed in Ordering Paragraph 2, the Commission finds that it is more likely than not that there will be a need for approximately, but not more than, 800 MW of generic firm dispatchable resources between 2027 and 2029. In a future resource plan, Certificate of Need application, or applicable resource acquisition proceeding, Xcel shall include an evaluation of renewable resources and storage that can deliver the identified necessary grid attributes to meet the need for approximately, but not more than, 800 MW of generic firm dispatchable resources between 2027 and 2029. [36]
>
> * * *
>
> C. Xcel shall analyze this likely need based on up-to-date system-wide modeling, including corrected modeling of wind fleet variability and of exchanges with MISO, in order to–

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[32] Alternate Plan at 9.

[33] Alternate Plan at 54.

[34] Alternate Plan at 30.

[35] Alternate Plan at 114.

[36] IRP Order at 32, ¶ 3.

> 1) establish the capacity, energy, resource adequacy, energy availability, ancillary service, and reliability needs, and
>
> 2) quantify and compare the contribution of the electric system attributes from the different resource options considered to meet the identified grid needs. [37]

While the Commission approved a likely need for up to 800 MW of firm dispatchable resources and initiated this proceeding to identify and select the resources best suited to fulfill the firm dispatchable need, the need must still be analyzed based on up-to-date system-wide modeling.

Generally, we analyze resources as part of our resource planning efforts. While our 2019 Resource Plan was our most recently approved plan, we anticipate filing our 2024-2024 Resource Plan with the Commission in February. Our 2024-2040 Resource Plan will include the necessary up-to-date system-wide modeling required for the proceeding, which we plan to file with in the administrative proceeding.

That being said, we believe our updated modeling will affirm the need for firm dispatchable resources. Given the likely need, the Company believes the prudent approach is to continue to plan to meet the current identified need for our system while vetting the need against the updated modeling.

This conservative approach ensures adequate generating capacity under all reasonable circumstances. At the same time, the Commission can consider options that provide flexibility to adjust the timing of resource additions.

CTs can start up quickly, which allows them to provide power when demand levels are high or increasing rapidly. This quick response time is a significant advantage in maintaining the reliability of the power grid. In addition, combustion turbines provide stability to the voltage support, which is crucial for the smooth operation of the grid.

CTs are a highly effective firm dispatchable resource due to their flexibility, stability and support for renewable energy. As the power grid incorporates more renewable energy sources like wind and solar, which are intermittent, CTs can quickly ramp up to compensate for the intraday and intra-hour variability in renewable resources or fluctuations in electricity demand. Thus, the combination of flexibility, stability, support

[37] IRP Order at 32, ¶ 3(C).

for renewable energy, long-duration storage, and cost-effectiveness makes CTs a valuable firm dispatchable resource in the power grid.

3.2 Minnesota's Carbon Free and Renewable Energy Standards.

In 2005, about 65 percent of electricity generated in Minnesota came from coal and natural gas.[38] In 2023, renewable energy provided the largest share of electricity generation statewide.[39]

State energy policies have also grown and evolved over the years. Minnesota's original Renewable Energy Objective, adopted in 2001, directed all electric utilities in the state to "make a good faith effort" to obtain one percent of their Minnesota retail energy sales from renewable energy resources in 2005, increasing to seven percent by 2010. Minnesota statute also required Xcel Energy to generate 30 percent of its retail sales from renewable energy by 2020.[40] Xcel Energy met that target.[41]

More broadly, Minnesota had previously set a goal to reduce statewide greenhouse gas emissions across all sectors reducing those emissions to a level at least 30 percent below 2005 levels by 2025 and to a level at least 80 percent below 2005 levels by 2050.[42] Similarly, Minnesota has recognized a "vital interest in providing for . . . the development and use of renewable energy resources wherever possible."[43]

Xcel Energy has been working to meet these goals and, more recently, in 2023, Minnesota amended Minn. Stat. § 216B.1691 to include additional milestones for renewable energy, as well as new carbon-free energy standards. The new legislation requires Xcel Energy to generate or procure carbon-free energy equivalent to 100

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[38] U.S. Energy Information Administration (EIA), *Electricity Data Browser* (2023), available at https://www.eia.gov/electricity/data/browser/ (last accessed Jan. 21, 2024).

[39] EIA, *Minnesota State Profile and Energy Estimates* (Oct. 2023), available at https://www.eia.gov/state/?sid=MN (last accessed Jan. 21, 2024).

[40] Minn. Stat. § 216B.1691, subds. 2 and 2a (2021).

[41] *See In the Matter of Commission Consideration and Determination of Compliance with Renewable Energy Standards for Year 2020*, MPUC Docket No. E999/PR-21-12, Renewable Energy Certificate Retirement and Solar Energy Standards Reporting for Compliance Year 2020 (June 2, 2021).

[42] Minn. Stat. § 216H.02, subd. 1 (2012).

[43] Minn. Stat. § 216C.05, subd. 1 (2023).

percent of its Minnesota retail sales by 2040. The law also requires Xcel Energy to achieve interim carbon-free standards of 80 percent by 2030 and 90 percent by 2035, and a renewable energy standard of 55 percent by 2035.

Xcel Energy is committed to delivering carbon-free electricity and is on track to meet Minnesota's 100 percent by 2040 law targets. In December 2018, Xcel Energy was the first major U.S. energy provider to commit to delivering 100 percent carbon-free electricity by 2050, with one of the most aggressive interim targets to reduce carbon emissions more than 80 percent by 2030, from 2005 levels. Xcel Energy has already reduced carbon emissions by 51 percent, and the 2019 IRP surpasses Xcel Energy's interim target, reducing estimated carbon emissions over 85 percent by 2030, with even deeper carbon reductions beyond 2030 that position Xcel Energy well to reach 100 percent carbon-free energy faster, meeting the ambitious new goals of the State of Minnesota.

Like compliance with the renewable energy standard (RES), we will demonstrate compliance with the Carbon Free Standard (CFS) by comparing the total megawatt-hours of carbon-free generation on our system – that is, our five-state Upper Midwest integrated system – to our Minnesota retail sales. Our system's carbon-free generation will be allocated to our Minnesota jurisdiction based on the percentage of total system sales in Minnesota. Currently, approximately 73 percent of our total system sales are to Minnesota customers.

The Company is well positioned to achieve compliance with the new legislation under the Alternate Plan approved in our last IRP.[44] More specifically, the Commission approved Xcel Energy's plan that is expected to reduce carbon dioxide emissions more than 85 percent from 2005 levels and deliver at least 80 percent of customers' electricity from carbon-free energy sources by 2030. Further, as shown in the table below, based on the 2019 IRP Alternate Plan (which represents our currently approved IRP), our system will meet or exceed Minnesota's 100 percent CFS by 2040 law targets.

[44] *See* IRP Order.

Table 3-1: Approved IRP Alternate Plan Carbon-Free Energy[45]

	2030	2035	2040
Carbon-Free Generation (GWh)	42,873	40,044	46,348
Allocation to Minnesota (GWh)	31,187	29,129	33,714
Minnesota Retail Sales (GWh)	30,062	30,702	33,467
Percentage Carbon-Free Generation (Carbon-Free Gen/MN Retail Sales)	100%	95%[46]	100%

As shown in the table above, based on the 2019 IRP Alternate Plan (which represents our currently approved IRP), our system will meet or exceed the thresholds required by the CFS. Therefore, the carbon cost assumptions used in our last IRP resulted in a plan that complies with the CFS for our system. [47] We note that Table 3-1 does not rely on renewable energy credits (RECs) or partial carbon-free energy credits associated with market purchases to demonstrate compliance with the CFS, although it is our understanding that those represent acceptable compliance pathways per the legislation.

We also note that the CFS applies only to energy sales in Minnesota and differs materially in both scope and carbon accounting framework from the Company's goal to achieve a carbon-free generation system across the eight states we serve by 2050. Notably, the legislation preserves opportunities to invest in firm dispatchable units as

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[45] We note that our accounting for compliance with the carbon-free standard matches the annual utility generation or procurement from carbon-free technologies (including the carbon-free portion of market purchases) against annual retail electric sales in Minnesota. Compliance with the carbon-free standards is determined by the delta between carbon-free generation and the total of retail electric sales in Minnesota.

[46] Note that the decline in percentage of carbon-free energy is attributable, in large part, to Prairie Island units rolling off the system, per their current end of license life in 2033/2034.

[47] *See In the Matter of Northern States Power Company, d/b/a Xcel Energy's 2020-2034 Upper Midwest Integrated Resource Plan*, MPUC Docket No. E-002/RP-19-368, Reply Comments by Xcel Energy at Appendix A (June 25, 2021).

Numbers presented in Table 3-1 above are based on the PVRR results where cost of carbon is not considered in the dispatch decisions but has been included in capacity expansion optimization.

needed to ensure system reliability, provided that sufficient quantities of energy generated on a utility's system is carbon-free relative to retail sales.

Xcel Energy anticipates that its forthcoming IRP filing will, likewise, continue to show compliance with the CFS while, at the same time, also continue to demonstrate a need for the firm dispatchable resources to be provided by the Bison Generating Station.

Additionally, Xcel Energy, as part of the Minnesota Transmission Owners, regularly files a Biennial Transmission Report (Biennial Report). Among other things, the Biennial Report includes an analysis of any transmission needed to meet the CFS. The 2023 Biennial Report was filed on November 1, 2023, in MPUC Docket No. 999/M-23-91.

4. PROPOSAL DESCRIPTION.

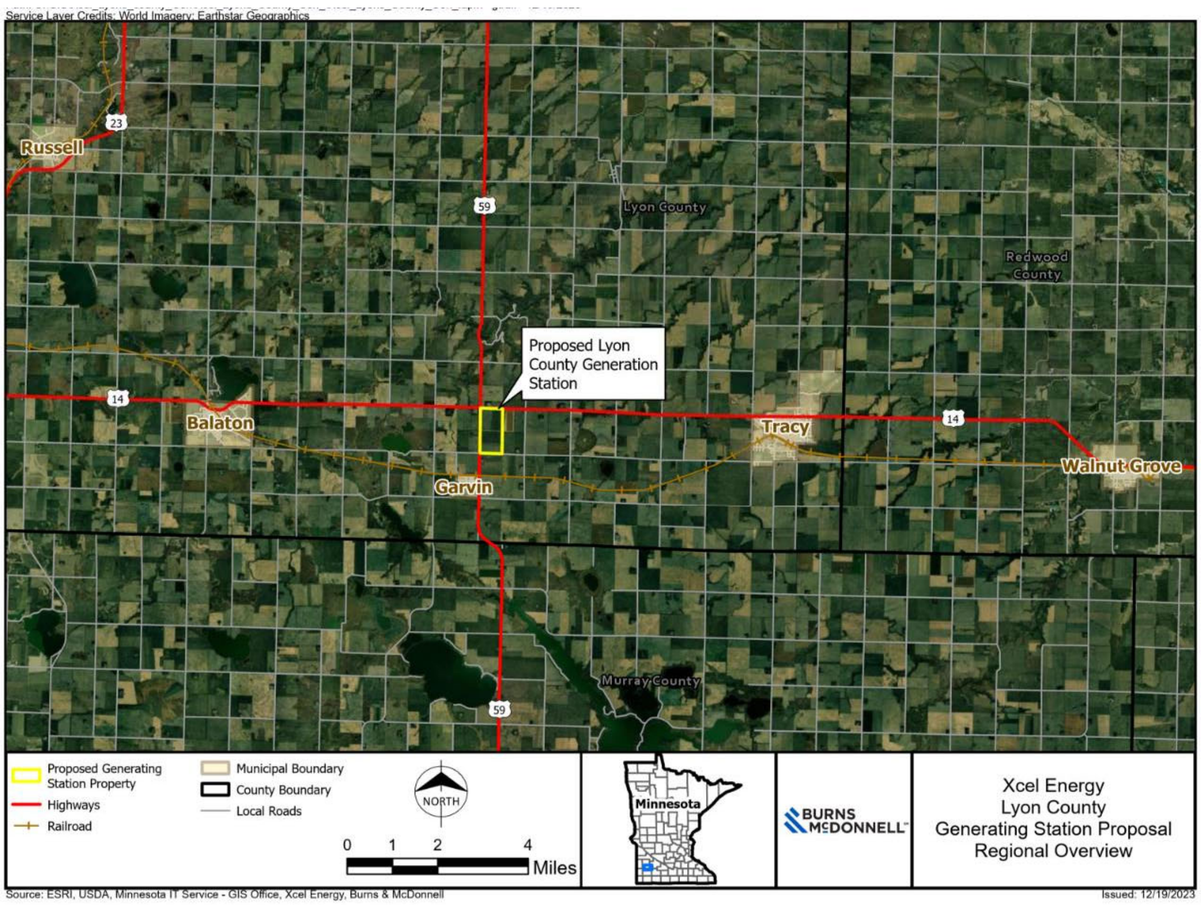
4.1 Proposal Overview.

The Company proposes to install two natural gas-fired, simple-cycle CT generators and auxiliary equipment. Each CT will have the capability to co-combust hydrogen with natural gas. Each CT can produce approximately 210 MW (nominal) of power in summer heat and humidity conditions. Total generating capacity will be approximately 420 MW (nominal). The CTs would be placed in service in 2027 at a greenfield site owned by the Company located approximately one mile north of Garvin, Minnesota, in Lyon County. The site allows the Proposal to interconnect to the MISO transmission system via the proposed MNEC project and will tie into the Northern Border natural gas pipeline, which runs through the southwest corner of the site.

4.1.1 Location and Preliminary Layout.

The Proposal would be located approximately one mile north of Garvin in Lyon County, Minnesota, approximately 17 miles south of Marshall, Minnesota, and 65 miles east of Brookings, South Dakota (see Figure 4-1).

Figure 4-1: Proposed Site



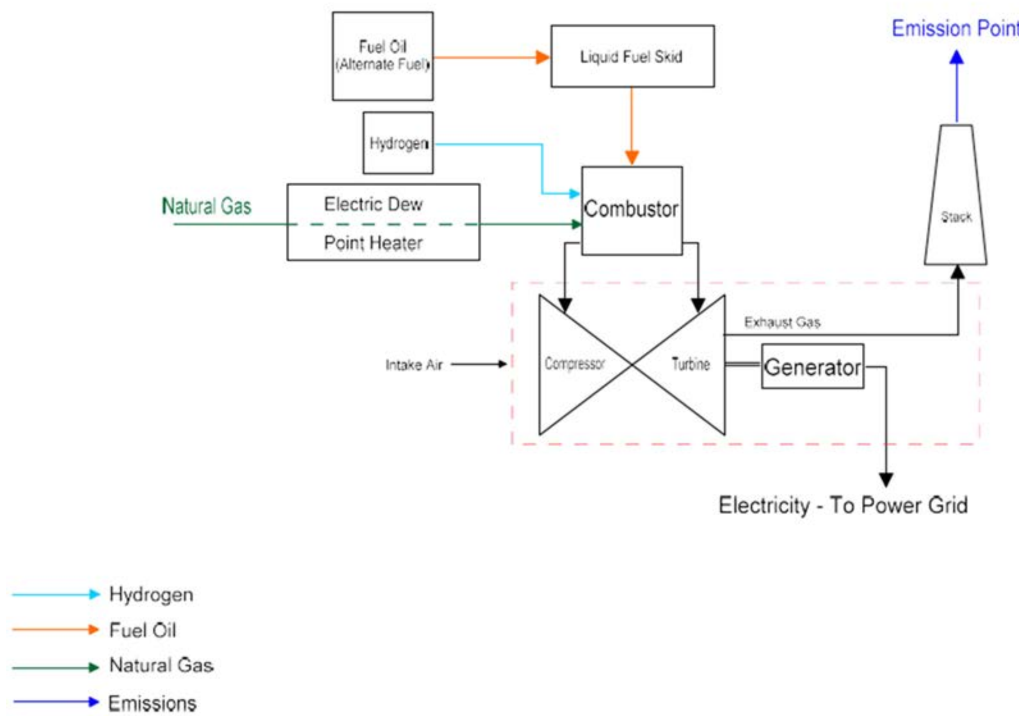
The proposed layout is shown in Figure 4-2. The 345 kV gen-ties would connect the Lyon County Station to the MNEC Terminal Substation

Figure 4-2: Layout

4.1.2 Simple-Cycle Combustion Turbines.

A simple-cycle CT is an electric generating technology in which electricity is produced from a CT without incorporating heat recovery from the turbine exhaust. A schematic of a single CT at Lyon County is shown below in Figure 4-3.

Figure 4-3: Schematic Diagram of a Simple Cycle Combustion Turbine



The design capacity of this Proposal is based on the performance characteristics of F-class CTs. The CT technology available today is significantly improved over that available even a few years ago. The model of F-class CTs now commercially available has fast start capability, which allows it to reach 150 MW in 10 minutes from a cold start, operate in a range of at least 50 to 100 percent load while meeting emission limits, and achieve faster ramp rates over the load range. In addition, the maintenance and overhaul cycles have been significantly improved as compared to earlier F-class CTs. The base performance, with respect to full load capacity and heat rate, has also been improved.

Each combustion turbine-generator consists of the following equipment in series:

1. Inlet Air Filter and evaporative cooler, which cleans and cools the air entering the turbine;

2. Compressor, where air is drawn in and compressed;
3. Combustor, where the air/fuel mixture is ignited;
4. Power Turbine, where the combusted gases expand to rotate a turbine-generator;
5. Generator, which converts the rotating mechanical energy to electrical energy;
6. Main Step-Up transformer, which increases the generator voltage to the transmission voltage of 345kV; and
7. Auxiliary Transformer, which converts some of the output power to lower voltages for use by the Unit's auxiliary equipment.

The CT units will be integrated into the Company's remote dispatch control center. The Lyon County Station is expected to use the units for peaking load service, dispatching them after all lower cost and "must run" units. They are expected to be dispatched primarily during higher system load periods in the summer and winter months, with an annual capacity factor of between five and ten percent, but will be permitted to operate up to 35 percent capacity factor. Currently, modeling shows a 5-10 percent capacity factor; however, future needs may vary with the decommissioning of coal-fired and other older fossil-fuel generation plants, as well as further integration of renewable energy.

The CT units will also serve to load follow as system load requirements change. They will be able to provide capacity of 150 MW within a 10-minute notice (qualifying the units for spinning reserve status within MISO), and will have the ability to ramp at a minimum of 15 MW per minute.

The CTs will include exhaust stacks that will be approximately 90 feet tall. Water supply is anticipated to be via an on-site well. The site will also include three 750 kW emergency diesel generators (for power in case of an emergency).

4.1.3 Associated Transmission Lines.

The Proposal also includes two 345 kV gen-tie lines, one from each CT, that will connect the Lyon County Station to the MNEC Terminal Substation. Xcel Energy anticipates that these lines will be greater than 1,500 feet but located entirely within a 150-foot right-of-way within Xcel Energy property. The proposed conductor is 2-954 ACSS/TW or a conductor of similar capacity. Xcel Energy selected this design and voltage for the gen-tie lines because one gen-tie is needed for each CT, and the proposed design adequately, economically, and reliably supports interconnection of the Lyon County Station as compared to other designs and voltages. Exemplar structures are included in **Appendix C**.

With respect to electric and magnetic fields, the transmission lines associated with the Proposal are anticipated to comply with applicable Commission standards and be consistent with levels from other similar transmission lines.[48] Transmission lines are designed to not cause radio or television interference under typical operating conditions. If interference does occur where good reception is presently obtained, the Company will take necessary action to restore reception to the present level.

Construction of the transmission lines will begin after land acquisition is complete and required permits and approvals are obtained. Construction will follow Xcel Energy's standard construction and mitigation best practices as developed to minimize temporary and permanent impacts to land and the environment. Once construction is completed in an area, disturbed areas will be restored to their original condition to the maximum extent feasible.

Transmission lines are designed to operate for decades and require only moderate maintenance. Xcel Energy will regularly inspect the transmission lines as part of its ongoing maintenance practices. The estimated service life of the transmission lines for accounting purposes varies among utilities. Xcel Energy uses an approximately 60-year service life for its transmission assets. However, practically speaking, high voltage transmission lines are seldom completely retired. The average annual availability of transmission infrastructure is very high, in excess of 99 percent. Given the close proximity of the Lyon County Station to the MNEC Terminal Substation, line losses are anticipated to be negligible.

4.2 <u>Source of Fuel.</u>

The Proposal includes natural gas-fired CTs which would be capable of co-combusting hydrogen. A gas pipeline owned by Northern Border Pipeline Company is located on the southwest corner of the site. The Company will be contracting with Northern Border Pipeline Company to provide gas for the site. Because of the proximity to this pipeline, no on-site natural gas storage will be required.

Additional information related to fuel requirements is provided in Appendix B, Table B-2.

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[48] For additional information about electric and magnetic fields, *see In the Matter of the Application of Xcel Energy for a Certificate of Need for Two Gen-Tie Lines from Sherburne County to Lyon County, Minnesota* MPUC Docket No. E-002/CN-22-131, Application for a Certificate of Need at 82-89 (Mar. 9, 2023) (Minnesota Energy Connection Project CN Application).

4.3 Interconnection.

The Proposal would interconnect via the Terminal Substation being proposed by the Company as part of MNEC. The Proposal would connect to the Terminal Substation via two 345 kV gen tie lines that are anticipated to be located within Xcel Energy property. MNEC is being developed to facilitate the re-use of Xcel Energy's existing interconnection rights at the Sherco Substation to enable additional interconnection of renewable resources. Accordingly, a separate MISO interconnection process with potential responsibility for upgrades will not be required for this Proposal.

4.4 Proposal Operation and Maintenance.

The output of the CTs depends on ambient weather conditions (primarily temperature and humidity), fuel, and altitude. For purposes of this application, nominal generating capacity is considered to be about 210 MW at summer ambient conditions of 88F and relative humidity of 71 percent, with an altitude of 1,540 feet above sea level.

The CTs will be operated and maintained by approximately five staff proposed for the site, and the site would include the necessary infrastructure to accommodate this staff. The service life of the CTs is anticipated to be approximately 40 years. Annual availability will be greater than 95 percent.

The scope and frequency of maintenance work on the CTs will be in accordance with power industry standards and equipment manufacturer recommendations. Estimated service life of the units is in excess of 35 years and is dependent upon the number and type of starts for peaking service.

The frequency of maintenance for major CT components is based on the number of unit start-ups and firing hours, and falls into three categories:

- Combustor inspections typically occur every 900 factored starts or 24,000 firing hours, and require a six-seven day outage;

- Hot gas path inspection and component replacement occurs about every 1,800 factored starts or 48,000 firing hours requiring a 11-13 day outage; and

- Major overhauls are scheduled about every 3,600 factored starts or 96,000 firing hours, and require a 23-25 day outage.

Based on the anticipated capacity factors and an average of six hours of operation per start, the units are anticipated to require major maintenance work every five to 10 years.

The operation and maintenance costs are based on Company experience with similar facilities, as well as industry and manufacturer information.

4.5 Proposal Cost.

The capital cost estimates for the Proposal facilities are presented in **Appendix B**. We have taken care and worked closely with vendors to make our estimates as accurate as possible and have included contingency estimates to reflect uncertainty at this stage in development. We have made considerable effort to try to make the data included in this application comparable to those that may be received from independent power suppliers. We have also provided conservative indicative cost estimates for the anticipated gas pipeline interconnection and the transmission facilities to connect the plant to the MNEC Terminal Substation.

4.6 Proposal Schedule

Table 4-1 below identifies the milestones necessary to meet an in-service date of December 2027:

Table 4-1: Milestone Schedule

Milestone	Estimated Date
Commission decision in this docket	December 2024
Commence Commission permitting proceedings	February 2025
Commission permit(s) issued	January 2026
Start of construction	April 2026
Commercial operation date	December 2027

4.7 Consequences of Delay.

In its 2019 IRP Order, the Commission found that it was "more likely than not" that the Company would require approximately, but not more than, 800 MW of firm dispatchable generation between 2027 and 2029. The Company expects that updated analysis in its 2024-2040 IRP will confirm the need for firm dispatchable resources in this timeframe. A delay in acquisition of sufficient firm dispatchable resources could impact Xcel Energy's ability to reliably serve its customers, particularly during severe winter weather events, which are occurring with increased frequency.

In addition, depending on the length of the delay, Lyon County Station may not be able to provide the required system stability support for MNEC in the timeframe needed to bring renewable generation onto the system via that transmission line. In that case, MNEC would need to instead be equipped with synchronous condensers at the Terminal Substation to support levels of interconnected wind and/or solar energy once levels reach 1,000- 1,600 MW.

5. ALTERNATIVES COMPARISON.

The Xcel-Bid Contested Case, also known as the Track 2 bidding process, is a competitive procedure for acquiring resources that operates in the framework of a Certificate of Need proceeding. One key aspect of the Commission's Certificate of Need rules governing this process is the inclusion of an analysis of alternatives as part of the initial proposal. This means that our proposal must not only detail the chosen project but also consider and analyze the alternative solutions considered in its development. However, unlike a traditional Certificate of Need proceeding, it is important to note that we are not the only participants submitting project proposals in this process. Other applicants are also developing their own fully realized alternatives for Commission consideration. These competing proposals may offer different solutions to the identified need than those we considered in developing our Proposal. While a more comprehensive analysis of alternatives will take place among the projects submitted into this proceeding, we contemplated the following alternatives when developing our Proposal.

5.1 Analytical Framework.

In the 2019 IRP Order, the Commission found that it was "more likely than not" that Xcel Energy would require approximately, but not more than 800 MW of generic firm dispatchable resources between 2027 and 2029. The Commission defined "firm dispatchable" for the purposes of that order as "a resource or combination of resources that is able to provide capacity and energy." The Commission also identified the following other characteristics for a firm dispatchable resource that may be considered:

1) energy availability to meet load for extended durations of energy in the context of the system as a whole,

2) the value from production capabilities during potential system restoration events of unknown duration,

3) environmental impacts,

4) costs, and

5) the ability to foster integration of renewable resources.

The Commission did not specify the type of resource that could meet the likely need for firm dispatchable resources, and the Commission directed Xcel Energy to include "an evaluation of renewable resources and storage that can deliver the identified necessary grid attributes. . . ." Thus, to develop the Company's proposals and to compare those proposals with other types of resources, the Company analyzed a number of different perspectives to provide the Commission with a robust record, including cost data, technical feasibility, and risk. This analysis resulted in the three proposals ultimately submitted by the Company in this docket. The Sherco West BESS was designed and included to comply with the Commission's order to evaluate "renewable resources and storage that can deliver the identified necessary grid attributes." [49]

5.2 No facility alternative.

Because the Commission concluded it was more likely than not that Xcel Energy would need up to 800 MWs of firm dispatchable resources in the 2027-2029 timeframe, Xcel Energy did not consider the alternative of not selecting any resources through this process. The 2019 IRP provides a robust record supporting the need for additional firm dispatchable resources to provide stability and reliability benefits to the system as a whole as the Company continues to incorporate more renewable and emerging technology resources. The Company anticipates filing its 2024-2040 Resource Plan in February this year and believes that its updated modeling will affirm the need for firm dispatchable resources.

5.3 Purchased Power.

We expect that this competitive acquisition process will attract proposals from independent power producers. We expect that other parties may submit offers for long- and short-term power purchase agreements (PPAs) to fill all or some portion of the identified need.

The Proposal compares favorably to long- and short-term PPAs, regardless of fuel source. With respect to a PPA for non-renewable generation, the Lyon County CTs likely compare favorably on an emissions and environmental basis. CT resources can provide significant value to the system for reliability, firm capacity and energy during occasional extended periods of low renewable output – but operating at low annual capacity factors means they will emit much less carbon than a more traditional non-renewable generator. Looking forward, operating in synchronous condenser mode or on hydrogen, means they can provide valuable services for the grid while emitting even less carbon.

[49] IRP Order at 32, ¶ 3.

Likewise, a PPA—regardless of generation type—would not provide the same stability support for MNEC that could be provided by this Proposal due to its location.

While PPAs can be an appropriate choice under some circumstances, utility-owned generation can provide long-term benefits to our customers that would not otherwise be available from PPAs. For example, PPAs are typically effective during only a portion of a project's useful life, and upon expiration the independent supplier is able to sell the facility's output to others or renegotiate terms for a new PPA. New utility-owned resources, on the other hand, will remain available to ratepayers during the project's full useful life, or even longer if the life of the unit is extended, as is often the case. This difference is an important distinction that should be considered when comparing alternatives. Additionally, the utility and Commission will have direct oversight over decommissioning of this asset when it is no longer meeting the needs of Xcel Energy's system.

Further, short-term purchase power agreements (less than 5 years) could also be part of a chosen portfolio, if they are shown to be a cost effective 'bridge' to extending the time period before investment in new generating capacity becomes necessary. However, we do not believe that a portfolio consisting of only short term purchased power is appropriate to fill the entire 800 MW of capacity. If shorter term capacity proposals are offered in the competitive acquisition process, they should be compared to the other proposals to determine which reduce our customers' power supply costs over the long term.

5.4 New Generating Facilities.

5.4.1 Distributed generation.

Pursuant to Minn. Stat. § 216B.2426, we also considered the use of distributed generation to meet the likely need. In Minnesota, distributed generation (DG) is defined generally as generation that is located on or near the site where the output is primarily to be used, interconnected to and operated in parallel with the electric grid, and has a total capacity of no more than 10 MW.[50]

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[50] *In the Matter of Establishing Generic Standards for Utility Tariffs for Interconnection and Operation of Distributed Generation Facilities under Minnesota Laws 2001, Chapter 212*, MPUC Docket No. E-999/CI-01-1023, Order Establishing Standards (Sept. 28, 2004). Minnesota defines renewable projects between 10 and 40 megawatts as "dispersed" renewable generation (DRG). *See* 2007 Minn. Laws, ch. 136, art. 4, sec. 17.

The 2019 IRP record contained a robust discussion and consideration of distributed generation resources. Nonetheless, the Commission agreed that it is more likely than not that the Company will need 800 MWs of firm dispatchable resources by 2027-2029. Importantly, distributed solar resources are a variable resource that cannot meet the need for firm dispatchable resources. Likewise, the Resource Attributes Matrix approved for this docket requires, as a threshold requirement, that proposals be transmission-interconnected, which is generally not the case for much distributed generation.

5.4.2 Renewable energy.

Renewable energy is a vital part of the Company's portfolio, and it will play an increasingly important role in reliably and economically serving customer needs in the coming years. This Proposal and renewable energy are not interchangeable alternatives to each other. Rather, the firm dispatchable generation that would be provided by the Lyon County Station would play a critical role in our clean energy transition by facilitating the additional interconnection and operation of renewable resources.

The firm dispatchable generation provided by the Proposal plays a critical role in replacing the Sherco coal units and serves an important role for system stability. The Lyon County Station can support capacity and energy needs when variable renewables are not available. Yet, these CTs would have relatively low capacity factors – meaning their contribution to carbon is also relatively low. The Lyon County Station would be, in essence, a necessary insurance policy that enables Xcel Energy to pursue deep carbon reduction and higher and higher levels of renewable penetration while ensuring that customers will receive reliable and affordable service during the hottest and coldest days of the year, even when renewable generation is limited or non-existent. Right now, CTs are the most efficient and economical resource to support the energy transition, and we will ensure the assets are hydrogen-ready so we can leverage technology within the lifetime of these assets as we transition to future carbon-free fuels and advanced storage mechanisms.

5.5 <u>Battery Energy Storage.</u>

Like renewable generation, battery energy storage will be a critical component of the Company's portfolio going forward, and Xcel Energy is submitting a proposal for a long-duration lithium-ion battery collocated with the Company's Sherco Solar West Generator as part of this portfolio. However, standalone storage is not a feasible or prudent alternative to this Proposal. Xcel Energy recognizes the system benefits of utilizing storage for certain circumstances such as peak shaving or extending solar generation's capabilities. However, the ability of standalone storage to provide the same attributes as CTs is not yet economically feasible or fully understood in this climate zone. For example, the capabilities of the storage resource most commonly put forward for consideration – conventional lithium-ion batteries – are currently limited to four hours. Four-hour batteries are simply not sufficient to meet our reliability needs in all cases, particularly when needed in substantial amounts for multi-day contiguous periods. For example, on January 30 and 31, 2019 our CT fleet dispatched for a period of 45 contiguous hours – a critical time period during the 2019 polar vortex. As further discussed in the Company's Sherco West BESS Proposal, lithium-ion batteries, which reflect the most well-known and reliable battery technology available today, represent a first of its kind proposal to utilize this technology as a utility scale long-duration resource. And, while technically feasible, scaling lithium-ion batteries to serve as long-duration battery storage, as well as other long-duration battery energy storage, are not yet economically competitive with CT units as a firm, dispatchable resource. Table 5-1 summarizes the factors that make a BESS not a reasonable and feasible alternative to the Proposal.

Table 5-1: Profile of Issues with BESS Alternatives to this Proposal

	Standalone (no co-location with generation asset)	**Hybrid (co-located with generation asset)**
Li-Ion and Other Batteries Designed for Long Duration Capability	Cost prohibitive to build at same size as proposed CT More limited capability to directly integrate renewables Limited commercial deployments No onsite generation – forced to rely exclusively on grid for charging.	May be cost prohibitive to build at same size as proposed CT Limited commercial deployments Operational uncertainty because of evolving MISO Market Participation Models for Hybrid and Co-Located Resources
4-hour Li-Ion Battery Energy Storage (Short Duration)	No onsite generation – forced to rely exclusively on grid for charging. More limited capability to directly integrate renewables Poorest dispatch duration (MISO categorizes these as a	Poorer dispatch duration than proposed CT Operational uncertainty because of evolving MISO Market Participation Models for Hybrid and Co-Located Resources

	Standalone (no co-location with generation asset)	Hybrid (co-located with generation asset)
	different Capacity Resource type than CTs: Use Limited Resource) Affected more acutely by operational temperature limitations than other alternatives	

5.6 Demand Side Management.

The Company's Demand Side Management (DSM) programs (including energy efficiency and demand response) are discussed in Appendix A and are the subject of thorough analysis in various regulatory proceedings, including the IRP process. The Company is committed to growing and implementing DSM programs, as shown in our 2024-2026 ECO Triennial Plan (Docket No. E,G002/CIP-23-92). While these programs are robust, they cannot replace a large firm dispatchable generation plant, as identified in the 2019 IRP. Additionally, given that this acquisition seeks 800 MW of resources coming online between 2027 and 2029, it is extremely unlikely that an equivalent amount of incremental DSM programs could be cost-effectively attained within this time frame. The 2019 IRP includes incremental DSM, and Xcel Energy nonetheless demonstrated that up to 800 MW of firm dispatchable resources would likely be needed to provide system stability and reliability.

5.7 Other Alternatives.

New transmission is not an alternative to the Proposal because it does not provide energy and capacity. The Company also evaluated increasing efficiency at existing facilities as an alternative; however, at this time, Xcel Energy has not identified any cost-effective efficiency opportunities within its existing generation fleet. Likewise, the Company is not aware of any innovative energy project, as defined by Minn. Stat. § 216B.1694, available to meet the likely need. Given that none of the alternatives above represents a reasonable alternative to the Proposal, a combination of these alternatives also does not present an opportunity to meet the identified need for firm dispatchable resources provided by the Proposal.

5.8 Conclusion.

Pursuant to Minn. Stat. §§ 216B.2422, subd. 4, and 216B.243, subd. 3a, Xcel Energy's analysis has shown that the Proposal is less expensive than a project generating renewable energy and/or otherwise in the public interest because it provides a reliable and economical firm dispatchable resource that has been developed to minimize impacts, make use of existing infrastructure, and can be implemented to further support the integration of renewable energy resources on Xcel Energy's system.

6. ENVIRONMENTAL INFORMATION.

6.1 Affected Environment & Environmental Setting.

Xcel Energy proposes to locate the Lyon County Generating Station directly adjacent to the Terminal Substation proposed as part of MNEC. The Lyon County Generating Station would occupy approximately 40 acres of land currently in agricultural production. The Lyon County Generating Station would interconnect to the MISO grid via MNEC, the environmental impacts of which were described in its route permit application and will be the subject of an environmental impact statement in Docket 22-132.

6.2 Human Settlement.

6.2.1 Displacement.

There are no residences within 500 feet of the footprint of the Lyon County Generating Station. The closest residence is approximately 875 feet south of the edge of the facility footprint. Therefore, no residences would be displaced by the Proposal.

6.2.2 Noise.

The Proposal will be designed to meet the applicable noise requirements. The State of Minnesota regulates noise under the Minn. R. 7030.0040, which defines applicable noise limits based on noise area classification (NAC). Subpart 2 of Minn. R. 7030.0040 provides the following numeric noise standards:

Table 6-1: MPCA Noise Standards

Noise Area Classification	Daytime L50 (dBA)	Daytime L10 (dBA)	Nighttime L50 (dBA)	Nighttime L10 (dBA)
1 (Residential)	60	65	50	55
2 (Commercial)	65	70	65	70
3 (Industrial)	75	80	75	80

Based on the Minnesota noise standards, noise from the Proposal should be limited to 50 dBA at the nearest residential property, consistent with the nighttime L50 limit for the residential NAC.

The Proposal will include mitigation measures to ensure the State of Minnesota limits are met. These measures include, but are not limited to, the following:

1. Exhaust stack acoustic silencers on simple-cycle CT exhausts

2. Intake silencers on simple-cycle CT air inlets

3. Low-noise equipment specifications for major heating, ventilation, and air conditioning (HVAC) equipment

Any additional noise from the associated transmission lines would be negligible.

Temporary noise would also be generated by the construction of the Lyon County Station. Construction noise is predominantly generated from intermittent sources including diesel engine driven construction equipment and pile driving, if required. Potential noise impacts would be mitigated by proper muffling equipment fitted to construction equipment and staggering construction activities to minimize impacts. Construction noise may be audible at times at the nearest residential receptors. However, construction noise would be temporary and intermittent.

6.2.3 Traffic and Transportation Infrastructure.

The existing traffic volume on nearby roads is documented in Table 6-2. Determining the specific capacity of any highway is a complex process; however, general estimates are used for planning purposes. For purposes of comparison, the functional capacity of Annual Average Daily Traffic (AADT) of some of the nearby roads is detailed in Table 6-2.

Table 6-2: Existing Daily Traffic Levels

Roadway	Roadway Segment	Year	AADT
US Highway 14	East of US 59	2022	2,080
US Highway 14	West of US 59	2023	1,354
US Highway 59	North of US 14	2022	2,597
US Highway 59	South of CSAH 14 (110th St), East of Garvin	2021	6,014
280th Ave	North f US 14	2022	50

*Annual Average Daily Traffic
Source: Minnesota Department of Transportation (MnDOT) Traffic Mapping Application

The equipment and material deliveries generated by construction are estimated to be approximately 900 truckloads over the approximately 18-month period of construction. Deliveries and workers could use any combination of federal, state, and county highways and other township roads throughout the Proposal area. All necessary provisions would be made to conform to safety requirements for maintaining the flow of public traffic.

Truck access to the site would be served by 120th Street. Construction of the Lyon County Station could result in temporary traffic delays on this road as a result of wide-load or other construction traffic accessing the site. Additional operating permits would be issued by the state, county, and/or township for over-sized truck movements.

During operation of the Lyon County Station, the workforce and support services would generate an approximate maximum of 10 additional vehicle trips per day. No impacts to area roads would occur from operation.

Construction and operation of the Proposal would be in accordance with applicable federal, state, and local permits and laws, as well as industry construction and operation standards. The Company would coordinate with MDOT to obtain over height/overweight permits as necessary prior to transporting equipment. Appropriate notification to the FAA would be provided for construction cranes, turbine stacks, and any communications facilities.

Although some facility components may be transported by rail, the Proposal is not anticipated to result in appreciable changes in rail or barge traffic.

6.3 Archaeological and Historic Resources.

Xcel Energy reviewed cultural resource data from the Minnesota State Historic Preservation Office (SHPO) as part of MNEC for the area. According to the SHPO data, there are no cultural/archaeological resources at or near the Proposal Site.

6.4 Vegetation and Wildlife.

6.4.1 Wildlife.

Wildlife commonly found near the site includes a variety of small to medium sized mammals, reptiles and amphibians, birds, and fish. The largest mammal typically found in the area is the white-tailed deer. Other mammals include coyotes, fox, raccoons, beaver, opossum, woodchucks, squirrels, and muskrats. Reptiles near the Lyon County Station likely include Snapping turtles, Map turtles, Softshell turtles, Painted turtles, gopher snakes, fox snakes, and northern water snakes. Amphibians include leopard frogs, pickerel frogs, spring peeper, and American toads. Fish species vary depending on the type of water body. The most commonly distributed fish species in the area include largemouth bass, sunfish, crappies, northern pike, and multiple species of rough fish such as carp and suckers. Bird species include eagles, turkeys, hawks, pheasants, ducks, herons, and multiple species of song birds.

Because the Proposal is located within a previously disturbed agricultural area, the fauna generally present are adapted to anthropogenic disturbance, and it is unlikely that the construction, operation, and maintenance would have an effect on fauna present in the area.

6.4.2 Wetlands & Waterbodies.

The Lyon County Station is proposed to be sited in cultivated land. A desktop review of wetlands and waterbodies was conducted. Small wetland features occur northeast of the site outside the footprint of the Proposal based on this review. The facility will be sited to avoid wetlands to the extent practicable.

According to the Federal Emergency Management Agency (FEMA) database, the Proposal is in an area of minimal flood hazard (Panels 27083C0575D and 27083C0600D, effective date 11/26/2010).

A new groundwater well will supply the Lyon County Station with water for use onsite. Wastewater discharges would either be directed to the plant absorption basin or a leach field.

Xcel Energy will design the Proposal scope to minimize to the greatest extent possible direct and indirect impacts on waterbodies (e.g., erosion runoff). The Company will apply erosion control measures such as using silt fencing to minimize impacts to adjacent water resources. During construction, Xcel Energy will control operations to minimize and prevent material discharge to surface waters. Disturbed surface soils will be stabilized at the completion of the construction process to minimize the potential for subsequent effects on surface water quality.

Xcel Energy is currently determining specific engineering details for the facility site. Facilities are not expected to be sited within wetlands and/or waterbodies. However, if dredge and fill activities became necessary within jurisdictional wetlands and/or waterbodies, Xcel Energy would obtain approvals from the USACE and/or the MDNR and Minnesota Board of Water & Soil Resources, if necessary, under Sections 401 and 404 of the Clean Water Act and Wetland Conservation Act.

6.4.3 Vegetation Cover.

The Proposal Site is currently a cultivated agricultural field.

6.4.4 Threatened and Endangered Species.

The Proposal Site was assessed for the potential presence of protected species. Resources used included USFWS Information for Planning and Consultation (IPaC) website, MDNR threatened and endangered species lists, and National Agriculture Imagery Program (NAIP) aerial photography.

The site has the potential to contain habitat for monarch butterfly (candidate for federal listing) in vegetated roadside ditches along the southern and western boundaries of the parcel. Loggerhead shrike and Henslow's sparrows (both state endangered) may use agricultural fields and maintained grass areas within the site.

No potential habitat is present within the Proposal Site for the following species based on the desktop review: bald and golden eagles, listed bat species, insects, plants, burrowing owl, king rails, and elktoe mussel.

U.S. Fish and Wildlife Service

The USFWS IPaC website was reviewed for a list of species covered under the Endangered Species Act (ESA) that may be present within the site. According to the website, three federally listed species have the potential to occur in the site (monarch butterfly [candidate species], northern long-eared bat (NLEB) [endangered], and tricolored bat [proposed endangered]). No critical habitat is located at the Proposal Site.

State of Minnesota

The MDNR Rare Species Guide search was utilized to obtain a list of species protected by the state of Minnesota. According to the search, a total of 12 species listed as state threatened or state endangered have the potential to occur within Lyon County.

Threatened and Endangered Species Mitigation Measures

Impacts on individual NLEBs and tricolored bats may occur if clearing or construction takes place when the species are breeding, foraging, or raising pups in its summer habitat. Xcel Energy would implement tree clearing activities in accordance with USFWS regulations and guidance, to the extent applicable.

No in-stream work will be required to construct the Lyon County Station. Xcel Energy will implement appropriate best management practices (BMPs) to prevent erosion and sediment runoff and protect water quality, such as silt fence, straw bale, and other erosion control device installation as outlined in the applicable SWPPP. As such, adverse impacts to the elktoe mussel species are not anticipated.

Adult monarch butterflies feed on nectar from a wide variety of flowers. Reproduction is dependent on the presence of milkweed, the sole food source for larvae. Loggerhead shrike and Henslow's sparrows may use agricultural fields and maintained grass areas within the site. As discussed above, the Proposal was designed to occur primarily in cultivated cropland. The Proposal will also avoid woodlands, shrublands, grasslands, and water resources. However, it is possible that the Proposal will have minor, temporary impacts to native vegetation serving as a food source to monarch butterflies and habitat for avian species; however, no long-term significant impacts to the species are anticipated, particularly given that the Proposal Site is generally a cultivated agricultural field.

6.5 Water Needs.

The Lyon County Station would require water for the CTs. The advantage of simple cycle technology is that it can operate without using significant quantities of water. It is estimated that over 80 percent of the time the CTs operate, no water will be used. Up to 20 percent of the time it is anticipated that evaporative cooling will be used to cool the inlet air of the CTs. This enhances operational efficiency of the units during the warmest days of the year. Evaporative cooling increases the humidity, which results in the cooling of the air entering the combustion turbine. The evaporative cooling process consumes a small amount of water, but increases output by about 5 to 10 percent, depending on the relative humidity during hot summer day operation. The CTs are expected to utilize small amounts of water for evaporative cooling, up to 157,440 gallons per day averaged over the whole year. The gas turbines will perform washdowns approximately 2 times per year utilizing only around 11 gallons per day averaged over the whole year.

Groundwater from new site wells will supply evaporative cooling water and other water needs for the CTs. A well permit will be required from the Minnesota Department of Health per MN Rules Ch 4725 and a preliminary well construction assessment will be conducted for MDNR. Groundwater appropriations permitting with MDNR would be required. Lacking groundwater sufficient to supply plant needs, water would be trucked in or obtained from another source and stored on-site.

6.6 Waste Generation.

Wastewater generation estimates of discharges to water and solid wastes associated with operation of the Lyon County Station are provided in Table 6-3. All waste management activities will be conducted in accordance with applicable rules, regulations, and permits.

Sanitary wastewater will be discharged to an onsite septic system. Other liquid wastes will stem from routine maintenance activities. No radioactive releases will occur as a result of the Proposal.

On-site water storage will include a new tank for storage of treated water for evaporative cooling and other processes. No solid waste will be permanently stored on site. Temporary storage of minor quantities of oily and greasy rags, material packaging, office waste, domestic-type solid wastes, industrial wastes, universal wastes, and hazardous waste will occur during the operation of the facility. As is the case with other similar facilities, the Proposal is expected to be a very small quantity generator (VSQG) of hazardous waste.

Table 6-3: Proposed Lyon County Site Liquid and Solid Wastes

Waste	Phase	Description	Generation Rate	Disposition Method
7849.0320F	Potential Sources and types of discharges to water attributable to operation of the facility			
Service Water	Liquid	Equipment wash water	<1 MGPY	Discharge to plant absorption basin or leach field
7849.0320G.2 Radioactive Releases		None – natural gas combustion		
7849.0320H	Potential types and quantities of solid wastes in tons per year at expected capacity factor			
Maintenance Materials	Solid	Lubricants, hydraulic fluid, etc.	<10 barrels/yr	Manage used oil with a contract firm
Maintenance Materials	Solid	Oily and greasy rags, materials packaging, office waste, domestic-type solid wastes, cleaning solvents.	<5 tons/yr	Dispose of properly as specially regulated, solid or hazardous waste and/or recycle as feasible and allowable
Absorption Basin Solids	Solid	Maintenance cleaning of solids	~0 tons/year	Dispose of properly as specially regulated or solid waste

Solid waste produced will only occur from construction debris, waste produced by construction workers, and wastes produced by employees onsite during operations. This waste will be collected in trash containers throughout the Proposal Site and sent to a local landfill.

All waste management activities will be conducted in accordance with applicable rules and regulations. Site domestic wastewater will be discharged to an on-site drain field.

6.7 Air Impacts.

6.7.1 Generation Air Emissions.

Natural gas-fired combustion turbine technology is among the cleanest means of generating utility-scale electricity. Natural gas combustion generates significantly less carbon dioxide, particulate matter, sulfur dioxide, and hazardous air pollutant emissions (including mercury) than oil or coal. The two combustion turbines are currently capable of co-combusting natural gas with hydrogen. To support the operations at the site, three 750-kw emergency diesel generators will also be installed at the site to support facility power in an emergency.

The primary constituents of concern resulting from combustion of natural gas and fuel oil are oxides of nitrogen (NO_x), carbon monoxide (CO), and volatile organic compounds (VOCs) and particulate matter (PM, PM10, PM2.5). Operation of one of the combustion turbines on fuel oil will be minimal and have limited hours. Our Proposal will control NO_x emissions through use of dry low-NO_x burners in the combustion turbines. Good combustion practices will be used to control emissions of fine particulates, CO, and VOCs. The CTs will be permitted for approximately 35 percent annual capacity.

An air emissions permit application will be submitted in 2024 for the Proposal. The emissions estimate from the units described above were calculated and compared to the Prevention of Significant Deterioration (PSD) threshold of 250 tons per year for each pollutant. Table 6-4 presents the estimated air emissions from the Proposal.

Table 6-4: Estimated Combustion Turbine Air Emissions for Lyon County Station

EPA Criteria Pollutants		
Pollutant	Emission Rate at Rated Capacity, Each Turbine, Natural Gas (maximum at baseload) (lb/hr)	Emissions at Projected Annual Operating Hours, Each Turbine (tons/year)
SO2	5.2	9.4
NOx	71.9	120.8
PM10	6.9	15.3
PM2.5	6.9	15.3
CO	34.0	100.6
VOC	3.3	11.7
USEPA Hazardous Air Pollutants		
1,3-Butadiene	9.53E-04	1.59E-03
1,4 Dichlorobenzene	--	--
Acetaldehyde	8.87E-02	1.48E-01
Acrolein	1.42E-02	2.36E-02
Arsenic		--
Benzene	2.66E-02	4.43E-02
Beryllium	--	--
Cadmium	--	--
Chromium	--	--

Cobalt	--	--
Ethylbenzene	7.10E-02	1.18E-01
Formaldehyde	1.57E+00	2.62E+00
Lead	--	--
Manganese	--	--
Mercury	--	--
Naphthalene	2.88E-03	4.80E-03
Nickel	--	--
Polycyclic Aromatic Hydrocarbons	4.88E-03	8.12E-03
Propylene Oxide	--	--
Selenium	--	0.00E+00
Toluene	2.88E-01	4.80E-01
Xylenes	1.42E-01	2.36E-01

Note: Total Annual emissions are based on worst-case annual emissions. Emissions also represent that worst-case emissions of natural gas or natural gas plus 30% H2.

The Lyon County Station would be capable of rapid starts to support the rapid changes in wind generation. An air emissions permit application is planned to be submitted in 2024. Based on the emissions detailed above, it is expected that the facility will not trigger PSD since no pollutants exceed the PSD major source threshold. Table 6.5 displays the expected total facility maximum permitted annual emissions compared to the PSD thresholds.

Table 6-5: Maximum Estimated Annal Air Emissions for Lyon County Generating Station

Pollutant	Two Combustion Turbines[a] (Tons per Year)	Emergency Generators (Tons per Year)	Potential Emissions (Tons per Year)	PSD Major Source Thresholds (Tons per Year)
NO_X	241.7	7.94	249.6	250
CO	201.1	4.34	205.4	250
SO_2	18.7	0.86	19.6	250
VOC	23.3	1.05	24.4	250
PM	30.5	0.25	30.8	250
PM_{10}	30.5	0.25	30.8	250

Pollutant	Two Combustion Turbines[a] (Tons per Year)	Emergency Generators (Tons per Year)	Potential Emissions (Tons per Year)	PSD Major Source Thresholds (Tons per Year)
$PM_{2.5}$	30.5	0.25	30.8	250
CO_2e	1,040,966	1,21	1,042,26	--

(a)Based on 3,329 hours per year operation for each CT, including startup/shutdown and low load operation in one turbine. Includes worst-case emissions for natural gas or the co-combustion of H2 with natural gas.

With respect to the associated 345 kV gen-tie lines, ozone created by the lines would be minimal and would be well below state and national standards.

The Company anticipates it will be able to obtain appropriate permits and approvals for emissions for the Lyon County Station, as proposed in this Application, and that approvals will be able to be maintained for the life of this Proposal. Environmental regulations continue to be promulgated year after year that could affect this facility; however, Xcel Energy will comply with these regulations if and when they are finalized. Currently, USEPA has proposed a greenhouse gas regulation for new power plants (New Source Performance Standard, Subpart TTTTa), which would limit operations of this facility to 20 percent capacity factor or for the facility to meet lower GHG emissions, which can be met with the 30 percent co-combustion of hydrogen. Therefore, Xcel Energy has analyzed environmental costs and regulations over the expected useful life of the Lyon County Station, and the facility will be able to comply with the only proposed regulation known at this time.

6.7.2 Fugitive Dust.

Site preparation and construction activities to include construction of the CTs, emergency equipment, and transmission lines will produce small amounts of fugitive dust from earth-moving and construction. Fugitive emissions from earth-moving and construction will be controlled on both sites by watering or applying dust suppressants to exposed soil surfaces as necessary. Adverse impacts to the surrounding environment will be minimal because of the short and intermittent nature of the overall emissions and dust-producing earth-moving, construction, and right-of way clearing processes.

Fugitive dust emissions will not be generated in any significant amounts during operation of the plant and are reduced by primarily burning natural gas as a clean burning fuel. Adverse impacts to the surrounding environment will be minimal because of the short and intermittent nature of the emission and dust-producing construction phases.

6.8 Greenhouse Gas, Climate Change, and Climate Resilience.

The Commission ordered that proposals must include a "climate change analysis of the proposal consistent with the Minnesota Environmental Quality Board's [(EQB]) environmental assessment worksheet [(EAW)] guidance for developing a carbon footprint and incorporating climate adaptation and resilience." The following subsections thus provide information responsive to information required in the EQB's EAW.

6.8.1 Greenhouse Gas Emissions (GHG) / Carbon Footprint.

6.8.1.1 GHG Quantification.

Item 18(a) of the EQB's EAW requires project proponents to "provide quantification and discussion of project GHG emissions" and provides example tables to guide that analysis, directing proponents to add additional rows in the tables if necessary "to provide project-specific emission sources." Proponents must describe quantification methods and, if quantification methods are not readily available, describe the process used to come to that conclusion and any GHG emission sources not included in the total calculation.

Construction emissions were calculated using USEPA Motor Vehicle Emission Simulator (MOVES). MOVES generated emission factors for the mobile construction equipment based on the year construction is planned to commence (2026).

Table 1 from USEPA's Revised 2023 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions Standards was used to determine emission factors for gasoline light-duty trucks.[51] A combustion ratio from Table 2 of EPA's Emission Factors for Greenhouse Gas Inventories was used to determine GHG emissions from diesel heavy-duty trucks.[52]

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[51] Revised 2023 and Later Model Year Light-Duty Vehicle Greenhouse Gas Emissions Standards, 40 C.F.R. §§ 86 & 600 (2022).

[52] *Emission Factors for Greenhouse Gas Inventories*, U.S. EPA CENTER FOR CLIMATE LEADERSHIP (Sept. 12, 2023), available at https://www.epa.gov/system/files/documents/2023-03/ghg_emission_factors_hub.pdf (last accessed Jan. 21, 2024).

GHG emissions associated with land use were calculated using the provided equations in the EQB EAW Guidance and Chapter 6 of USEPA's Inventory of Sources and Sinks of Greenhouse Gases.[53]

Operational emissions were calculated using vendor data and 40 Code of Federal Regulations (CFR) Part 98 Subpart C. For the combustion turbine, solely vendor data was used to calculate GHG emissions. Vendor data was also used to calculate GHG emissions from the sulfur hexafluoride (SF_6) circuit breakers.

In Scope 1 of the operational emissions, under combustion stationary equipment, GHG emissions from the two combustion turbines are reported. Under non-combustion stationary equipment, GHG emissions from the SF_6 circuit breakers are reported. There are no Scope 2 emissions to report from the operation of the Proposal as off-site electricity and off-site steam production are not required for operation.

6.8.1.1.1 Construction GHG Emissions.

Table 6-6: Construction GHG Emissions

Scope	Type of Emission	Emission Sub-type	Proposal-related CO2e Emissions (tons/year)	Calculation method(s)
Scope 1	Combustion	Mobile Equipment	5,488	USEPA MOVES4.0, other guidance mentioned above
Scope 1	Land Use	Conversion	13,975	EQB EAW Guidance, EPA's Inventory of Sources and Sinks of GHGs
Scope 1	Land Use	Carbon Sink	N/A	N/A
TOTAL			19,463	

[53] *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2021*, U.S. Environmental Protection Agency, EPA 430-R-23-002 (April 13, 2023), available at https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks-1990-2021 (last accessed Jan. 21, 2024).

6.8.1.1.2 Operational GHG Emissions.

Table 6-7: Operational GHG Emissions

Scope	Type of Emission	Emission Sub-type	Existing facility CO2e Emissions (tons/year)	Proposal-related CO2e Emissions (tons/year)	Total CO2e Emissions (tons/year)	Calculation method(s)
Scope 1	Combustion	Mobile Equipment	N/A	N/A	N/A	N/A
Scope 1	Combustion	Stationary Equipment	N/A	1,042,257	1,042,257	Vendor data, 40 CFR 98 Subpart C
Scope 1	Combustion	Area	N/A	N/A	N/A	N/A
Scope 1	Non-Combustion	Stationary Equipment	N/A	29	29	Vendor data
Scope 1	Land Use	Carbon Sink	N/A	N/A	N/A	N/A
Scope 2	Off-site Electricity	Grid-based	N/A	N/A	N/A	N/A
Scope 2	Off-site Steam Production	Not applicable	N/A	N/A	N/A	N/A
Scope 3	Off-site Waste Managemen t	Area	N/A	N/A	N/A	N/A
TOTAL				1,042,285	1,042,285	

(a) Emissions assume worst-case CO2e emissions from natural gas combustion. Emissions will be less if co-combusting hydrogen.

6.8.1.2 GHG Assessment.

Item 18(b) of the EQB's EAW requires project proponents to provide the following analyses:

6.8.1.2.1 Describe any mitigation considered to reduce the project's GHG emissions.

The Proposal will mitigate GHG emissions from construction and operation of the facility. Where possible, construction equipment will utilize lower GHG-emitting fuels, such as low sulfur diesel and gasoline. Additionally, equipment will not idle unnecessarily during construction, thereby reducing emissions during construction.

The CTs are proposed to combust natural gas. Natural gas has lower CO_2 emissions than coal or diesel fuel (120 lb/MMBtu vs. 160 lb/MMBtu); therefore, the Lyon County Station will emit less GHG than other generating units that are combusting diesel or coal. Further, the CTs proposed here will be capable of co-combusting hydrogen. Initially, the turbines will be permitted to allow for up to 30 percent by weight co-combustion of hydrogen with natural gas. As additional data and testing on the turbines while combusting hydrogen continues, the turbines may combust higher percentages of hydrogen throughout their lifetime. Because hydrogen has no carbon, as opposed to fossil fuels, emissions of GHGs are much lower than that of diesel or natural gas combustion.

6.8.1.2.2 <u>Describe and quantify reductions from selected mitigation, if proposed to reduce the project's GHG emissions. Explain why the selected mitigation was preferred.</u>

Mitigation for GHG emissions from the Proposal includes the ability of the CTs to co-combust hydrogen. At 30 percent by volume co-combustion of hydrogen, the emissions of CO_2 are lowered on an hourly basis (based on the maximum, worst-case CO_2 emission rate from 269,673 lb/hr down to 229,542 lb/hr.). This mitigation option has been proposed by the EPA to reduce GHG emissions in the New Source Performance Standard Subpart TTTTa for GHG emissions from electrical generating units (this regulation is proposed to be finalized in 2024 and the final rule requirements are unknown at this time).

6.8.1.2.3 <u>Quantify the proposed project's predicted net lifetime GHG emissions (total tons/#of years) and how those predicted emissions may affect achievement of the Minnesota Next Generation Energy Act goals and/or other more stringent state or local GHG reduction goals.</u>

The State of Minnesota has several goals to reduce GHG emissions. The Minnesota Next Generation Energy Act aims for net-zero GHG emissions in the state by 2050. This is consistent with the United States's pledge to achieve net-zero GHG emissions by 2050.

The capability of the CTs to co-combust natural gas and hydrogen will allow Minnesota to achieve goals set in the Minnesota Next Generation Energy Act by reducing the

GHG emissions from the Proposal as hydrogen co-combustion is used over solely natural gas combustion. Additionally, these more efficient, lower GHG-emitting generation units will displace the operation of older, less efficient and higher-GHG emitting generation units in Xcel Energy's system. Over time, these new turbines will allow for more renewable energy sources to operate which will displace coal and other less-efficient natural gas and diesel generation units. These new units will cover peak demands when the renewables cannot handle the demand.

6.8.2 Climate Adaptation and Resilience.

The following subsections are responsive to Item 7 of the EQB's EAW regarding climate adaptation and resilience.

6.8.2.1 Describe the climate trends in the general location of the project and how climate change is anticipated to affect that location during the life of the project.

Climate trends for the state of Minnesota show warmer and wetter seasons, with cold weather warming and more damaging rains. Predicted changes for Minnesota include an increased risk of heat wave and drought.

Historical data for Lyon County is concurrent with the climate trends for the state of Minnesota. Using MDNR's Minnesota Climate Explorer, graphs of the historical data were made with trend lines. As seen in Figure 6-1, the average annual temperature since 1895 has increased 0.16 degrees Fahrenheit (°F) per decade. In 6-2, the average annual precipitation is shown, with the trend line determining that the average annual precipitation since 1895 has increased 0.37 inches (in) per decade.

Figure 6-1: Historical Annual Average Temperature in Lyon County (1895-2023)

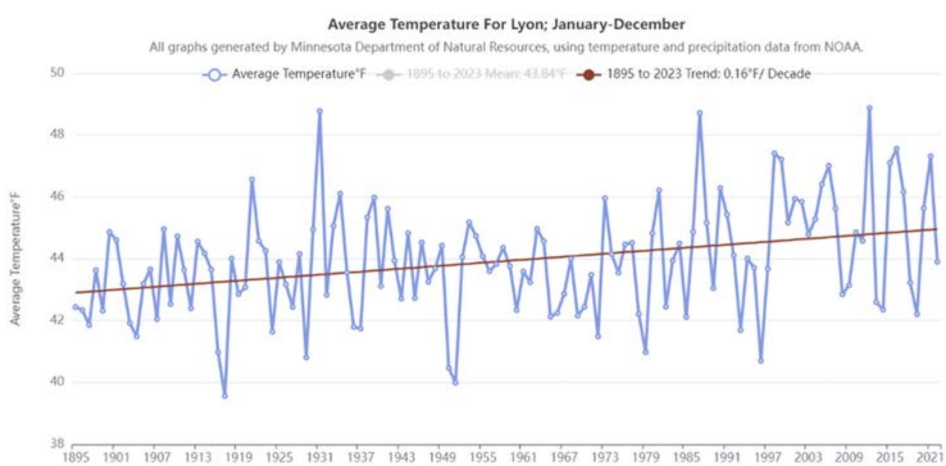
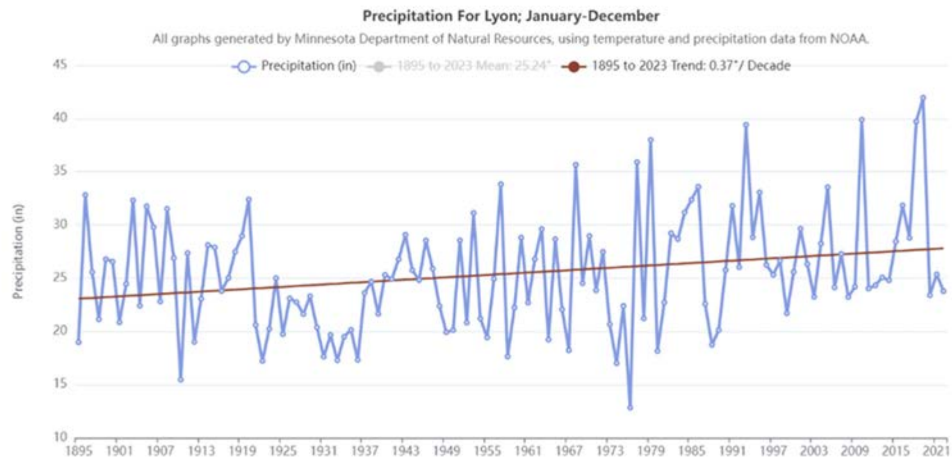
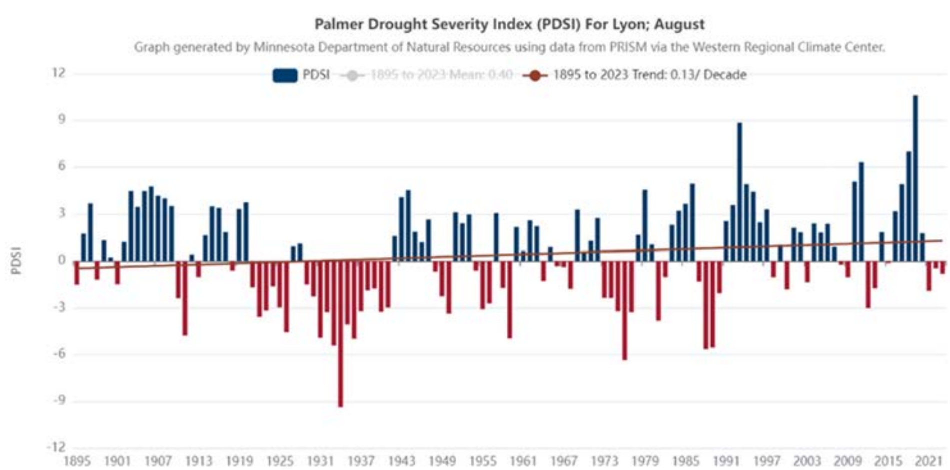


Figure 6-2: Historical Annual Average Precipitation in Lyon County (1895-2023)



The Palmer Drought Severity Index (PDSI) is a tool used to determine drought conditions based on surface air temperature and a physical water balance model which takes into account potential evapotranspiration and the effect of global warming. The index ranges from -10 (dry) to +10 (wet). Figure 6-3 below shows the PDSI for the month of August from 1985 to 2023 for Lyon County. The trend line on the figure shows an increase of 0.13 per decade.

Figure 6-3: Historical PDSI Values for Lyon County (1895-2023)



Also using MDNR's Minnesota Climate Explorer tool, future predictions of average temperature and average precipitation were able to be made for Lyon County. These predictions were made using assumptions from the Intergovernmental Panel on Climate Change (IPCC) and their Representative Concentration Pathways (RCP) RCP 4.5 and RCP 8.5. RCPs represent different greenhouse gas concentration scenarios used by the IPCC in their Fifth Assessment Report (2014). RCP 4.5 is an intermediate scenario while RCP 8.5 is a scenario with high greenhouse gas emissions.

In Figure 6-4, projected average temperatures for Lyon County are modeled. The mean model temperature for the present day (1980-1999) was 44.88°F. For the RCP 4.5 scenario for mid-century (2040-2059), the mean model predicted the average temperature to be 48.26°F. For the RCP 4.5 scenario for late century (2080-2099), the mean model predicted the average temperature to be 50.63°F. For the RCP 8.5 scenario for late century (2080-2099), the mean model predicted the average temperature to be 54.48°F.

Figure 6-4: Projected Average Temperatures for Lyon County

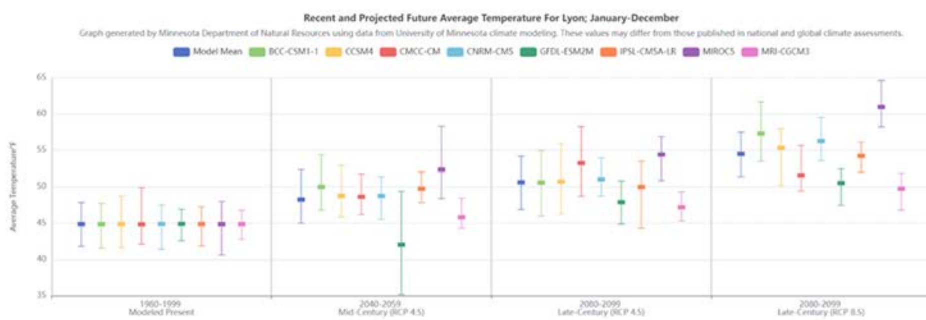
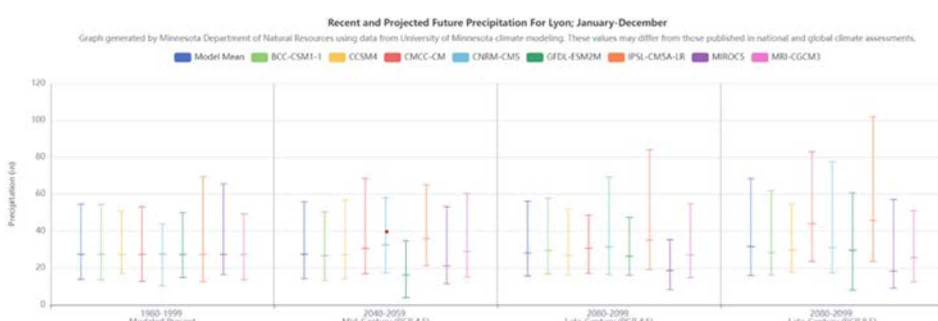


Figure 6-5 shows the projected annual precipitation amounts for Lyon County. The mean model of annual precipitation for present day (1980-1999) was 27.37 in. For the RCP 4.5 scenario for mid-century (2040-2059), the mean model predicted annual precipitation to be 27.40 in. For the RCP 4.5 scenario for late century (2080-2099), the mean model predicted annual precipitation to be 28.18 in. For the RCP 8.5 scenario for late century (2080-2099), the mean model predicted annual precipitation to be 31.52 in.

Figure 6-5: Projected Average Precipitation for Lyon County



USEPA's Climate Resilience Evaluation and Awareness Tool (CREAT) was used to determine the projected storm intensification for Lyon County, Minnesota. The projected future categories include a Stormy and Not as Stormy scenario, based on the highest and lowest intensity models, respectively, for two time periods, 2035 and 2060. The 100-year storm intensity under the Not as Stormy scenario is projected to increase 3.9 percent in 2035 and 7.5 percent in 2060. The 100-year storm intensity under the Stormy scenario is projected to increase 15.3 percent in 2035 and 29.8 percent in 2060.

For each resource category in Table 6-8 below, describe how the project's proposed activities and how the project's design will interact with those climate trends. Describe proposed adaptations to address the project effects identified.

Table 6-8: Proposal's Expected Interaction with Climate Trends and Proposal Adaptations

Resource Category	Climate Considerations	Proposal Information	Adaptations
Proposal Design	Increase in average surface temperature.	Proposal will include installation of impermeable pavement which absorbs heat during the day and releases it at night, increasing surface temperature of the surrounding area.	None proposed. Proposal will limit installation of impermeable pavement as much as possible.
Land Use	Increase in annual precipitation could lead to localized flooding.	Proposal will convert existing land use to industrial and will increase amount of impervious surfaces.	Stormwater management will be used to control water runoff.
Water Resources	Increase in amount of groundwater used.	Proposal will require water for evaporative cooling and turbine washdowns.	None proposed. Proposal will not withdraw more water than permitted.

Resource Category	Climate Considerations	Proposal Information	Adaptations
Contamination/ Hazardous Materials/Wastes	Increase in storm intensity.	Proposal includes the construction of storage tank(s) to hold No. 2 fuel oil for emergency generators.	Spill measures will be put in place (SPCC) to meet minimum regulatory standards.
Fish, wildlife, plant communities, and sensitive ecological resources (rare features)	Increase in annual precipitation and average temperature could lead to habitats loss.	Proposal will convert existing land use to industrial, so there may be some habitat loss.	None proposed.

6.9 Socioeconomic Impacts.

6.9.1 Workforce Required.

The Lyon County Station will result in up to 170 construction jobs during the 18-month period of construction. These jobs will include construction management staff, site superintendents, skilled craftsmen, engineers, start-up support personnel, and other miscellaneous services. Manufacturer's representatives will be onsite periodically; although, these representatives will not significantly increase the number of workers onsite at any given time. Craft labor, including carpenters, heavy equipment operators, laborers, millwrights, ironworkers, masons, pipefitters, and electricians, will be required during construction. Other staff will also be onsite during construction, such as management, engineering, technical, and start-up staff. The number of workers onsite will begin at nominal levels at the beginning of construction and steadily increase over time. Contractors will be chosen from a competitive bid process and will be local whenever practical. The workforce may be sourced from multiple locations locally or nationwide. Construction contractors and subcontractors will supply staff for management, engineering, technical, start-up, and other support staff. Skilled labor, including carpenters, heavy equipment operators, laborers, millwrights, ironworkers, insulators, painters, boilermakers, sheet metal workers, masons, pipefitters, electricians, etc., will be sourced as available from subcontractors and/or local union labor halls.

Operation of the Lyon County Station will require approximately five full-time permanent jobs. The future operational staff will require a group of individuals trained to operate and maintain a CT-powered generation facility. The training and skills required will include but not be limited to Proposal-specific trained control operators, maintenance technicians, and supervisory personnel.

6.9.2 Environmental Justice.

The Commission required project proposers to identify "whether the proposal is located in an environmental justice area using census criteria in Minnesota Statute 216B.1691, subd. 1(e.)"[54] That statute provides:

> (e) "Environmental justice area" means an area in Minnesota that, based on the most recent data published by the United States Census Bureau, meets one or more of the following criteria:
>
> (1) 40 percent or more of the area's total population is nonwhite;
>
> (2) 35 percent or more of households in the area have an income that is at or below 200 percent of the federal poverty level;
>
> (3) 40 percent or more of residents over the age of five have limited English proficiency; or
>
> (4) the area is located within Indian country, as defined in United State Code, title 18, section 1151.

The census tract in which the Lyon County Station is proposed to be located does not meet any of the above definitions of an "environmental justice area". Accordingly, no impacts to environmental justice areas are anticipated.

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[54] *In the Matter of Xcel Energy's Competitive Resource Acquisition Process for up to 800 Megawatts of Firm Dispatchable Generation*, MPUC Docket No. E-002/CN-23-212, Order Approving Petition and Requiring Compliance Filing at 10 (Nov. 3, 2023).

6.9.3 Energy Justice.

The Commission required project proposers to provide the following information "necessary for consideration of Energy Justice factors:"

The socioeconomic factors of a project's location;

The Proposal is anticipated to have positive direct and indirect socioeconomic impacts. With respect to direct impacts, construction of the Proposal would require approximately 170 jobs, and operation would require approximately five permanent jobs. Likewise, the Proposal is anticipated to generate approximately $5.75 million in property tax revenue each year. Indirectly, the Proposal would support continued reliable and economical electric service in Minnesota, further integration of renewable energy generation, and the retirement of higher emitting coal generation. Further, because the Proposal is not located within an environmental justice area, it would not be anticipated to have disproportionate impacts on any environmental justice populations.

The involvement of local government, community organizations, and, where relevant, Tribal Nations;

Xcel Energy has engaged in outreach and coordination with stakeholders, including local government units and Tribal Nations, in the vicinity of the Lyon County Station as part of the Company's efforts related to MNEC. Xcel Energy anticipates that this outreach will continue for MNEC, as well as for this Proposal if it is selected by the Commission.

The estimated local property tax revenue it will produce;

The Lyon County Station is anticipated to result in approximately $280 million in local tax revenue over the 40-year life of the project.

The temporary and permanent jobs it will create; and

See Sections 6.9.1 and 6.9.3.1 above.

The commitment to the use of diverse suppliers, as demonstrated by a history of use on recent projects; and

Xcel Energy has a long-standing commitment to the economic development of the communities we serve. Our Supplier Diversity program is a testament to that commitment and is based on our belief that we obtain the best products and services when we have a broad base of supplier relationships. This approach not only reduces overall costs but also offers new, innovative solutions.

Through the Company's Supplier Diversity program, the Company ensures that its employee base and network of suppliers and contractors reflect the communities it serves. To strengthen business relationships, Xcel Energy has implemented several strategies:

- Conducting outreach efforts to seek, identify, and encourage supplier diversity in procurement processes;
- Facilitating alliances and partnerships;
- Educating businesses about procurement and business processes; and
- Identifying and encouraging subcontracting (Tier II) opportunities with major non-diverse prime suppliers when direct opportunities for diverse suppliers do not exist.

Xcel Energy's Supplier Diversity program recognizes diverse businesses in various categories, including Disabled Owned Business Enterprise, Historically Underutilized Business Zone Business, LGBT Owned Business Enterprise, Minority Owned Business Enterprise, Service-Disabled Veteran Owned Business Enterprise, Small Disadvantaged Business, Veteran Owned Business Enterprise, and Women Owned Business Enterprise.

The Company actively engages in regional and national chambers and associations to meet new diverse partners. We also encourage businesses to obtain certification through one of the recognized organizations or their regional affiliates. Xcel Energy also accepts self-certification of diverse businesses with registration on Sam.gov. The certifying chambers and associations acknowledged by Xcel Energy include the National Minority Supplier Development Council, National Veteran Owned Business Association, National Veteran Business Development Council, Women's Business Enterprise National Council, National Gay/Lesbian Chamber of Commerce, and Disability:IN.

Xcel Energy views diversity as an essential component of our business success. We believe a workforce that represents the communities it serves is key to creating an inclusive and collaborative culture. A supplier base that supports diverse-owned businesses is vital to delivering the energy services customers want and need at an affordable price.

Supplier diversity offers new, innovative solutions as Xcel Energy leads the path toward the nation's clean energy transition, aligning with its vision for a pragmatic, affordable carbon-free future. That is why in 2023, the Company increased its supplier diversity goal to 25 percent of its spending on materials and services by 2025, up from 11 percent in 2022. Fulfilling this commitment will expand Xcel Energy's supply lines, creating a multiplier effect that results in additional jobs across the economy and in our communities.

<u>The payment of prevailing wages, and workforce training opportunities.</u>

In its cover letter accompanying this filing, the Company confirms that all Construction Craft Employees utilized in our proposal will be covered by a collective bargaining agreement with a union affiliated with the local council of North America's Building Trades Unions (Building Trades CBA). This ensures that the Proposal not only contributes to the energy infrastructure but also supports fair wages and continual skill development for the workforce involved. It reflects Xcel Energy's dedication to both operational excellence and social responsibility.

Xcel Energy has a good track record of the payment of prevailing wages and providing workforce training opportunities. For instance, the Sherco Solar project, which is replacing the retired coal units, is expected to support the creation of well-paying union construction jobs, and will support Xcel Energy's Power Up program, a recently approved Workforce Training and Development program designed to integrate historically marginalized communities into the energy workforce. Moreover, we are managing the transitions of Minnesota coal plants without layoffs. We are working with employees, communities, and other stakeholders to manage the transition through attrition, retirements, and retraining. These initiatives demonstrate Xcel Energy's commitment to ensuring fair wages and continual skill development for the workforce involved. It reflects our dedication to both operational excellence and social responsibility.

6.10 <u>Additional Information Related to Power Plants (Minn. R. 7849.1500, subp. 2).</u>

The following information is provided in response to Minn. R. 7849.1500, subp. 2, which identifies certain additional information related to power plants that must be included in an environmental analysis prepared by the Department of Commerce.

A. the anticipated emissions of the following pollutants expressed as an annual amount at the maximum rated capacity of the project and as an amount produced per kilowatt hour and the calculations performed to determine the emissions: sulfur dioxide, nitrogen oxides, carbon dioxide, mercury, and particulate matter, including particulate matter under 2.5 microns in diameter;

See Sections 6.7 and 6.8.

B. the anticipated emissions of any hazardous air pollutants and volatile organic compounds;

See Sections 6.7 and 6.8.

C. the anticipated contribution of the project to impairment of visibility within a 50-mile radius of the plant;

The Proposal is not anticipated to result in the impairment of visibility within a 50-mile radius of the site. The Proposal will not emit significant amounts of visibility impairment pollutants, such as NOx, SO2, PM and sulfuric acid mist.

D. the anticipated contribution of the project to the formation of ozone expressed as reactive organic gases. Reactive organic gases are chemicals that are precursors necessary to the formation of ground-level ozone;

Ozone precursors are VOC and NOx emissions. The Proposal will not be a major for Prevention of Significant Deterioration source for NOx or VOC and thus is not a major source of ozone.

E. the availability of the source of fuel for the project, the amount required annually, and the method of transportation to get the fuel to the plant;

See Section 4.2 and Appendix B, Table B-2.

F. associated facilities required to transmit the electricity to customers;

See Sections 1.1.1, 4.1, and 4.2.

G. the anticipated amount of water that will be appropriated to operate the plant and the source of the water if known;

See Section 6.5.

H. the potential wastewater streams and the types of discharges associated with such a project including potential impacts of a thermal discharge;

See Section 6.6.

I. the types and amounts of solid and hazardous wastes generated by such a project, including an analysis of what contaminants may be

found in the ash and where the ash might be sent for disposal or reuse; and

See Section 6.6.

J. the anticipated noise impacts of a project, including the distance to the closest receptor where state noise standards can still be met.

See Section 6.2.2.

Appendix A

<u>Forecasts, System Capacity, and DMS Programs</u>

Northern States Power Company
Lyon County Generating Station Proposal
MPUC Docket No. E002 / CN-23/212
January 2024

Appendix A: Forecasts, System Capacity, and DSM Programs

1. FORECAST

a. Forecasting Overview

The Project is being proposed to meet the Company's identified need to acquire up to 800 MW of firm dispatchable resources.

In the 2019 IRP, the Commission determined that between 2027 and 2029 the Company will likely require up to 800 MW of generic firm dispatchable resources.[1] The Commission also determined that between 2027 and 2032, Xcel Energy would need approximately 600 MW more solar-powered generation and 2,150 MW more wind-powered generation, or an equivalent amount of energy and capacity from a combination of wind, solar and/or storage.[2]

This appendix discusses the need for firm dispatchable resources identified in Xcel Energy's 2019 IRP, with the understanding that the Company will be filing its next IRP in February 2024 and will supplement the record to include updated forecasting information from the 2024 IRP after it has been filed.

i. Determining Customer Needs

The Company's internally developed customer needs forecast is derived from customer demand and energy forecasts and adjustments for the effects of energy efficiency (EE) resources, distributed energy resources (DER), and electric vehicle (EV) adoption. To this, Xcel Energy adds a reserve margin that is prescribed by MISO. Then Xcel Energy subtracts the capacity accreditation of the energy resources the Company has, or expects to have, on the system, to determine the net surplus or need.

Forecasting the Company's customers' energy needs starts with a peak-hour demand forecast (in MW) and a forecast of customers' total energy needs (in MWh) for each year of the planning period.

(1) Forecast for Peak Demand Requirements

Xcel Energy uses econometric analysis and historical actual coincident net peak demand data to determine forecasted system demand, which forms the basis of the Company's capacity requirements for each planning year. From these corporate forecasts, Xcel Energy makes adjustments that add back in the effect of anticipated future EE achievements and distributed

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[1] *In the Matter of the 2020-2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy*, MPUC Docket No. E-002/19-368, Order Approving Plan with Modifications and Establishing Requirements for Future Filings at 32, ¶ 3 (Apr. 15, 2022) (IRP Order).

[2] IRP Order at 31, ¶ 2A(8).

solar generation, so that Xcel Energy can model EE and distributed solar as competing with supply-side resources in the modeling process. This was a change the Company first implemented with the Company's July 2019 initial Resource Plan filing and is further discussed below.

The methodology used to develop the Spring 2022 Forecast did not change from the initial 2019 Resource Plan filing, though the inputs used to develop the forecast were updated.

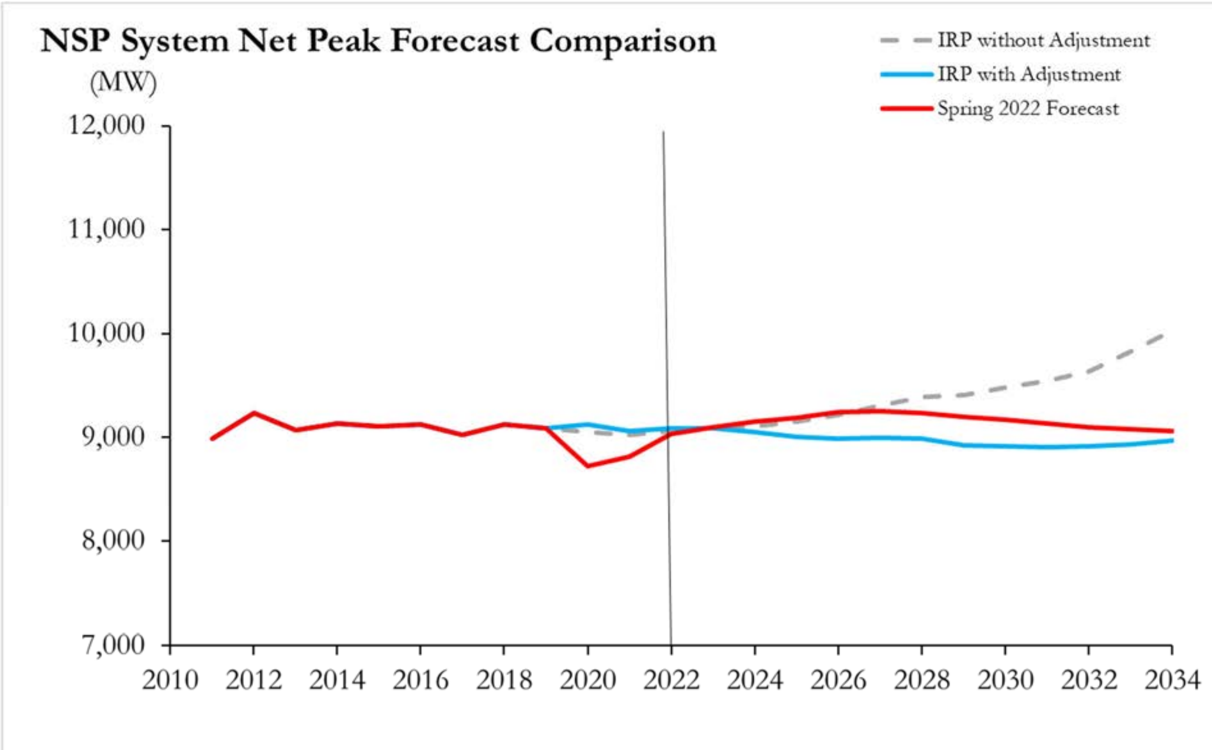
The Spring 2022 peak corporate demand forecast for this update shows an average annual growth rate of 0.02% from 2022 through 2034. Image 4.1 below shows the updated corporate net load forecast – called "Spring 2022 Forecast" in the Image 4.1 in relation to the forecast from the IRP Fall 2019 Forecast referred to as "IRP without Adjustments". In addition, Image 4.1 includes an "IRP with Adjustments" series where the Future Demand Side Management (DSM) adjustment used in the IRP forecast is updated with the Future DSM adjustment from the Spring 2022 forecast. The "IRP with Adjustments" series provides an "apples-to-apples" comparison for the Spring 2022 forecast with the IRP forecast that eliminates the differences in DSM forecasts. After accounting for the differences in the IRP and Spring 2022 forecasts in the "IRP with Adjustments" forecast, the Spring 2022 peak demand forecast exceeds the "IRP with Adjustments" peak demand forecast through the 2034 horizon. Xcel Energy undertook additional steps in the course of resource plan modeling, for incremental new EE to be modeled as a supply-side resource. This required that the Company adjust the base energy forecast (discussed in Part 1 above) to remove the embedded EE adjustment that projects the effects of new 2022-2034 program year EE achievements.[3]

In other words, after accounting for increased levels of DSM that were approved in the IRP, the updated 2022 load forecast result in a larger incremental resource need than the Company had anticipated in the IRP. This higher peak forecast is driven by a higher energy forecast which includes stronger than expected actual energy demand in 2021 and a higher level of EV adoptions over the forecast horizon. While a higher EV adoption rate results in more energy needed to support charging, a change in the EV charging profile results in lower peak impact per vehicle during the system peak hour.

[3] Xcel Energy also disaggregated DG Solar resources, as discussed previously. This included incremental potential EE savings amounts from the 2022-2034 program years in Strategist and Encompass modeling processes as "Bundles," which compete on an economic basis with supply-side resources. In effect, this allows Xcel Energy to treat projected additions of DG solar and portfolios of new EE measures, at a given average cost, like generic supply-side resources.

Appendix A: Forecasts, System Capacity, and DSM Programs

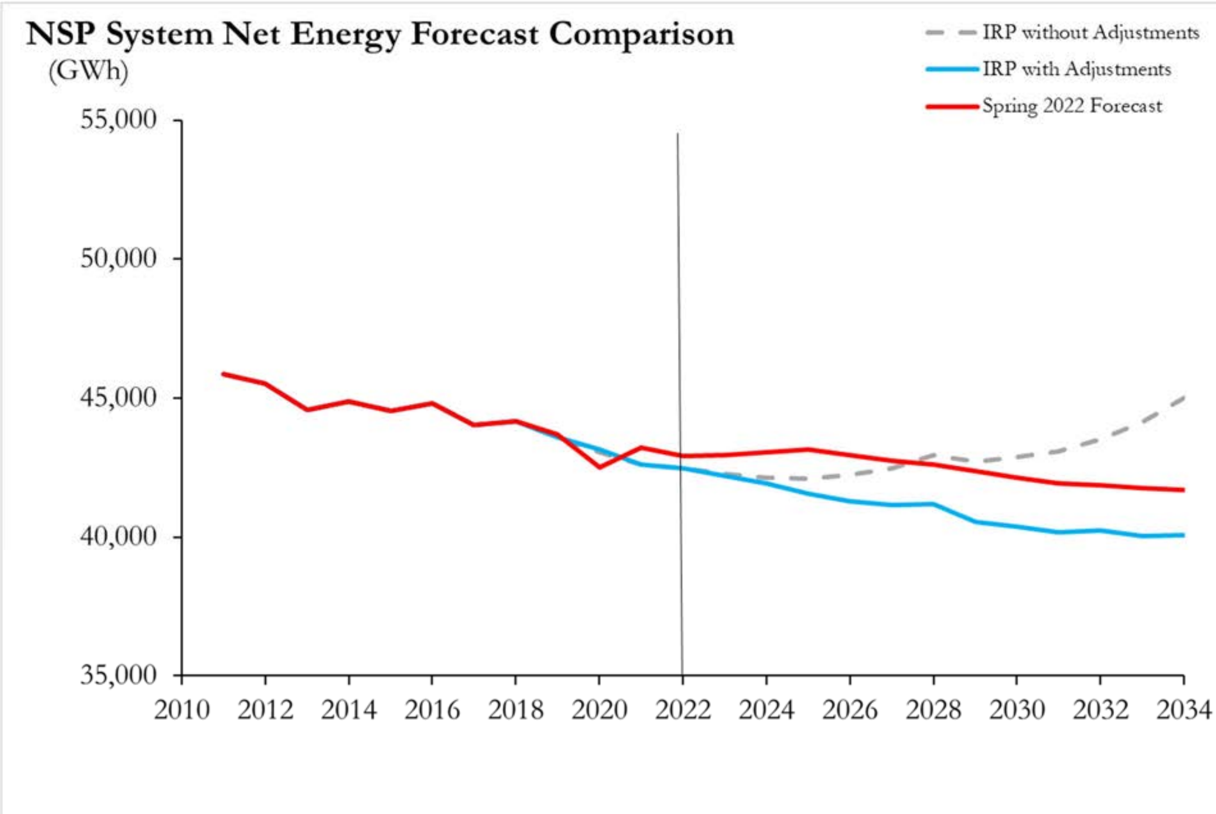
Image 4.1: Corporate Forecast of Peak Load by Vintage



(2) Forecast for Energy Requirements

In addition to forecasting peak demand, Xcel Energy also forecasts customers' energy requirements. Xcel Energy expects net energy requirements to remain above the forecasts used to determine the need for new supply side resources in the 2019 IRP filing. The Image 4.2 below portrays the net energy from the Spring 2022 forecast, as compared to the IRP Fall 2019 forecast referred to as "IRP without Adjustments". Image 4.2 also includes an "IRP with Adjustments" series where the Future DSM adjustment used in the IRP forecast is updated with the Future DSM adjustment from the Spring 2022 forecast. The "IRP with Adjustments" series provides an "apples-to-apples" comparison for the Spring 2022 forecast with the IRP forecast that eliminates any differences in DSM forecasts. Changes from the Company's Fall 2019 forecast vintage to the Spring 2022 forecast are attributable to higher than previously expected historical energy consumption, the long-term impact of the COVID-19 pandemic on customer sales, and additional sales from higher EV adoption.

Image 4.2: Corporate Forecasted Net Energy Requirements by Vintage



(3) Forecast Adjustments for Anticipated Customer Trends

After determining the base peak capacity and energy demand forecasts, Xcel Energy makes adjustments to account for the impact of events or trends reasonably expect to occur in the planning period. The forecast has been exogenously adjusted for trends in DER and adoption of EVs. DER in the form of behind-the-meter rooftop solar results in a reduction to the forecast while EV charging results in an increase to the forecast. The forecast also made certain adjustments to overall demand for large customer changes expected in future years.

(4) Adjustments to Model Certain Load-Modifying Resources as Competing with Supply-Side Resource Options

There are no changes to the methodology used in the 2019 IRP filing to account for load-modifying resources – such as energy efficiency, demand response, and distributed generation – as competing with supply-side resources in the Company's modeling process.

ii. Resource Adequacy Requirements

MISO prescribes RA requirements that are intended to help ensure adequate reliability of the bulk electric supply system. MISO's RA process requires load serving entities (LSEs) like the Company to maintain resources that exceed their level of demand by a specific margin – the planning reserve margin or PRM – to cover potential uncertainty in the availability of resources or level of demand.[4] These RA requirements are fundamental to the resource planning process, informing the level of capacity Xcel Energy needs in the Company's portfolio to adequately serve customers' peak demand.

The MISO RA construct is currently undergoing significant reform, as the system continues to transition away from legacy baseload generation assets to future state with more renewables and flexible generation. Recently, MISO proposed and FERC approved a new method to incorporate RA requirements on a seasonal basis, rather than the historical annual approach. This means that – whereas previously Xcel Energy needed to plan the system in a way that met summer peaks plus a reserve margin – Xcel Energy now will need to evaluate customer needs across summer, fall, winter, and spring, and resource availability in each season will impact capacity accreditation. Further, MISO continues to work on a new methodology for accrediting non-thermal resources, such as renewables and demand response, which continues to be considered by stakeholders and MISO now intends to file a proposed methodology to the FERC in late 2023 or early 2024. MISO may also propose further changes to the auction mechanism through which generation owners and LSEs offer and procure capacity credits to ensure full coverage of their PRM in the coming months. Overall, the Company supports development of these reforms and participates in MISO stakeholder processes to better understand and guide reform proposals.

That said, these are significant changes to the Company's planning processes and obligations, and it will likely take some time to understand implications, in the upcoming 2023-2024 Planning Year and beyond. With respect to the Project and the Company's resource plans more broadly, it is likely that the exact mix of resources Xcel Energy needs to serve customers in the future will change, in response to these new requirements (as well as other significant market changes such as new tax policy and commodity volatility). However, it is clear that the Company will need significant quantities of new generation, and the aforementioned reforms are expected to make the Project even more critical to achieving Xcel Energy's and the State of Minnesota's carbon goals and ensuring sufficient capacity on the system in the coming years.

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[4] The factors affecting availability and demand include: planned maintenance, unplanned or forced outages of generating facilities, deratings in resource capabilities, variations in weather, and load forecasting uncertainty.

Appendix A: Forecasts, System Capacity, and DSM Programs

(1) Annual MISO Reserve Margin Requirements Applied to the NSP System in the IRP

Historically, MISO based its PRM requirements on an annual analysis of the amount of reserve capacity required to avoid loss of load events, evaluated based on the system's summer peak. Based on the needs indicated in MISO's 2020-2021 Loss of Load Expectation Study (LOLE Study) – which Xcel Energy used to develop the Company's approved 2019 IRP – the Company calculated its effective reserve margin to be 3.46%. Below is a discussion on how Xcel Energy's reserve margin obligation (2022) was derived in the 2019 IRP.

For the 2020-21 planning year, MISO had indicated an unforced capacity (UCAP) PRM of 8.9%, and this requirement was expected to remain relatively constant at 8.8-8.9% over the full MISO planning period, to 2029. The Company determined the NSP-specific reserve margin based on this information, and the coincident peak demand factor of the Company's own peak load in relation to the MISO peak. The Company assumed this coincident factor to be 95%; meaning that NSP expects to experience load levels that are approximately 95% of the peak load during times when the total MISO system load is peaking. Considering the overall MISO PRM and the Company's own coincident peak factor together, the Company's NSP-system effective reserve margin declined from the 8.9% MISO-wide PRM to 3.46%.

Image 4.3: MISO Planning Reserve Margin Calculation – NSP System

Planning Year June 1, 2021 to May 31, 2022

$$(95\ percent\ coincidence\ factor) x\ (1 + 8.9\ percent) - 1 = 3.46\ percent\ effective\ reserve\ margin\ for\ NSP$$

Applying the Company's effective reserve margin to the Company's annual load forecast over the planning period determined the capacity obligation the Company needed to meet in the Company's IRP. This calculation for 2022 is illustrated below.

TABLE 4.1: CAPACITY OBLIGATION CALCULATION UNDER IRP ASSUMPTIONS – 2022 EXAMPLE

Total Capacity Obligation Component	Value
Forecasted NSP Peak Load	9,101 MW
NSP Effective Reserve Margin	x (1+ 3.46%)
NSP Obligation	**= 9,416 MW**

(2) NSP Resources Capacity Accreditation in the 2019 IRP

After the Company determined this MISO obligation level, the Company considered the types of resources suitable to meet the requirement. MISO's tariff and business practices, at the time, set forth procedures to enable various types of resources to be used to achieve the Company's RA requirements: (1) capacity resources,[5] (2) load modifying resources,[6] and (3) energy efficiency resources.[7]

Resource accreditation represents a measure of a resource's reliable contribution to System RA needs. A generator's operation, maintenance, and utilization directly impact the portion of nameplate capacity rating currently recognized as an accredited resource. Therefore, for a resource's expected contribution to RA, MISO has historically used UCAP rather than installed capacity (ICAP). This is a measure that estimates the amount of capacity that can be counted on to contribute to customer needs in peak hours. UCAP is calculated differently for dispatchable resources (e.g., nuclear, natural gas, coal), EE, and DR as compared to non-dispatchable, variable resources (e.g., wind and solar).[8]

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[5] Physical Generation Resources (i.e., physical assets and purchase agreements), External Resources if located outside of MISO's footprint, and DR Resources participating in MISO's energy and operating reserves market, available during emergencies.

[6] Behind-the-Meter Generation and DR available during emergencies, which reduces the demand for energy supplies coming from the LSE.

[7] Energy Efficiency Resources: Installed measures on retail customer facilities designed and tested to achieve a permanent reduction in electric energy usage while maintaining a comparable quality of service.

[8] *See In the Matter of the 2020-2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy*, MPUC Docket No. E-002/RP-19-368, 2020-2034 Upper Midwest Integrated Resource Plan at 53 (June 25, 2021) (Alternate Plan).

The RA values for most types of resources have not historically changed significantly year over year -- in particular thermal resources that were available to run during summer peak needs. For variable resources, however, especially wind – MISO modifies its assigned RA values from time to time. In the 2020 report the Company used for the approved IRP, MISO assigned wind an Effective Load Carrying Capability (ELCC) of 16.7% for wind in Zone 1.[9] This means that for every 100 MW of installed wind capacity, the Company counted 16.7 MW toward the Company's UCAP-denominated RA requirements. MISO does not, as a matter of practice, issue guidance regarding forward-looking wind ELCC values, so the Company used 16.7% across the planning period. As noted, MISO re-evaluates this value each year, but for wind the changes are generally small; for example, for the 2022-23 planning year, the value changed to 16.9%.

For solar resources, it is widely accepted within the industry and confirmed by MISO studies that, as solar capacity on the MISO grid increases, it is expected to contribute a diminishing marginal amount of RA capacity value.[10] In response, MISO's Transmission Expansion Plan analysis that was most current at the time of the Company's IRP uses solar capacity accreditation values that start at the current 50% level in 2020-2023 and decline to 30% by 2033. The Company elected to mirror this assumption in the Company's 2019 IRP modeling.

After assessing the Company's anticipated load and MISO requirements, the Company compares Xcel Energy system-wide obligations to the resources the Company already has – existing or approved – on the Company's system. While this does not yet reflect the seasonal RA construct that will be in place going forward – discussed further below – the Company's revised load and resources table shows that the result is an increased net accredited capacity deficit relative to the Company's approved 2019 IRP.

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[9] *See* MISO, *Planning Year 2020-2021 Wind & Solar Capacity Credit*, at 4 (December 2019), available at: https://cdn.misoenergy.org/2020%20Wind%20&%20Solar%20Capacity%20Credit%20Report408144.pdf (last accessed Jan. 20, 2024).

[10] For example, DTE Energy, Indianapolis Power & Light and Dominion Virginia and the California Public Utilities Commission– among others – have all used declining solar ELCC in their resource planning modeling.

TABLE 4.2: 2020-2034 SYSTEM NET ACCREDITED CAPACITY SURPLUS/DEFICIT PRIOR TO EXPANSION PLANNING (MW, RESOURCE VALUES MEASURED IN TERMS OF UCAP)

Year	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Obligation with Reserves, less Existing EE	9,655	9,695	9,748	9,770	9,761	9,767	9,758	9,685	9,669	9,624	9,604
Existing Fossil Thermal	6,154	6,154	5,320	5,011	4,603	3,448	3,448	2,965	2,454	2,340	2,064
Existing Nuclear	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,642	1,642
Existing Large Hydro	831	831	831	0	0	0	0	0	0	0	0
Existing Renewables	1,625	1,581	1,641	1,522	1,497	1,474	1,417	1,373	1,349	1,300	1,267
Existing Demand Response	1,041	1,055	1,066	1,072	1,077	1,078	1,077	1,071	1,059	1,048	1,037
Net Surplus/(Deficit) before New Resources Added	1,637	1,567	753	(523)	(944)	(2,126)	(2,175)	(2,635)	(3,166)	(3,295)	(3,595)

(3) Changes to planning reserve margins and resource accreditation in the recently approved MISO RA construct

MISO is in the process of significantly reforming the capacity accreditation and obligation construct, with the goal of ensuring reliability as the utilities within MISO transition away from traditional baseload generation and toward a more flexible system that relies more heavily on variable renewables. In 2022, MISO submitted a proposal to change its resource adequacy construct from an annual assessment – that focuses primarily on summer peak – to a seasonal process where each load serving entity (like Xcel Energy) would have distinct reserve requirements and resource accreditation values for each season. FERC recently approved seasonal accreditation methods for thermal resources and identifying seasonal needs, and further work is being done to identify a new method of accreditation for non-thermal resources. MISO is still in the process of finalizing the accreditation values the Company will use for the upcoming planning year, as of the date of this filing. As a result, the Company has not yet fully updated the Company's resource plan modeling to account for these changes, but they are discussed qualitatively below.

Accreditation approach

First, MISO has initiated changes to the method by which thermal resources are accredited. To date, thermal resources have been accredited based on their deliverable capacity, discounted by their forced outage rate. MISO has used a rolling three-year average of the forced outage rate which tends to stay fairly stable over time for thermal resources, as a general statement.

MISO's stated purpose in pursuing its seasonal accreditation construct was to "assure that Resources are available when needed the most by aligning Resource accreditation with availability during the highest risk hours in each Season."[11] In the new construct, each resource will get a separate accreditation value for summer, fall, winter, and spring. These accreditation values will be calculated to account for the resources availability in high risk hours for each region during each season, rather than only applying a forced outage rate to the deliverable output. MISO intends this change to better account for non-summer system risks, whereas the previous annual construct planned for summer and essentially assumed that sufficient capacity would then be available for all other seasons at the system level, given MISO is summer peaking as a whole.

[11] MISO Correspondence, at 4 (Nov. 30, 2021), available at https://elibrary.ferc.gov/eLibrary/filedownload?fileid=5C874A8F-4C12-C0D4-AF05-7D7262000000 (last accessed Jan. 20, 2024).

At this time the seasonal accreditation approach is only finalized and approved for thermal resources. Non-thermal resource – such as wind, solar, battery energy storage and load modifying resource – accreditation is still under development and is slated to be filed to FERC later in 2023 or early 2024. For the upcoming planning year, non-thermal resources will receive an accreditation value for each season, but the approach by which those values are determined will be subject to change in the future.

Updated MISO accreditation values will be provided with the 2024-2040 IRP. In general, the Company expects thermal resources to retain a fairly high accreditation across seasons, except for those resources that took relatively long outages or have extended start-up times in the past three years. In the future, the Company and other generation owners will likely adjust their outage schedule plans to better optimize around their individual seasonal needs.

Planning reserve margin approach

In conjunction with seasonal accreditation, MISO will also be calculating planning reserve margin requirements (PRMR) by season. As MISO has described in its FERC filing, the PRMR will still be designed to meet the typical 1-in-10 Loss of Load Expectation standard on an annual basis. However, a LOLE target of 0.01 will be used to calculate the PRM requirement for any season that does not exceed a 0.01 LOLE risk from the annual study.

The result of the first year of this calculation has produced the following seasonal PRMR values, which are applied to the Company's load forecast to determine the Company's overall obligation as described earlier in this section. Notably, the summer PRMR is actually lower than in past years. However, the PRMR in the winter and spring is substantial; this means that if the Company's need were perfectly coincident with the MISO system broadly, the Company would need to carry sufficient accredited capacity to meet its expected winter load, plus an additional 25.5% to meet its MISO requirements.

TABLE 4.3: PRMR VALUES FOR PLANNING YEAR 2023-2024

Season	PRMR, expressed as a percent of UCAP
Summer	7.4
Fall	14.9
Winter	25.5
Spring	24.5

Given these substantial changes – both those that have been adopted at FERC and ones that are yet to be proposed and accepted – the Company will need to reassess its plans in the future to determine the best mix of resources to meet its requirements. However, it is clear that incremental resources will be needed in substantial quantities as Xcel Energy continues to retire the Company's baseload thermal generators. Xcel Energy plans to address this need with new renewable and firm dispatchable resources to serve customers' needs, of which the firm dispatchable resource provided by the Proposal will be an integral piece.

2. LOAD FORECAST METHODOLOGY & CONSERVATION PROGRAMS

a. Load Forecast

At a high level, the Company relies on econometric models and other statistical techniques to develop the sales forecast. The econometric models relate our historical electric sales to demographic, economic, and weather variable data. Xcel Energy uses projections of economic activity for our various service areas that are provided by IHS Markit Inc. (formerly IHS Global Insight, Inc.). Based on this and other inputs, we develop sales forecasts for each major customer class, in each state of our service area. The individual class forecasts for each state are summed to derive a total system sales forecast. We then convert the sales forecast into energy requirements at the generator level by adding energy losses. The forecasted losses are developed using actual historical loss factors and are held constant over the forecast period. We develop the peak demand forecast using a regression model that relates historical monthly base peak demand to energy requirements and weather. The median energy requirements forecast and normal peak-producing weather are used in the model to create the median base peak demand forecast.

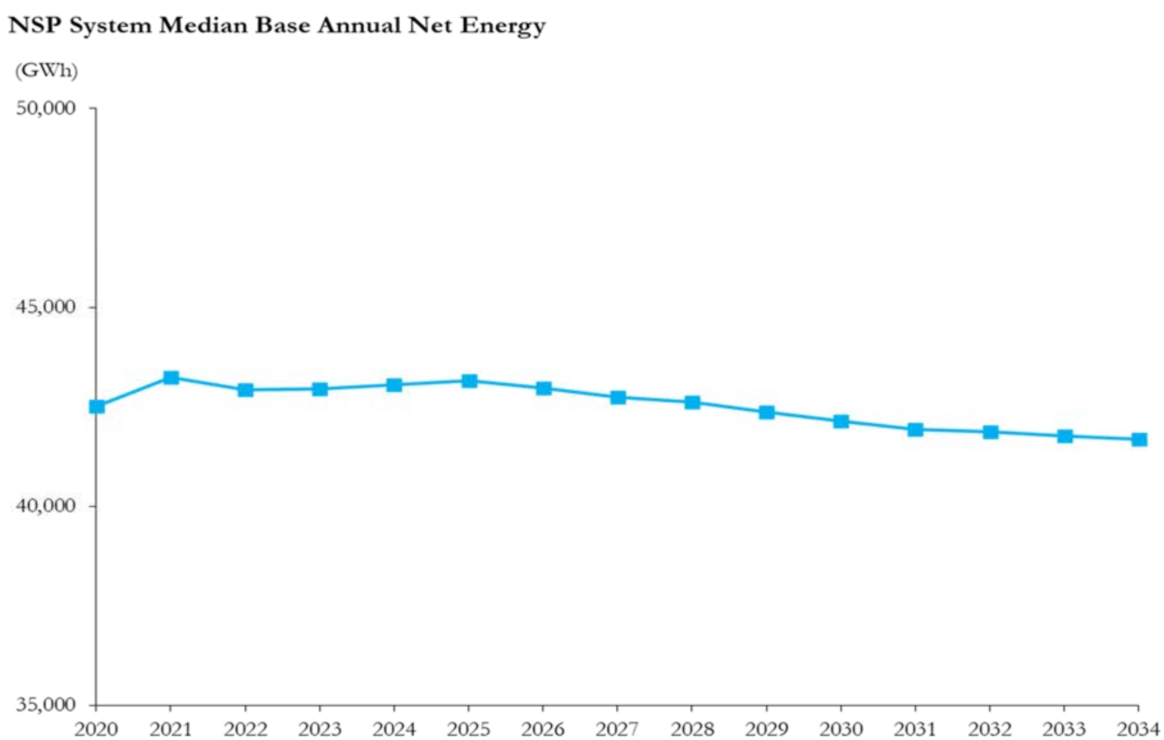
The impacts of the COVID-19 pandemic are accounted for in the modeling process. The econometric models developed for the Spring Forecast include 22 months (March 2020 – December 2021) of historical data that reflect the impact of the pandemic on company sales and peak demands. The sales regression models include a variable to account for the pandemic. The variable is developed from Google Mobility data that measure the duration of time of mobile phones located at residential, workplaces, and retail establishments relative the pre-pandemic levels at the same locations. Forecast of the Google Mobility variables are based on the historical data trends and long-term expectations of COVID-19 impacts on customer behavior. These variables fit well in the residential and small commercial and industrial sales models.

i. Base Forecast Methodology

The Spring 2022 updated base energy forecast decreases at an average annual growth rate of 0.2 percent over the 2022–2034 planning period, net of energy efficiency (EE) savings, distributed solar energy production, and electric vehicle charging consumption.

Taking these adjustments into account, the base forecasted electric energy requirements are expected to decrease at an annual average of 103 gigawatt-hours (GWh), declining from approximately 42,900 GWh in 2022 to 41,700 GWh in 2034. See Figure II-2 below.

Figure II-2: NSP System Total Median Net Energy



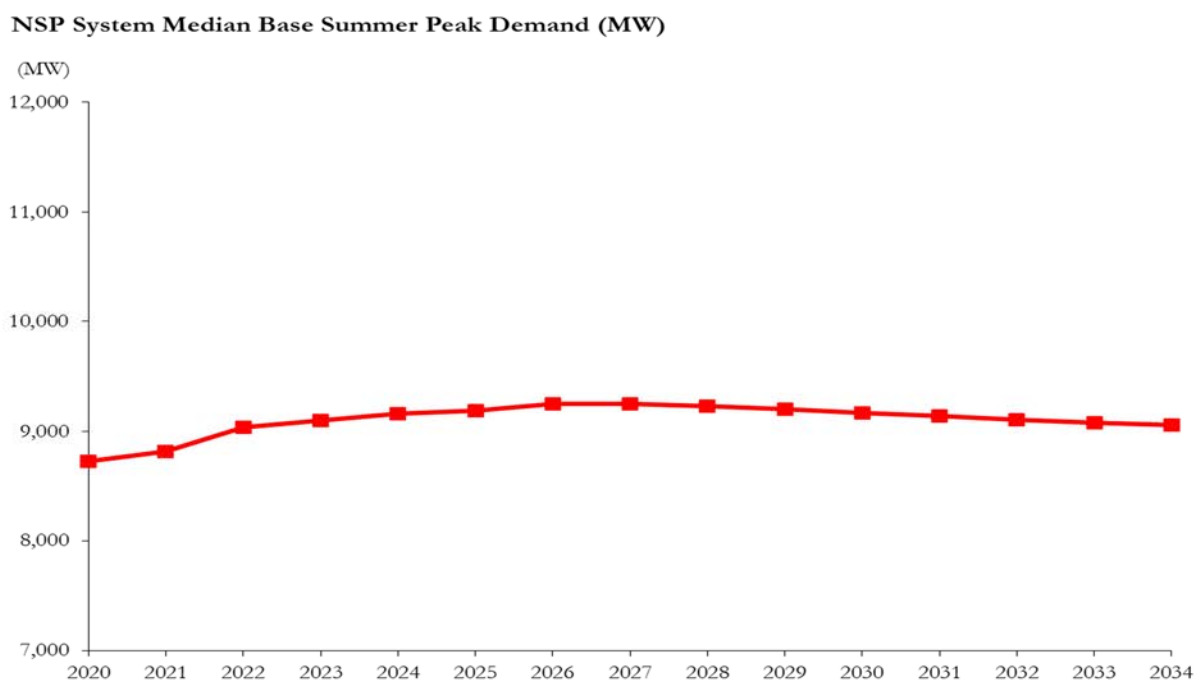
We note that the projected 0.2 percent average annual decline in electric energy requirements is similar to the actual growth seen over the past few years. After adjusting for unusual weather, electric energy requirements *decreased* at an average annual rate of 0.4 percent from 2018 to 2021.

b. System Peak Demand Forecast

i. Base Forecast

During the 2022-2034 planning period, the median base peak demand corporate forecast is essentially flat with an average annual growth rate of 0.02 percent, when including effects of already assumed EE. As demonstrated in Figure II-4 below, annual peak demand increases at an average of 2 MW each year, starting with 9,039 MW in 2022 to 9,059 MW in 2034.

Figure II-4: NSP System Median Base Summer Peak Demand



c. Key Demand and Energy Forecast Variables

The balance of this section discusses the energy and peak load forecasting methods, assumptions, analytics, adjustments, etc. to derive the Corporate System Energy Forecast presented above. In general, our approach to modeling energy and capacity demand forecasts remains consistent, even as some inputs and assumptions have been updated.

Appendix A: Forecasts, System Capacity, and DSM Programs

i. Demographics

Demographic projections are essential to the development of the long-range forecasts. The consumption of electricity is closely correlated with demographic statistics. The number of residential customers, weather data and economic indicators are key variables in the residential energy sales forecast. Over 99 percent of the variability in historical electric residential customer counts in our service territory can be explained through an econometric model that contains either population or households as key drivers. The forecasts for population and households are provided by IHS Markit Inc. We forecast an average annual growth rate for total residential customers on our system of 0.7 percent, with the addition of 11,740 residential customers on average per year from 2022 through 2034.

ii. Economic Indicators

Xcel Energy uses estimates of key economic indicators to develop electric sales forecasts. These variables include gross state product, employment, and real personal income. The variables used are specific to the jurisdiction and are statistically significant in the sales models for the residential and commercial and industrial customer classes. Growth in electric energy consumption in the residential and commercial and industrial sectors closely follows trends in economic activity. IHS Markit Inc. provided the economic forecasts used in our regression models.

For the planning period, the economy is expected to continue to grow, resulting in growth in electric energy consumption.

iii. Weather

The peak demand for electric power is heavily influenced by hot and humid weather. As the temperature and humidity rise, the demand for cooling rises steeply. Our approach to forecasting peak demand includes using a weather variable that consists of the mean of an index of heat and humidity referred to as the temperature humidity index (THI). Simply stated, the THI is an accurate measure of how hot it really feels when the effects of humidity are added to the high temperature.

We have tracked the THI at the time of the system peak demand over the past 20 years. Because of the 20 years of smoothing, the weather variable does not drastically affect our median forecasts; however, it becomes a key factor in assessing the potential peak demand if and when hot and humid weather extremes are encountered. Since Xcel Energy must have adequate generating resources available during hotter than normal circumstances, planning for the extreme is important.

d. Forecast Methodology

Xcel Energy serves customers in five jurisdictions in the upper Midwest: Minnesota, North Dakota, South Dakota, Wisconsin, and Michigan. We develop a forecast for each major customer class and jurisdiction using a variety of statistical techniques.

We first develop our system sales forecasts by using a set of econometric models at the jurisdictional level for the Residential and Small Commercial and Industrial sectors for all jurisdictions, the Large Commercial and Industrial sector for Minnesota, and the Minnesota Public Street and Highway Lighting and Public Authority sectors. These models relate our historical electric sales to demographic, economic and weather variables as detailed in the prior section of this document.

For the remaining customer classes, Large Commercial and Industrial, Public Street and Highway Lighting, and Public Authority in all states but Minnesota, and Interdepartmental, we use trend analysis and customer specific data. We compile our system sales by summing the individual forecasts for each sector in each jurisdiction.

Since some energy is lost, mostly in the form of heat created in transmission and distribution conductors, we use loss factors to convert the sales forecasts into energy production requirements at the generator. The forecasted loss factors are developed using actual historical loss factors and are held constant over the forecast period.

We have developed a regression model to relate Xcel Energy's historical uninterrupted monthly peak demand to energy requirements and weather at the time of the peak in the winter and summer seasons. The median energy requirements forecast (50/50 forecast) and normal peak-producing weather are used in the model to create the peak demand forecast.

Once the NSP System peak demand forecast is complete, a forecast is developed for the NSP System demand coincident with the MISO system peak demand. The coincident demand forecast is developed using a regression modeling approach that determines the relationship between the NSP System demand coincident with the MISO peak demand and the NSP System peak demand (not coincident with the MISO peak demand). Previously MISO only required an annual coincident demand forecast for the next planning year. The current resource plan forecast uses the NSP System demand coincident to the MISO annual peak demand during the 2022-23 planning year (June 2022 – May 2023). Beginning with the 2023-2024 planning year, MISO has requested individual seasonal peak forecasts for the Winter, Spring, Summer, and Fall seasons.

e. Corporate Forecast Adjustments

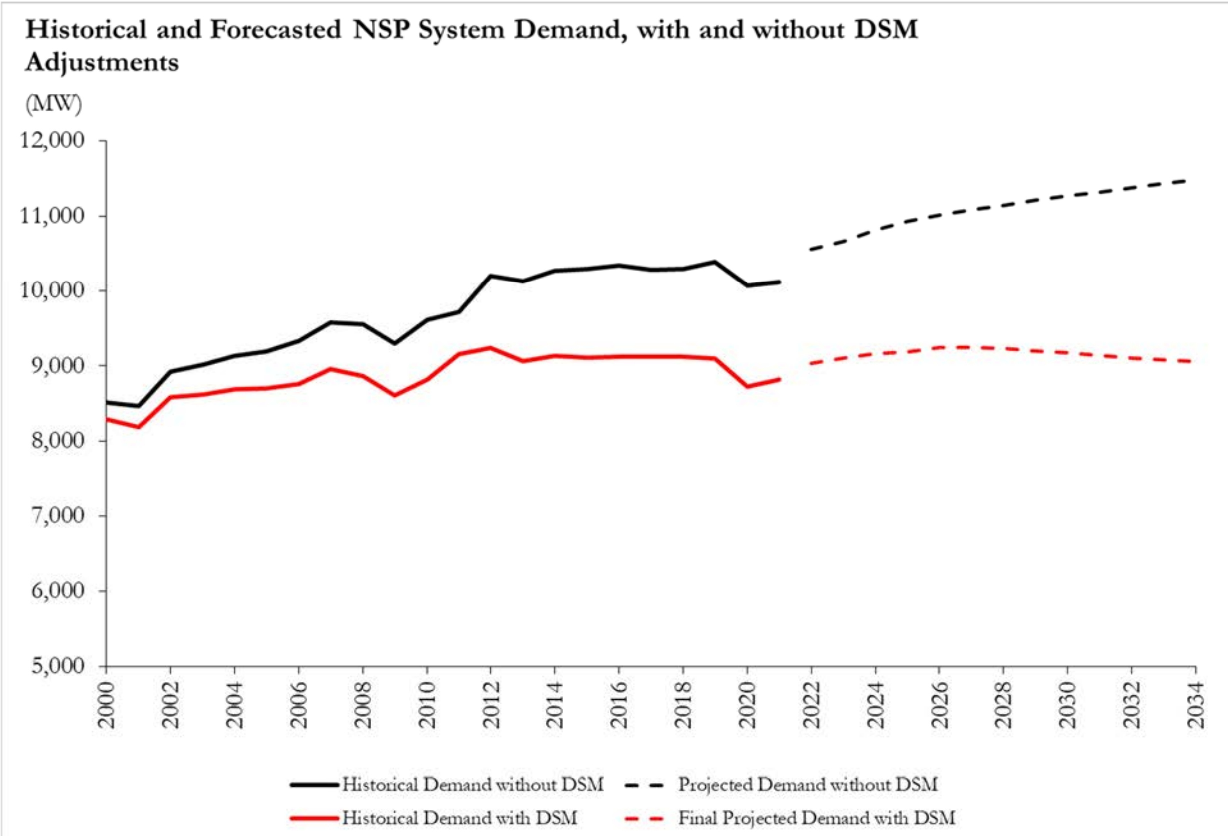
Our demand and energy forecasts are developed using a number of key forecast variables as described in this section. One important adjustment to the forecasts is to take into account our conservation or demand-side management (DSM) programs (which are discussed in Section H below).

The methodology for energy efficiency[12] includes three distinct steps to this process:

- Collect and calculate historical and current effects of EE on observed sales;
- Project the forecast using observed data with the impact of EE removed (i.e., increase historical sales to show hypothetical case without EE); and
- Adjust the forecast to show the impact of all planned EE in future years.

[12] This reference to energy efficiency is for those programs that fall under the DOC-DER's approval of our Energy Conservation and Optimization plans. The most recent approval from the Department of Commerce was on December 1, 2023. *See In the Matter of Xcel Energy's 2024-2026 Energy Conservation and Optimization Triennial Plan*, MPUC Docket No. G,E002/CIP-23-92, *et al.*, Decision (Dec. 1, 2023) (CIP Decision).

Figure II-6: Illustration of EE Adjustment – NSP System Demand



In response to the establishment of a Solar Energy Standard (SES) by the Minnesota Legislature, an increased emphasis has been placed on distributed solar generation. We developed a forecast of the expected impact on demand and energy based on new programs designed to meet goals established for the SES. We adjusted the Minnesota class-level sales forecasts and the system peak demand forecast to account for the impacts of customer-sited behind-the-meter solar installations on the NSP System. We discuss the distributed solar forecast methodology below.

After determining the base forecast, we develop net forecasts that include all adjustments, including future EE, distributed solar generation, electric vehicle charging, and the effects of our EE programs over time.

f. Additional Forecast Adjustments

We made additional adjustments to the energy and demand forecasts to account for expected changes in specific large customers' electricity usage. These additional adjustments include:

- Customers adding self-generation combined heat and power capabilities, which reduce energy consumption and peak demand; and

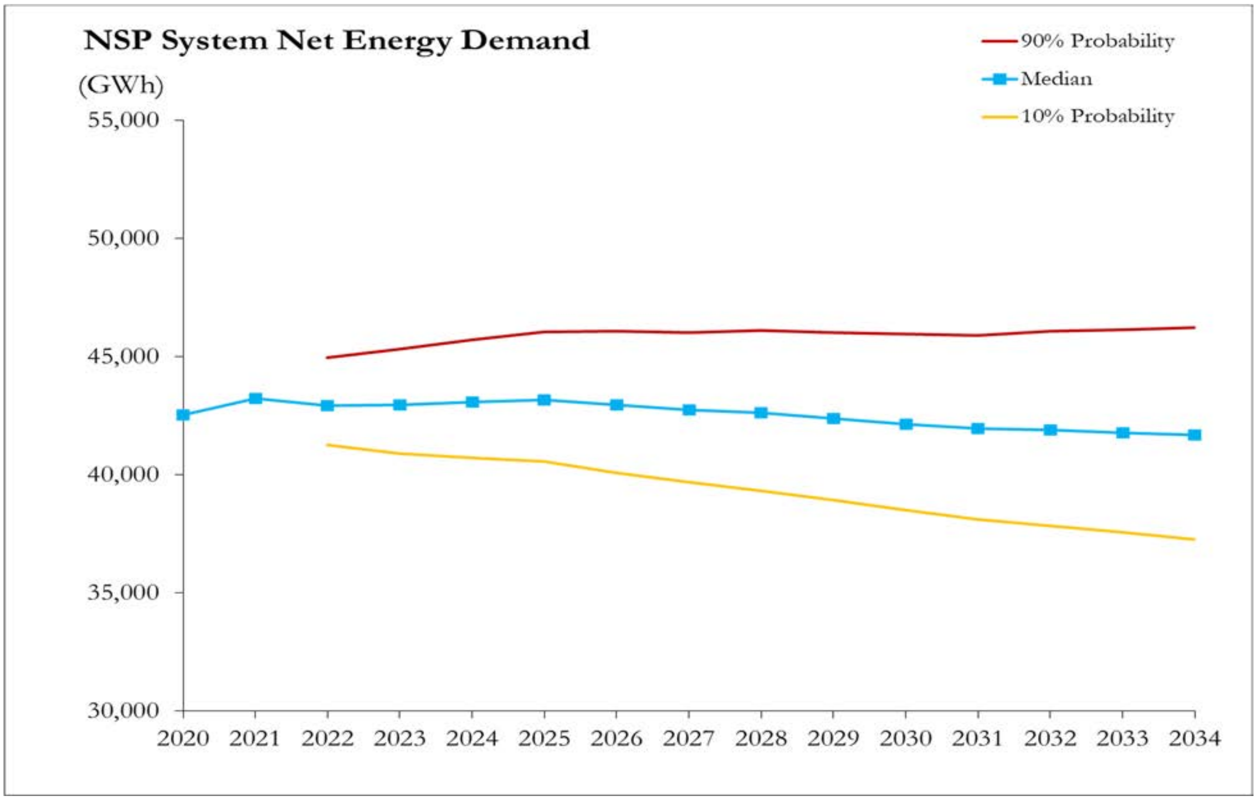
- Increases or reductions in usage due to new customers in our service territory, or planned expansions or reductions of load by existing customers, and increasing use of plug-in electric vehicle charging.

g. Forecast Variability

Given that there is uncertainty in any long-term forecast, we supplement the median forecasts with forecasts developed using statistical techniques to reflect the potential variability in energy requirements and peak demand. These probability distributions were developed using a Monte Carlo stochastic simulation of peak demand (MW) and energy (MWh). For example, the peak demand simulation involved taking 10,000 random draws from the weather probability distributions as well as 10,000 random draws from the 12-month sum of the energy probability distribution. The random draws produce 10,000 forecasts of peak demand and thus generate a probability distribution around the mean peak demand.

The probability distributions developed for this forecast yielded a 90 percent probability that the net energy will be less than 46,208,341 MWh in 2034 – or alternatively, there is a 10 percent probability that the net energy will be less than 37,267,320 MWh. See Figure II-7 below.

Figure II-7: NSP System Total Net Energy



Appendix A: Forecasts, System Capacity, and DSM Programs

Figures II-8 and II-9 below show the higher and lower variations of the 2020 to 2034 long-range forecasts of base and net summer peak demand.[13]

Figure II-8: NSP System Total Base Summer Peak Demand

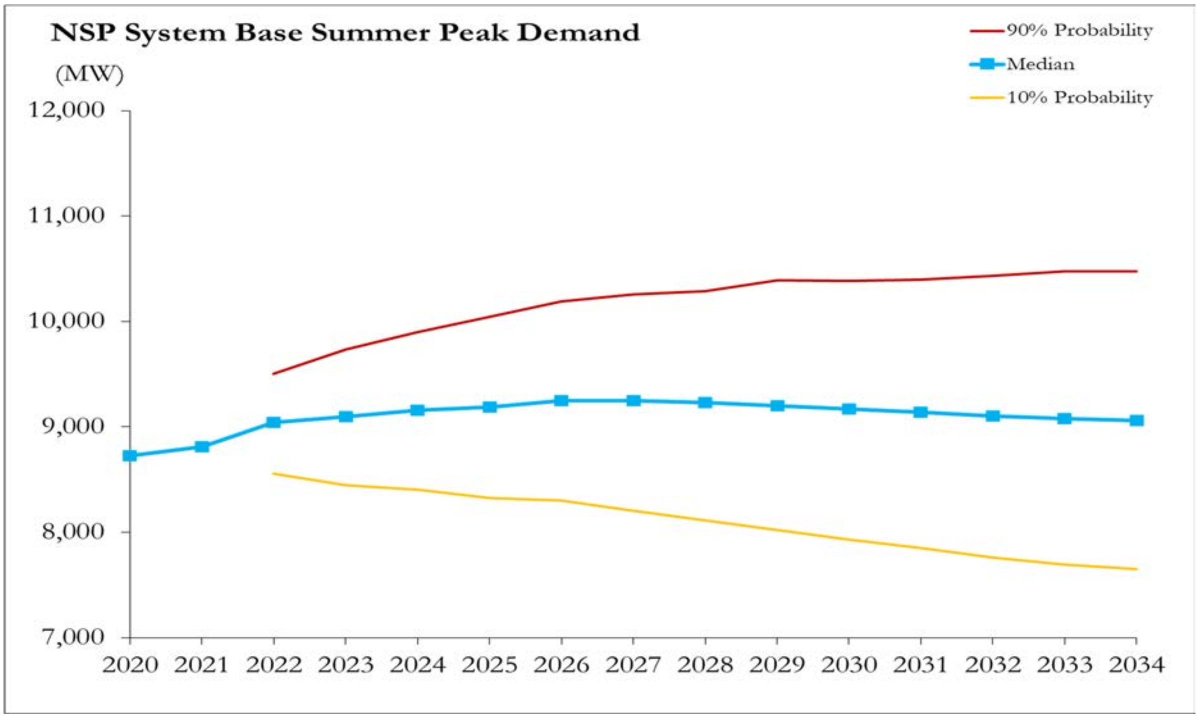
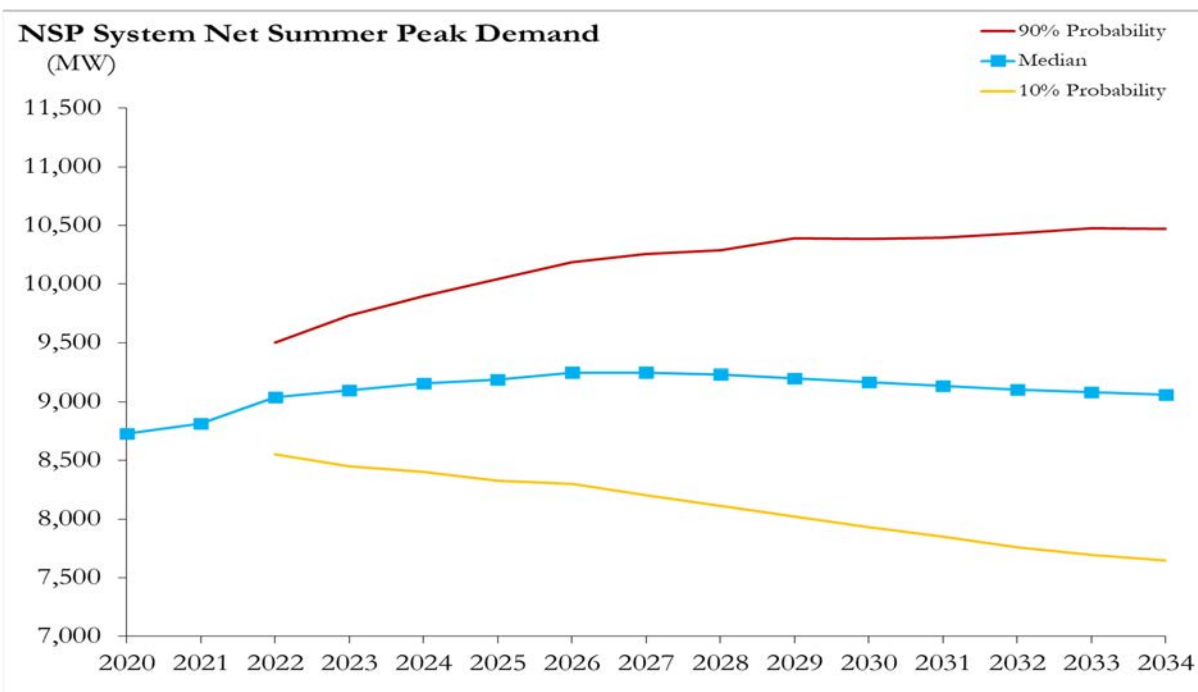


Figure II-9: NSP System Total Net Summer Peak Demand



Appendix A: Forecasts, System Capacity, and DSM Programs

Tables II-1, II-2, and II-3 below provide the data underlying Figures II-7, II-8, and II-9, respectively.

Table II-1: Annual Net Energy (MWh)

Year	90% Probability	Median	10% Probability
2022	44,939,761	42,919,537	41,240,583
2023	45,304,351	42,955,891	40,897,740
2024	45,693,920	43,059,425	40,699,428
2025	46,044,254	43,165,771	40,549,776
2026	46,059,074	42,964,345	40,081,692
2027	46,008,923	42,743,686	39,665,452
2028	46,096,820	42,617,702	39,323,931
2029	46,011,799	42,361,329	38,913,421
2030	45,936,396	42,129,463	38,483,976
2031	45,889,569	41,941,706	38,097,066
2032	46,059,881	41,878,121	37,826,308
2033	46,136,863	41,765,756	37,546,514
2034	46,208,341	41,683,472	37,267,320
Average Annual Growth 2022 - 2034	**0.2%**	**-0.2%**	**-0.8%**

Table II-2: Annual Base Summer Peak Demand (MW)

Year	90% Probability	Median	10% Probability
2022	9,503	9,039	8,553
2023	9,732	9,099	8,448
2024	9,900	9,158	8,402
2025	10,041	9,189	8,325
2026	10,187	9,250	8,300
2027	10,257	9,250	8,205
2028	10,290	9,232	8,115
2029	10,392	9,200	8,022
2030	10,383	9,170	7,929
2031	10,397	9,138	7,853
2032	10,431	9,103	7,760
2033	10,475	9,081	7,694
2034	10,473	9,059	7,649
Average Annual Growth 2022 - 2034	**0.8%**	**0.02%**	**-0.9%**

[13] Where net summer peak demand includes adjustments form the base forecast to account for interruptible load.

Table II-3: Annual Net Peak Demand (MW)

Year	90% Probability	Median	10% Probability
2022	9,503	9,039	8,553
2023	9,732	9,099	8,448
2024	9,900	9,158	8,402
2025	10,041	9,189	8,325
2026	10,187	9,250	8,300
2027	10,257	9,250	8,205
2028	10,290	9,232	8,115
2029	10,392	9,200	8,022
2030	10,383	9,170	7,929
2031	10,397	9,138	7,853
2032	10,431	9,103	7,760
2033	10,475	9,081	7,694
2034	10,473	9,059	7,649
Average Annual Growth 2022 - 2034	**0.8%**	**0.02%**	**-0.9%**

h. DSM Programs

Minnesota Rule 7849.0290 requires a Certificate of Need application to provide information related to an applicant's energy conservation and efficiency programs and a quantification of the impact of these programs on the forecast information required by Minn. R. 7849.0270. Within Xcel Energy, the Policy and Strategy team is responsible for filing our conservation and efficiency programs (also referred to as demand side management programs) at Xcel Energy. Jessica Peterson is the individual who submits these details to the DOC-DER for approval.

Conservation cannot meet the need for firm dispatchable resources that will be provided by the Project.[14] Further, Xcel Energy's conservation efficiency information has been examined in detail in prior ongoing dockets, particularly those related to the 2019 IRP and ECO; accordingly, Xcel Energy provides a summary of that information here, with references to where the information required by Minn. R. 7849.0290 may be located, rather than replicating information in this docket.

Xcel Energy's long-standing commitment in running cost-effective conservation and load management programs places the Company among the nation's top utilities in

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[14] *See* IRP Order.

terms of energy and demand saved and most innovative programs.[15] Indeed, between 1994 and 2022, the Company invested over $2.2 billion (nominal) resulting in 11,813 GWh of electric energy savings, 3,733 MW of electric demand savings and an estimated 19.9 million Dth of natural gas savings. Xcel Energy's electric ECO portfolio has surpassed the statewide target of 1.5 percent every year since 2011.[16]

Xcel Energy's 2024-2026 ECO Triennial Plan provides a description of specific energy conservation and efficiency programs the applicant has considered, including both those the applicant adopted and those that the applicant declined to adopt and why.[17] A list of specific energy conservation and efficiency programs implemented can be found in the Executive Summary of our annual Status Reports. The Company provides these in detail on our Xcel Energy website.[18] A review of ongoing new measures is conducted as new technologies are identified and reviewed compared to the cost-effective analysis required by the Department of Commerce. All additional programs reviewed and their approvals can be found in Docket No. E,G002/CIP-23-92 as required by the Department of Commerce through a "Modification Approval." Xcel Energy continued to strive to provide customers with a wide variety of options for saving energy.[19] The Triennial Plan was approved on December 1, 2023 in Docket No. E002/CIP-23-92 with saving targets of 1,871 GWh, and 3,564,652 Dth over the three-year period and at a cost of $588 million. The proposed electric savings goals also aligned with Company's DSM commitments in the 2019 IRP. In reviewing the Triennial Plan, the Department concluded:

- "[R]esidential, business, and low-income customers all appear to have opportunity to participate in the Company's ECO programs.. . . . [T]he Company proposes a variety of program delivery approaches and measures that should provide participation opportunities across market segments.".[20]

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[15] *See In the Matter of Xcel Energy's 2024-2026 Energy Conservation and Optimization Triennial* Plan, MPUC Docket No. E,G002/CIP-23-92, 2024-2026 Xcel Energy Conservation and Optimization ("ECO") Triennial Plan at 2 (June 29, 2023) (Triennial Plan).

[16] *See* Triennial Plan at 2-3.

[17] *See* Triennial Plan at 69-209.

[18] https://www.xcelenergy.com/company/rates_and_regulations/filings/minnesota_demand-side_management.

[19] Xcel Energy's next ECO Triennial Plan will be submitted on June 1, 2026.

[20] *See* CIP Decision at 68.

Appendix A: Forecasts, System Capacity, and DSM Programs

- "[T]he Company's proposed Triennial Plan is in compliance with the statutory requirements governing ECO.'"[21]

In its 2022 CIP Status Report, Xcel Energy stated that, for more than a decade, it had exceeded the State of Minnesota's energy targets. Specifically, in 2022, the electric portfolio met and surpassed the state's new energy savings target of 1.75 percent,[22] achieving nearly 648 GWh of electric savings, or 2.3 percent of sales.[23] Xcel Energy spent a total of $124 million to achieve its savings results, including $104 million on electric programs and $20 million on natural gas programs.[24]

Likewise, Xcel Energy's initial 2019 IRP filing included energy efficiency (EE) and demand response (DR) investments, and the Supplemental Plan[25] and the Alternate Plan[26] continued to reflect those investments. Xcel Energy proposed to seek to achieve EE savings levels ranging from 2 to 2.5 percent annually, achieving average savings of over 780 GWh of energy in each of 2020-2034, and more than 800 MW of additional demand savings by 2034[27] when compared to the 1.5 percent level approved in the Company's prior 2019 IRP.[28] In addition, Xcel Energy proposed an incremental 400 MW of DR by 2023. [29]

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[21] CIP Decision at 204.

[22] The ECO Act of 2021 updated the electric savings goal to 1.75 percent and the natural gas savings goal to 1.0 percent of annual retail energy sales.

[23] *See In the Matter of Xcel Energy's 2021-2023 CIP Modification Request*, MPUC Docket No. E,G002/CIP-20-473 2021, CIP Status Report at 1 (Mar. 31, 2023) (CIP 2022 Status Report).

[24] CIP 2022 Status Report at 4.

[25] *See In the Matter of the 2020-2034 Upper Midwest Integrated Resource Plan of Northern States Power Company d/b/a Xcel Energy*, MPUC Docket No. E002/RP-19-368, 2020-2034 Upper Midwest Integrated Resource Plan (June 30, 2020) (IRP Supplement Preferred Plan).

[26] *See* Alternate Plan; IRP Order at 10.

[27] Alternate Plan at 10.

[28] *See In the Matter of Xcel Energy's 2016-2030 Integrated Resource Plan*, MPUC Docket No. E002/RP-15-21, 2016-2030 Upper Midwest Resource Plan (Jan. 2, 2015); *In the Matter of Xcel Energy's 2016-2030 Integrated Resource Plan*, MPUC Docket No. E002/RP-15-21, Order Approving Plan with Modifications and Establishing Requirements for Future Resource Plan Filings (Jan. 11, 2017).

[29] Alternate Plan at 10.

Appendix B

Operational and Cost Detail

Public Document – Nonpublic Data has been Excised

Northern States Power Company
Lyon County Generating Station Proposal
MPUC Docket No. E002 / CN-23/212
January 2024

Appendix B
Project Operational and Cost Data
Lyon County Generating Station

Table B-1 Project Generating Capability, Each Turbine

Summer Conditions (95°F, 20% Relative Humidity)			
Capability		**Net Heat Rate (Btu/kWh) (HHV)**	**Efficiency (%) (HHV)**
% of Base	**MW**		
[TRADE SECRET DATA BEGINS…			
[redacted]	[redacted]	[redacted]	[redacted]
…TRADE SECRET DATA ENDS]			
Winter Conditions 30°F, 60% Relative Humidity)			
Capability		**Net Heat Rate (Btu/kWh) (HHV)**	**Efficiency (%) (HHV)**
% of Base	**MW**		
[TRADE SECRET DATA BEGINS…			
[redacted]	[redacted]	[redacted]	[redacted]
…TRADE SECRET DATA ENDS]			
Reference Temperature Conditions (52°F, 55% Relative Humidity)			
Capability		**Net Heat Rate (Btu/kWh) (HHV)**	**Efficiency (%) (HHV)**
% of Base	**MW**		
[TRADE SECRET DATA BEGINS…			
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
…TRADE SECRET DATA ENDS]			

Table B-2 Project Fuel Requirements – Lyon County Generating Station

Rule Reference	Description	Project Data
		[TRADE SECRET DATA BEGINS…
7849.0320, C(1)	Fuel Source	[redacted]
7849.0320, C(2)	Fuel Requirement •summer, peak (95F) •winter, peak (30F) •reference temperature, base load (52F) •Annual consumption (52F)	[redacted] [redacted] [redacted] [redacted]
7849.0320, C(3)	Heat Input (HHV) •summer, peak (95F) •winter, peak (30F) •reference temperature, base load (52F)	[redacted] [redacted] [redacted]
7849.0320, C(4)	Fuel Heat Value	[redacted]
7849.0320, C(5)	Fuel Content: Sulfur Ash Moisture Content	[redacted] [redacted] [redacted]
		…TRADE SECRET DATA ENDS]

Table B-3
Project Cost Summary Lyon County Generating Station

Item	Lyon County Generating Station
In-Service Date	December 2027
	[TRADE SECRET DATA BEGINS...
Project Base Capacity Cost	[redacted]
Base Summer Capacity Costs in $/kW	[redacted]
Transmission Cost	[redacted]
Fuel Cost (connection)	[redacted]
Base Total Cost in $/kWh (In-Service Year)	[redacted]
Annual Revenue Requirement in $/kWh (In-Service Year)	[redacted]
Fuel Costs in $/kWh (In-Service Year)	[redacted]
Variable O&M Costs in $/kWh (In-Service Year)	[redacted]
Estimated Effect on Rates $/kWh (MN & Total System)	[redacted]
Sunk Costs if Canceled	[redacted]
Estimated amount of construction payroll to economy	[redacted]
	...TRADE SECRET DATA ENDS]
Estimated number of construction jobs	170 FTEs
Estimated number of operations jobs	5 FTEs

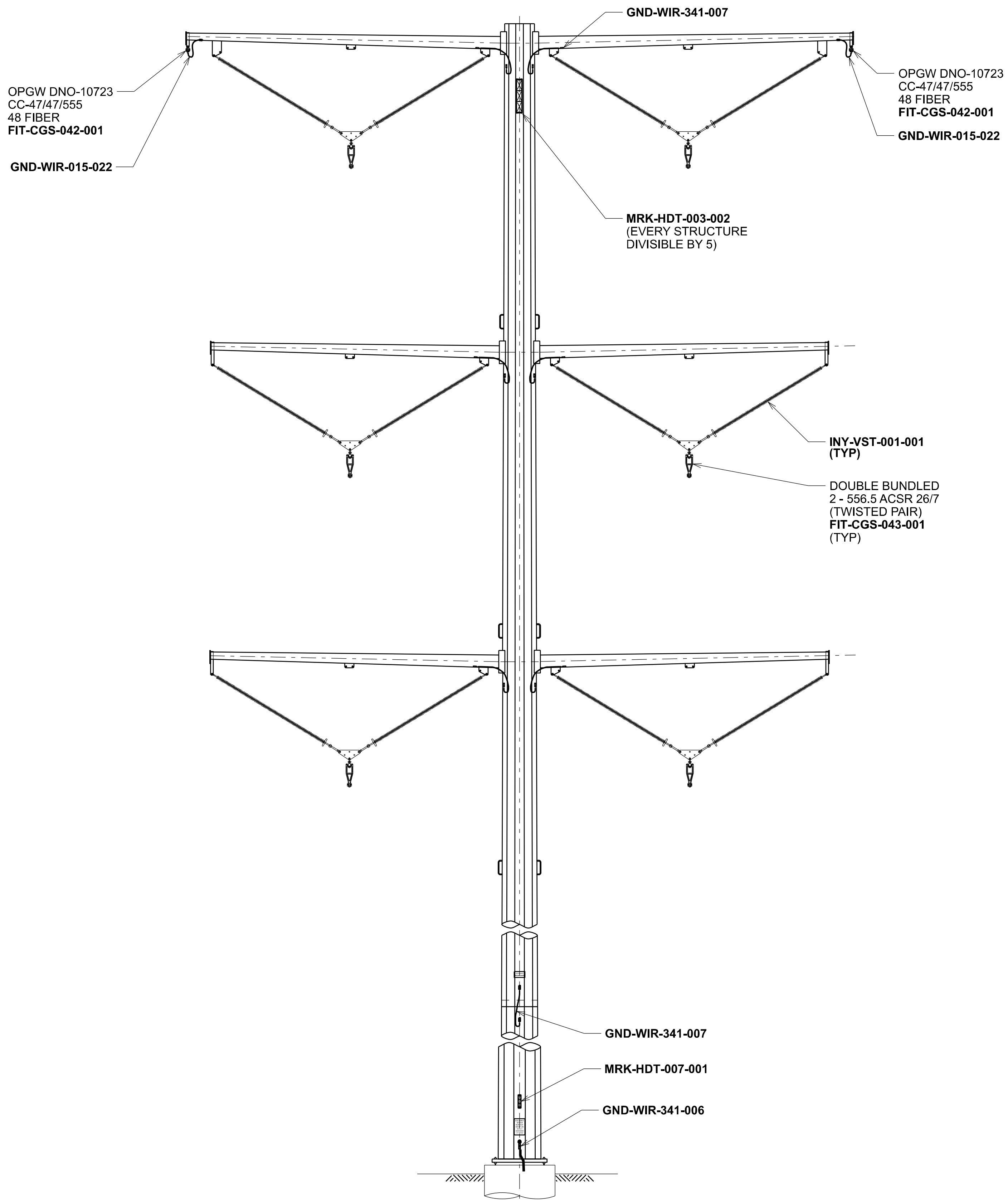
Table B-4
Minnesota Requirements

Rule Reference	Description	Project Data
7849.0250, A(1)	Nominal Generating Capability of each Unit	210 MW
7849.0250, A(2)	Operating Cycle	Simple Cycle
7849.0250, A(2)	Expected Annual Capacity Factor	10%
7849.0250, C(2)	Service Life	40 years
7849.0250, C(3)	Estimated Average Annual Availability	+95%
7849.0320, A	Estimated Land Requirements	Up to approximately 40 acres for CTs and associated facilities
7849.0320, E (1)	Estimated Maximum Groundwater Pumping Rate for each Unit Surface Water Appropriation	67 gal/min None
7849.0320, E (2)	Estimated Annual Project Groundwater Appropriation (assuming RO purification process)	788 gal/year
7849.0320, E (3)	Annual Project Surface Water Consumption	None

Appendix C

<u>Technical Diagrams of Typical 345 kV Structures</u>

Northern States Power Company
Lyon County Generating Station Proposal
MPUC Docket No. E002 / CN-23/212
January 2024



ELEVATION VIEW

NOTE:
SUB-ASSEMBLY FOR JOINT BONDS WILL BE ADDED TO EACH PLS POLE MODEL.

INSTALL BONDING GND-WIR-341-007 ACROSS ALL STEEL SHAFT SLIP JOINTS

STRUCTURE XP#	POLE HEIGHT	TOTAL NUMBER OF SLIP JOINT BONDING REQUIRED
PST17159	125'-0"	2
PST17160	130'-0"	2
PST17161	135'-0"	2
PST17162	140'-0"	2
PST17163	145'-0"	2
PST17164	150'-0"	2
PST17165	155'-0"	3
PST17166	160'-0"	3
PST17167	165'-0"	3

CONSTRUCTION NOTE:

WHEN INSTALLING ARMS TO SHAFT BONDS DO NOT CONTACT ANY PART OF THE POLYMER INSULATOR.

CONSTRUCTION NOTE:

IF CABLES ARE USED TO TIE DOWN ARMS PRIOR TO WIRE INSTALLATION, DO NOT ALLOW TIE DOWN CABLES TO CONTACT ANY PART OF THE POLYMER INSULATOR.

ASSEMBLY
STR ND-279464-1
FOR STEEL POLES
STL ND-279454-PST17159
STL ND-279454-PST17160
STL ND-279454-PST17161
STL ND-279454-PST17162
STL ND-279454-PST17163
STL ND-279454-PST17164
STL ND-279454-PST17165
STL ND-279454-PST17166
STL ND-279454-PST17167
LD ND-279418

QTY	SUBASSEMBLIES
2	FIT-CGS-042-001
3	FIT-CGS-043-001
2	GND-WIR-015-022
1	GND-WIR-341-006
6	GND-WIR-341-007
3	INY-VST-001-001
1	MRK-HDT-007-001

ASSEMBLY
STR ND-279464-2
FOR STEEL POLES
FOR SECOND CIRCUIT

QTY	SUBASSEMBLIES
3	FIT-CGS-043-001
3	INY-VST-001-001

ND-279464-1.DGN

DRAWING REFERENCE

PLAN & PROFILE ____________ ND-279505
SUBASSEMBLY INDEX ____________ NL-279504

THIS PE SEAL IS ONLY APPLICABLE TO THE CURRENT CONSTRUCTION REVISION

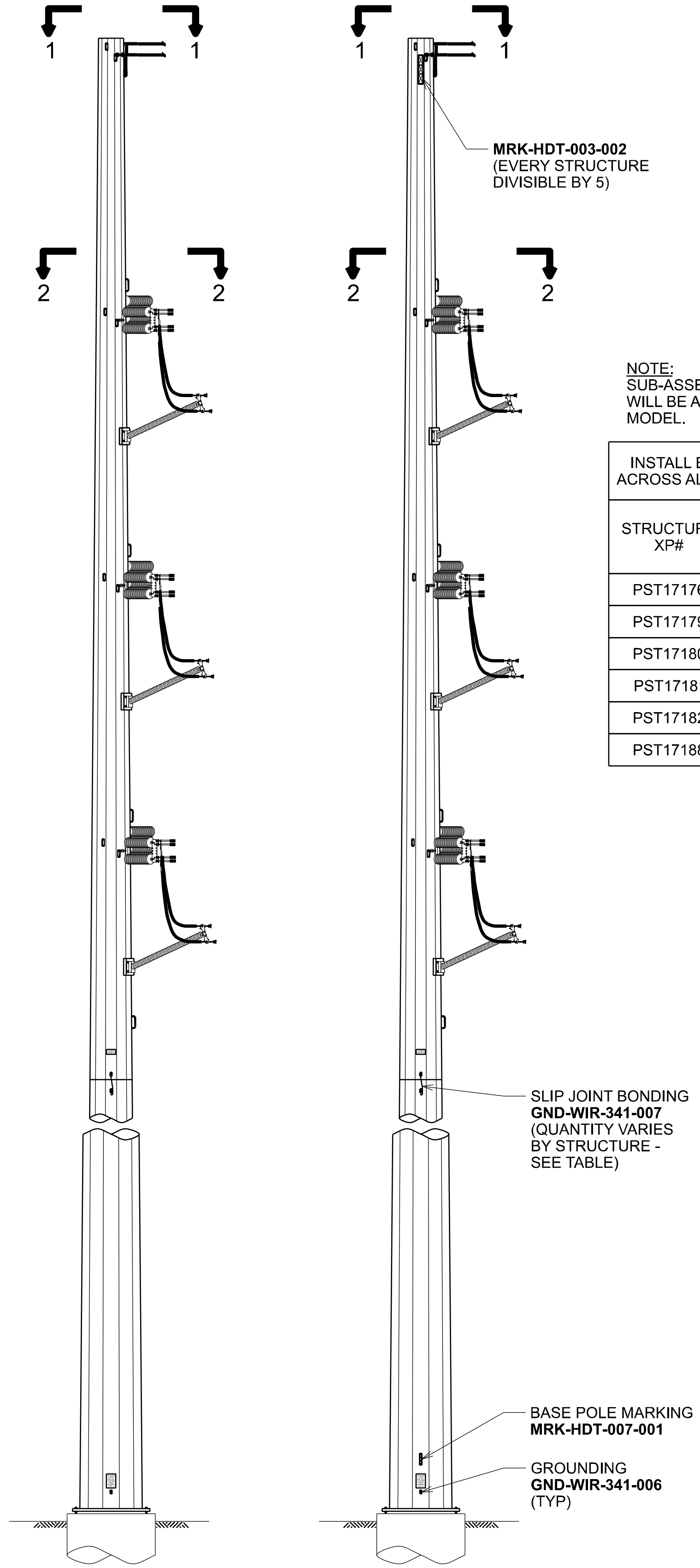
REV	DATE	WBS 4	REVISION DESCRIPTION
0	09/25/2019	B.0000004.021.001.001	IFC - WILMARTH-HUNTLEY - NEW CONSRTUCTION

ISSUED BY ENGINEERING DEPT FOR: CONSTRUCTION

LINE 0967 345 kV
STRUCTURE DRAWING - TANGENT - STEEL - D.C. - SINGLE POLE
TAN TO 2 DEGREE, DAVIT ARM, V-STRING

Xcel Energy® ND-279464-1 SCALE AS NOTED REV 0

4/27/2020 8:03:50 AM



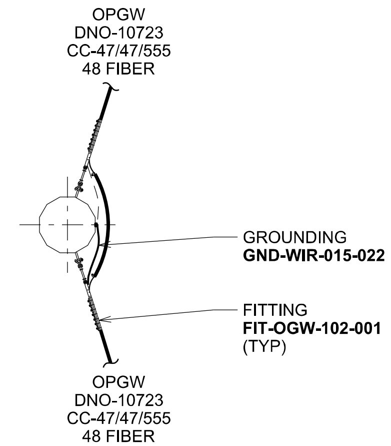
ELEVATION VIEW

STRUCTURE SHOWN IS RIGHT ANGLE CONFIGURATION - ROTATE 180° FOR LEFT ANGLE CONFIGURATION

LINE ANGLE VARIES BY STRUCTURE

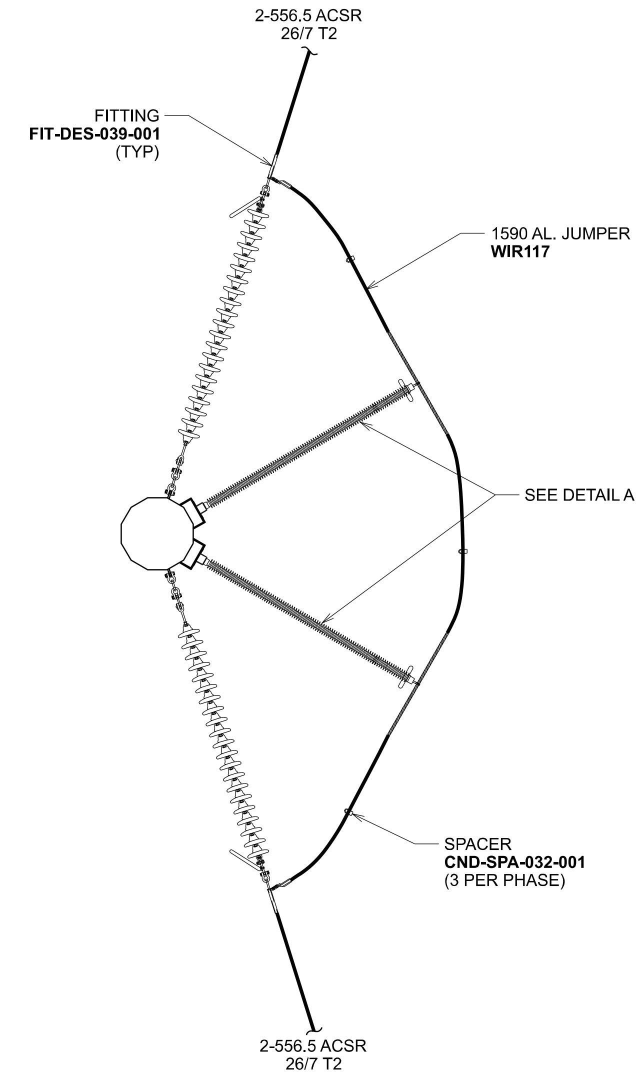
NOTE:
SUB-ASSEMBLY FOR JOINT BONDS WILL BE ADDED TO EACH PLS POLE MODEL.

INSTALL BONDING **GND-WIR-341-007** ACROSS ALL STEEL SHAFT SLIP JOINTS		
STRUCTURE XP#	POLE HEIGHT	TOTAL NUMBER OF SLIP JOINT BONDING REQUIRED
PST17176	130'-0"	2
PST17179	155'-0"	3
PST17180	160'-0"	3
PST17181	165'-0"	3
PST17182	155'-0"	3
PST17188	145'-0"	3



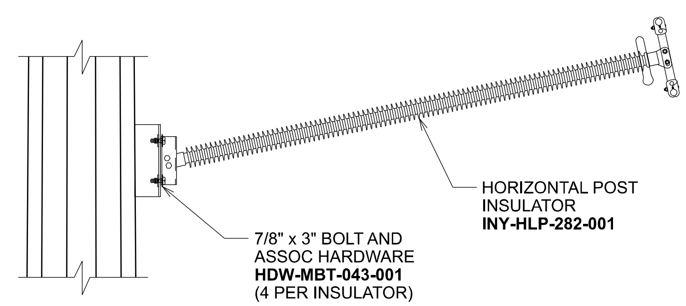
SECTION 1-1

SHIELD WIRE
SCALE: NONE



SECTION 2-2

PHASE
SCALE: NONE



DETAIL A

HORIZONTAL POST INSULATOR
SCALE: NONE

ASSEMBLY
STR ND-279471-1
FOR STEEL POLES
LINE 0967

STL ND-279455-PST17176
STL ND-279455-PST17179
STL ND-279455-PST17180
STL ND-279455-PST17181
LD ND-279425

STL ND-279455-PST17182
LD ND-279426

STL ND-279455-PST17188
LD ND-279431

QTY	SUBASSEMBLIES
9	CND-SPA-032-001
2	FIB-OGW-102-001
6	FIT-DES-039-001
2	GND-WIR-015-022
2	GND-WIR-341-006
48	HDW-MBT-043-001
12	INY-HLP-282-001
1	MRK-HDT-007-001
330	WIR117 - 1590 AL

ASSEMBLY
STR ND-279471-2
FOR STEEL POLES
LINE 0982

QTY	SUBASSEMBLIES
9	CND-SPA-032-001
6	FIT-DES-039-001
330	WIR117 - 1590 AL.

ND-279471-1.DGN

DRAWING REFERENCE

PLAN & PROFILE ________ ND-279505
SUBASSEMBLY INDEX ________ NL-279504

THIS PE SEAL IS ONLY APPLICABLE TO THE CURRENT CONSTRUCTION REVISION

ISSUED BY ENGINEERING DEPT FOR: CONSTRUCTION

LINE 0967 345 kV
STRUCTURE DRAWING - DEADEND - TERMINAL - STEEL - ANGLE
0 TO 95 DEGREE - DOUBLE CIRCUIT - 2-POLE, NO OPGW SPLICE

Xcel Energy® ND-279471-1 SCALE 1/16"=1'-0" REV 0

7/20/2020 11:25:20 AM

REV	DATE	WBS 4	REVISION DESCRIPTION
0	01/13/2020	B.0000004.021.001.001	IFC - WILMARTH-HUNTLEY - NEW CONSRTUCTION

Appendix D

Application Completeness Requirements

Northern States Power Company
Lyon County Generating Station Proposal
MPUC Docket No. E002 / CN-23/212
January 2024

Appendix D: Application Completeness Requirements

Authority	Required Information	Location in Application
Minn. R. 7849.0200, Subp. 4	Cover letter	Cover Letter
Minn. R. 7829.2500, Subp. 2	Brief summary of filing on separate page sufficient to apprise potentially interested parties of its nature and general content	Proposal Summary
Minn. R. 7849.0200, Subp. 2	Title Page and Table of Contents	Application
Minn. R. 7849.0240	Need Summary and Additional Considerations	
Subp. 1	Summary of the major factors that justify the need for the proposed facility	1.2, 1.4, 1.7, 3
Subp. 2	Relationship of the proposed facility to the following socioeconomic considerations:	1.7
A.	Socially beneficial uses of the output of the facility;	1.7
B.	Promotional activities that may have given rise to the demand for the facility; and	1.7
C.	Effects of the facility in inducing future development.	1.7
Minn. R. 7849.0250	Proposed LEGF and Alternatives	
A.	A description of the facility, including:	
(1)	Nominal generating capability of the facility, and discussion of economies of scale on facility size and timing;	Section 4.1; Appendix B, Table B-4
(2)	Description of anticipated operating cycle, including expected annual capacity factor;	Appendix B, Table B-4
(3)	Type of fuel used, including the reason for the choice, its projected availability over the facility's life, and alternate fuels, if any;	1.2, 4.1, 4.2; Appendix B, Table B-2
(4)	Anticipated heat rate of the facility; and	Appendix B, Table B-1
(5)	To the fullest extent known to applicant, the anticipated area(s) the facility could be located;	1.2, 4.1, 6
B.	Discussion of available alternatives, including:	
(1)	Purchased power;	5.3

Authority	Required Information	Location in Application
(2)	Increased efficiency of existing facilities, including transmission lines;	5.6, 5.7
(3)	New transmission lines;	5.7
(4)	New generating facilities of different size or using different energy sources; and	5.4-5.6
(5)	Any reasonable combination of the above;	5
C.	For proposed facility and alternatives discussed in item (B) that could provide electric power to meet the identified need:	
(1)	Capacity cost/kW in current dollars;	Appendix B, Table B-3
(2)	Service life;	4.4; Appendix B, Table B-4
(3)	Estimated average annual availability;	Appendix B, Table B-4
(4)	Fuel costs/kWh in current dollars;	Appendix B, Table B-3
(5)	Variable O&M costs/kWh in current dollars;	Appendix B, Table B-3
(6)	Total cost of a kWh generated in current dollars;	Appendix B, Table B-3
(7)	Estimate of effect on rates systemwide and Minnesota, assuming a test year beginning with in-service date;	Appendix B, Table B-3
(8)	Estimated heat rate; and	Appendix B, Table B-1
(9)	Major assumptions for subitems (1)–(8), including projected escalation rates for fuel and O&M, and project capacity factors;	Appendix B
D.	A map showing applicant's system; and	2.2
E.	Other information about the facility and alternatives relevant to determination of need.	1.4, 3, 4, 5
Minn. R. 7849.0270	Peak Demand and Annual Consumption Forecasts	Appendix A incorporating the 2019 IRP forecast; to be

Authority	Required Information	Location in Application
		supplemented by data and analysis from the 2024-2040 IRP when available
Subp. 1	Peak demand and annual consumption data for applicant's service area and system, indicating when data is not available, historical, or projected;	See above
Subp. 2	The following data for each forecast year:	See above
A.	Annual consumption by ultimate consumers within applicant's Minnesota service area;	See above
B.	Estimates of total ultimate consumers and their annual consumption for each of the following consumer categories:	
(1)	Farm;	See above
(2)	Irrigation and drainage pumping;	See above
(3)	Nonfarm residential;	See above
(4)	Commercial;	See above
(5)	Mining;	See above
(6)	Industrial;	See above
(7)	Street and highway lighting;	See above
(8)	Transportation;	See above
(9)	Other (including municipal water pumping, oil/gas pipeline pumping, military, all other consumers not reported in subitems (1)-(8)); and	See above
(10)	Sum of subitems (1)-(9);	See above
C.	Estimate of demand on applicant's system at time of annual system peak demand, including breakdown of demand into consumer categories in item B;	See above
D.	Applicant's system peak demand by month;	See above
E.	Estimated annual revenue requirement/kWh for system in current dollars; and	See above
F.	Applicant's estimated average system weekday load factor by month;	See above
Subp. 3	Detail of forecast methodology employed, including	
A.	Overall methodological framework that is used;	See above

Authority	Required Information	Location in Application
B.	Specific analytical techniques used, their purpose, and components to which they were applied;	See above
C.	Manner in which specific techniques relate to forecast;	See above
D.	Where statistical techniques have been used:	
(1)	Purpose of technique;	See above
(2)	Typical computations, specifying variables and data; and	See above
(3)	Results of appropriate statistical tests;	See above
E.	Forecast confidence levels/ranges of accuracy for annual peak demand and consumption, and description of their derivation;	See above
F.	Brief analysis of methodology used, including:	
(1)	Strengths and weaknesses;	See above
(2)	Suitability to the system;	See above
(3)	Cost considerations;	See above
(4)	Data requirements;	See above
(5)	Past accuracy; and	See above
(6)	Other significant factors;	See above
G.	Explanation of discrepancies between application's forecast and applicant forecasts in other proceedings;	See above
Subp. 4	Data base used in forecast, including:	
A.	Complete list of all data used in forecast, including a brief description of each and how it was obtained;	See above
B.	Clear identification of any adjustments to raw data to adapt them for use in forecasting, including:	
(1)	Nature of adjustment;	See above
(2)	Reason for adjustment; and	See above
(3)	Magnitude of adjustment	See above
Subp 5	Essential forecast assumptions made regarding:	
A.	Availability of alternate sources of energy;	See above
B.	Expected conversion from other fuels to electricity or vice versa;	See above
C.	Future electricity prices in applicant's system and their effect on system demand;	See above
D.	Subpart 2 data that is not available historically nor created by applicant for forecast;	See above
E.	Effect of conservation programs on long-term	See above

Authority	Required Information	Location in Application
	demand; and	
F.	Any factor considered in preparing forecast;	See above
Subp. 6	Coordination of forecasts	
A.	Description of extent applicant coordinates load forecasts with other systems; and	See above
B.	Description of forecast coordination, including problems experienced.	See above
Minn. R. 7849.0280	System Capacity Description	Appendix A incorporating the 2019 IRP forecast; to be supplemented by data and analysis from the 2024-2040 IRP when available
A.	Brief discussion of power planning programs applied to applicant's system;	See above
B.	Applicant's seasonal firm purchases/firm sales for each utility involved in each transaction for each forecast year;	See above
C.	Applicant's seasonal firm participation purchases/sales for each utility involved in each transaction for each forecast year;	See above
D.	Load and generation capacity data for sub-items below for summer and winter seasons for each forecast year, including anticipated purchases, sales, and capacity retirements/additions:	
(1)	Seasonal system demand;	See above
(2)	Annual system demand;	See above
(3)	Total seasonal firm purchases;	See above
(4)	Total seasonal firm sales;	See above
(5)	Seasonal adjusted net demand;	See above
(6)	Annual adjusted net demand;	See above
(7)	Net generating capacity;	See above

Authority	Required Information	Location in Application
(8)	Total participation purchases;	See above
(9)	Total participation sales;	See above
(10)	Adjusted net capability;	See above
(11)	Net reserve capacity obligation;	See above
(12)	Total firm capacity obligation; and	See above
(13)	Surplus or deficit capacity;	See above
E.	Load and generation capacity data requested in item D/sub-items (1)-(13) for summer and winter seasons for each forecast year subsequent to the year of application, including purchases, sales, and generating capability contingent on the proposed facility;	See above
F.	Load and generation capacity data requested in item D/sub-items (1)-(13) for summer and winter seasons for each forecast year subsequent to the year of application, including all projected purchases, sales, and generating capability;	See above
G.	List of proposed additions/retirements in net generating capability for each forecast year subsequent to the year of application;	See above
H.	Graph showing monthly adjusted net demand, monthly adjusted net capability, and difference between adjusted net capability and actual, planned, or estimated maintenance outages of generation/ transmission for specified time periods; and	See above
I.	Discussion of method and appropriateness of determining system reserve margins.	See above
Minn. R. 7849.0290	Conservation Programs	
A.	Name of committee, department, individual responsible for applicant's energy conservation/efficiency programs, including load management;	Appendix A
B.	List of applicant's conservation/efficiency goals and objectives;	Appendix A
C.	Description of specific energy conservation/efficiency programs considered, a list of those implemented, and reasons why other	Appendix A

Authority	Required Information	Location in Application
	programs have not been implemented;	
D.	Description of major energy conservation/efficiency accomplishments by applicant;	Appendix A
E.	Description of applicant's energy conservation/efficiency plans through the forecast years; and	Appendix A
F.	Quantification of how energy conservation/efficiency programs affect the 7849.0270, subp. 2 forecast, a list of total program costs, and discussion of expected program effects in reducing need for new generation and transmission.	Appendix A
Minn. R. 7849.0300	Consequence of Delay	4.7
Minn. R. 7849.0310	Required Environmental Information	6
Minn. R. 7849.0320	Information for Generating Facilities and Alternatives	
A.	Estimated land requirements for facility, water storage, cooling system, and solid waste storages;	6.1, 6.5, 6.6; Appendix B, Tables B-2, B-4
B.	Estimated amount of vehicular, rail, and barge traffic due to construction and operation;	6.2.3
C.	For fossil-fueled facilities:	
(1)	Expected regional sources of fuel;	4.2; Appendix B, Table B-2
(2)	Typical hourly and annual fuel requirement ;	Appendix B, Table B-2
(3)	Expected rate of heat input in Btu/hour ;	Appendix B, Tables, B-1b, B-2
(4)	Typical range of fuel's heat value and typical average of fuel's heat value; and	Appendix B, Tables B-1b, B-2
(5)	Typical ranges of sulfur, ash, and moisture content of fuel;	Appendix B, Table B-2
D.	For fossil-fueled facilities:	

Authority	Required Information	Location in Application
(1)	Estimated range of emissions of sulfur dioxide, nitrogen oxides, and particulates in pounds/hour; and	6.7
(2)	Estimated range of maximum contributions to 24-hr ground level concentrations of sulfur dioxide, nitrogen oxides, and particulates in micrograms per cubic meter;	6.7, Table 6.4
E.	Water use by the facility for alternate cooling system, including:	
(1)	Estimated maximum use, including groundwater pumping rate in gallons/minute and surface water appropriation in cubit feet/second;	6.5; Appendix B, Table B-4
(2)	Estimated groundwater appropriation in million gallons/year; and	Appendix B, Table B-4
(3)	Annual consumption in acre-feet;	Appendix B, Table B-4
F.	Potential sources/types of discharges to water;	6.5
G.	Radioactive releases, including:	6.6
(1)	For nuclear facilities, typical types/amounts of radionuclides released in curies/year; rate and	N/A
(2)	For fossil-fueled facilities, estimated range of radioactivity released in curies per year;	N/A
H.	Potential types/quantities of solid wastes produced in tons/year;	6.6
I.	Potential sources/types of audible noise;	6.2.2
J.	Estimated work force required for construction and operation; and	Appendix B, Table B-3
K.	Minimum number/size of transmission facilities required for reliable outlet.	4.3
Minn. R. 7849.0340	No-Facility Alternative	5.2
IRP Order	Supplementary Data Required for Alternative Providers	
A.	Developer experience and qualifications.	N/A
B.	Pricing of the proposal, including but not limited to the following:	
1	The term;	
2	In-service date;	

Authority	Required Information	Location in Application
3	Contract capacity;	
4	Capacity payment;	
5	Fixed operations and maintenance payment;	
6	Variable operations and maintenance payment;	
7	Fuel payment; and	
8	Tax-related payments and other costs.	
C.	Scheduling provisions, including but not limited to:	
1	Planned maintenance;	
2	Expected minimum load;	
3	Ramp rates; and	
4	Limitations on operations.	
D.	Discussion of the guaranteed performance factors, such as construction costs, unit completion, availability, and efficiency.	
E.	Any other key contract terms the provider requires.	
800 FD Order	Supplementary Data Required for All Providers	
Metric 32	Provide a climate change analysis of the proposal consistent with the Minnesota Environmental Quality Board's environmental assessment worksheet guidance for developing a carbon footprint and incorporating climate adaptation and resilience.	6.8
Metric 32	Identifying whether the proposal is located in an environmental justice area using census criteria in Minnesota Statute 216B.1691, subd. 1(e).	6.9.2
Metric 61	Information necessary for consideration of Energy Justice factors:	
	The socioeconomic factors of a project's location;	6.9.3
	The involvement of local government, community organizations and, where relevant, Tribal Nations;	6.9.3
	The estimated local tax revenue it will produce;	6.9.3
	The temporary and permanent jobs it will create;	6.9.3
	The commitment to the use of diverse suppliers, as demonstrated by a history of use on recent projects; and	6.9.3
	The payment of prevailing wages, and workforce training opportunities.	6.9.3
Metric 32	Minn. R. 7849.1500 Subp. 2: Impacts of Power	

Authority	Required Information	Location in Application
	Plants:	
A.	The anticipated emissions of the following pollutants expressed as an annual amount at the maximum rated capacity of the project and as an amount produced per kilowatt hour and the calculations performed to determine the emissions: sulfur dioxide, nitrogen oxides, carbon dioxide, mercury, and particulate matter, including particulate matter under 2.5 microns in diameter;	6.10, 6.7, 6.8
B.	The anticipated emissions of any hazardous air pollutants and volatile organic compounds;	6.10, 6.7, 6.8
C.	The anticipated contribution of the project to impairment of visibility within a 50-mile radius of the plant;	6.10
D.	The anticipated contribution of the project to the formation of ozone expressed as reactive organic gases. Reactive organic gases are chemicals that are precursors necessary to the formation of ground-level ozone;	6.10
E.	The availability of the source of fuel for the project, the amount required annually, and the method of transportation to get the fuel to the plant;	6.10, 4.2, Appendix B, Table B-2
F.	Associated facilities required to transmit the electricity to customers;	6.10, 1.1.1, 4.1, 4.2
G.	The anticipated amount of water that will be appropriated to operate the plant and the source of the water if known;	6.10, 6.5
H.	The potential wastewater streams and the types of discharges associated with such a project including potential impacts of a thermal discharge;	6.10, 6.6
I	The types and amounts of solid and hazardous wastes generated by such a project, including an analysis of what contaminants may be found in the ash and where the ash might be sent for disposal or reuse; and	6.10, 6.6
J.	The anticipated noise impacts of a project, including the distance to the closest receptor where state noise standards can still be met.	6.10, 6.2.2

Authority	Required Information	Location in Application
Minn. Stat. §§ 216B.2422, subd. 4; 216B.243, subd. 3a	Whether the applicant for a project generating nonrenewable energy has demonstrated that the project is less expensive than one generating renewable energy or is otherwise in the public interest.	1.2, 1.6, 1.7, 4.1, 4.2, 5; Appendix B
Minn. Stat. § 216B.243, subd. 3(10)	Whether the applicant is in compliance with Minnesota's carbon-free and renewable energy standards, including identifying transmission projects necessary to meet those standards.	3.2
Minn. Stat. § 216B.2426	Whether the applicant has considered the opportunities for installation of distributed generation.	5.4.1
Minn. Stat. § 216B.243, subd. 3(12)	Whether an applicant proposing a nonrenewable energy generating plant has assessed the risk of environmental costs and regulation over the expected useful life of the plant.	1, 4, 5, 6.7, 6.8; Appendix B
Minn. Stat. § 216B.1694, subd. (2)(a)(4)	Whether the applicant has considered an innovative energy project as a supply option before expanding a fossil-fuel-fired generation facility or entering into a 5+-year purchased power agreement.	5.3, 5.7

Appendix D-2: Information related to resources attributes to be evaluated in Phase 1

ID	Attribute Category	Metric	Location in Application
1	Capacity	Nameplate capacity of commercially operable project is > 5 MWac.	1.2
2	Capacity	Commercially operable project must be transmission-interconnected.	4.3
3	Capacity	Commercially operable project must interconnect in MISO Zone 1 with uninterrupted interconnection path to MISO Load.	1.2, 4.1, 4.3
4	Capacity	Must achieve COD by 12/31/2028	4.6
5	Capacity	*For Physical Assets:* Must be able to operate commercially at the highest 0.2 percentile hourly temperature from Jan 1, 2000 until the date the temperature is calculated, using the NOAA NCEI station nearest to the generator, and for cold weather, the smallest of the 50 year regional extreme cold temperature as defined by the NOAA NCEI station nearest to the generator or the Extreme Cold Weather Temperature defined in NERC EOP-012, whichever is colder. *For Demand Response Assets:* Capable of commercial operation at equivalent analog criteria.	4.1; Appendix B
6	Capacity	For Existing Projects: Minimum remaining operational life or PPA contract term of 10 years after COD of contract selected in this competitive resource acquisition.	N/A

ID	Attribute Category	Metric	Location in Application
7	Capacity	For New Projects Only: Minimum design life or PPA contract term of 10 years	1.2, 4.1
8	Capacity	For Proposals containing a BESS Project: Must provide estimate of capacity degradation rate via warranty or independent evaluation.	N/A
9	Capacity	For Power Purchase Agreements Only: O&M plan must be provided and must be sufficient for proposed contract term	N/A
10	Capacity	For Build-Transfer Projects Only: Compliance with Company Technical Specifications	N/A
59	Bidder Financial Strength & Experience	Bidder has financial viability & demonstrated experience on same type of project.	2.1, 2.2
60	Energy Justice	Does the proposal utilize union labor?	6.9.3