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August 29, 2023

VIA ELECTRONIC MAIL AND
FEDERAL EXPRESS

Mr. Steven M. Kahl
Executive Director
North Dakota Public Service Commission
State Capitol Building, Department 408
600 East Boulevard
Bismarck, ND 58505-0480

Re: NORTHERN STATES POWER COMPANY
ADVANCED PRUDENCE - BROOKINGS COUNTY TO LYON COUNTY AND HELENA TO HAMPTON 345 KV SECOND CIRCUIT APPLICATION
CASE NO. PU-23-____

Dear Mr. Kahl:

Northern States Power Company, doing business as Xcel Energy (the Company), respectfully submits this Application for an Advanced Determination of Prudence (ADP) to the North Dakota Public Service Commission (Commission) to install a second-circuit on the Brookings County – Lyon County and Helena – Hampton segments of the Brookings transmission line in eastern South Dakota and southern Minnesota (Project).

The Company's Application and supporting affidavits contain trade secret information. In accordance with Section 69-02-09-02 of the North Dakota Administrative Code (N.D.A.C.), an Application for Trade Secret Protection is being provided along with a single copy of the trade secret version of the Application and supporting affidavits in a sealed envelope marked **PROTECTED INFORMATION – PRIVATE**.

Consistent with N.D.A.C § 69-02-02-04, an original and seven copies of the public version of our Application are also being provided, along with Affidavits of Mr. Jason Standing and Mr. Tony Wendland supporting the Company's Application. The Company is providing affidavits in lieu of prefiled direct testimony to support the Application. The Company can provide prefiled direct testimony if requested by the Commission.

The Company provided the $175,000 filing fee required by N.D.C.C. § 49-05-16(1)(b) under separate cover.

Please contact me at (612) 492-6129 or simpser.zev@dorsey.com if you have any questions regarding this filing.

Respectfully submitted,

DORSEY & WHITNEY LLP

ZEV SIMPSER

ZS:bb

Enclosures

cc: Via Email – Public Version Only:
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BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF NORTH DAKOTA

NORTHERN STATES POWER COMPANY ADVANCE PRUDENCE – BROOKINGS COUNTY TO LYON COUNTY AND HELENA TO HAMPTON 345 KV SECOND CIRCUIT APPLICATION	CASE NO. PU-23-_____

APPLICATION FOR ADVANCE DETERMINATION OF PRUDENCE

I. INTRODUCTION

Northern States Power Company, doing business as Xcel Energy (NSP, Xcel Energy, or the Company), respectfully submits to the North Dakota Public Service Commission (Commission) this Application for an Advance Determination of Prudence (ADP) for the Brookings County – Lyon County Second Circuit Project and Helena – Hampton Second-Circuit Project (collectively, the Brookings County – Lyon County Second Circuit Project and the Helena – Hampton Second Circuit Project are referred to as the Project or Brookings Second-Circuit Project).

The Project is prudent because it will reduce energy costs by expanding transmission capacity in the region. Currently, there is insufficient transmission capacity to efficiently transmit low-cost energy generated in South Dakota, North Dakota, and Minnesota. As a result, the cost of electricity increases because electricity must come from higher marginal cost generators in areas without transmission constraints. These higher costs, and the resulting inefficiencies in the wholesale energy market, increase costs for customers. These limitations are projected to worsen over the next 10 years as more generators come online in this area. The Project is needed to help expand transmission capacity in the area served by the Project. The Project is expected to increase access to low marginal cost generation, provide economic benefits, and strengthen the regional grid. Xcel Energy estimates that the Project would provide Company-specific benefits of $334.83 million in production-cost savings and other quantifiable economic benefits on a present-value basis over the 63-year book life of the Project.

The Project involves installing a second 345 kV circuit on double-circuit-capable structures installed when the Brookings County – Hampton 345 kV transmission line was originally constructed (Original Brookings Line). The Original Brookings Line is owned by Central Minnesota Municipal Power Agency, Great River Energy, NSP, Otter Tail Power Company (Otter Tail), and Western Minnesota Municipal Power Agency (CapX2020 Brookings Owners). The Project will also require reconfiguring certain lines near substations, mostly within existing easements. As part of the Project, the Company will also upgrade the Brookings County, Lyon County, Helena, and Hampton substations with new 345 kV breakers. The Project will require relay setting changes to the Steep Bank Lake and Hawks Nest Lake substations. Finally, the Project will require the construction of eight new poles near Castle Rock, Minnesota, to maintain the transmission line's low profile near an airport after the second circuit is installed.

Given the advantages of the Project, including substantial cost savings, the Company requests that the Commission grant an ADP for the Project.

The remainder of this Application addresses the following:

- Compliance Matters;
- Project Description and Purpose;
- Economic Analysis; and
- Prudence of the Project

II. COMPLIANCE MATTERS

A. Description of Applicant

NSP is a Minnesota corporation duly authorized to conduct business in the State of North Dakota as a foreign corporation. NSP conducts business in the State of North Dakota as a public utility subject to the jurisdiction and regulation of the Commission pursuant to Title 49 of the North Dakota Century Code (N.D.C.C.). The name and address of NSP is:

Northern States Power Company, a Minnesota corporation
414 Nicollet Mall
Minneapolis, Minnesota 55401

The Company also operates in North Dakota from the following address:

Northern States Power Company
2302 Great Northern Drive
Fargo, North Dakota 58102

The Company's Certificate of Incorporation with amendments and Certificate of Authority were filed with the Commission on September 30, 2009, and October 12, 2009, respectively, in Case No. PU-09-664. Current Certificates of Good Standing issued by the North Dakota and Minnesota Secretaries of State were filed in the same case on January 10, 2023, and are incorporated herein by reference.

Xcel Energy has service territory in five upper Midwest states including North Dakota. The Company presently serves approximately 94,500 retail electric customers in and around Fargo, Grand Forks, and Minot, North Dakota, and owns approximately 1,450 conductor miles of transmission and 3,810 conductor miles of electric distribution lines in North Dakota.

B. Communication and Service

The Company respectfully requests that the following persons be placed on the Commission's official service list for all official communications in this case:

Alex J. Nisbet
Regulatory Policy Specialist
Xcel Energy
2302 Great Northern Drive
Fargo, North Dakota 58102
Alex.J.Nisbet@xcelenergy.com

Christine Schwartz
Records Administrator
Xcel Energy
414 Nicollet Mall, 401 – 7th Floor
Minneapolis, Minnesota 55401
regulatory.records@xcelenergy.com

C. Standard of Review

North Dakota Century Code section 49-05-16(1)(d) authorizes the Commission to issue an ADP if the Commission "determines that the resource addition is prudent." This standard is similar to the "honestly and prudently invested" standard that the Commission uses for ratemaking.[1] The general prudence standard calls for determining whether the utility action was reasonable at the time the utility took the action under all relevant circumstances.[2] Under Section 49-05-16(1), the Commission may issue an order approving the prudence of a proposed project if four conditions are met:

> a. The public utility files with its application a projection of costs to the date of the anticipated commercial operation of the resource addition;
>
> b. The public utility files with its application a fee in the amount of one hundred seventy-five thousand dollars;
>
> c. The commission provides notice and holds a hearing, if appropriate, in accordance with section 49-02-02; and
>
> d. The commission determines that the resource addition is prudent. For facilities located or to be located in this state the commission, in

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[1] *See* N.D.C.C. § 49-06-02.

[2] *See* Charles F. Philips, Jr., *The Regulation of Public Utilities – Theory and Practice* at 292 (Public Utility Reports 1988); *see also* David J. Muchow & William A. Mogel, *Energy Law and Transactions* at § 4.02[3][b] (2009).

> determining whether the resource addition is prudent, shall consider the benefits of having the resource addition located in this state.

D. Authority for Relief Requested

North Dakota Century Code section 49-05-16 allows a public utility, at the utility's discretion, to seek an ADP from the Commission for any intended resource addition. The statute defines a "resource addition" as "construction, modification, purchase, or lease of an energy conversion facility, renewable energy facility, demand response system, transmission facility, or a contract to acquire energy, capacity or demand response for the purpose of providing electric service." The Project fits within that definition, as it is a transmission facility.

In the Settlement Agreement in the Company's 2007 rate case, Case No. PU-07-776, the Company agreed to file an application for an ADP for the acquisition of transmission facilities that are at least 50 miles long.[3] This commitment was further refined in Case No. PU-12-59, in which NSP committed to filing ADP applications for "the types of resource additions contemplated in the 2007 rate case settlement" within 14 days of seeking similar approvals from the Minnesota Public Utilities Commission (MPUC).[4]

The Company filed an Application for a Certificate of Need (CON) for the Project with the MPUC on August 15, 2023. Accordingly, the Company is submitting this Application within 14 days, as required by its commitment made in Case No. PU-12-59, along with supporting affidavits.

III. PROJECT DESCRIPTION AND PURPOSE

In this section, the Company: (1) provides an overview of the electrical system (2) describes the Project facilities, (3) provides the Project ownership, (4) discusses Project background and development, (4) provides the results of the Company's reliability analysis, (5) provides the estimated Project costs, and (6) lays out the current Project schedule.

A. Electrical System Overview

To provide context for the Project, this section provides a high-level overview of the electrical system and describes where transmission projects, like the Brookings Second-Circuit Project, fit into that system.

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[3] *N. States Power Co. Elec. Rate Increase Application*, Case No. PU-07-776, ORDER ADOPTING SETTLEMENT AGREEMENT,Settlement Agreement at 6 (Dec. 31, 2008).

[4] *N. States Power Co. Advance Prudence – Geronimo Wind Application*, Case No. PU-12-59, LETTER OF COMMITMENT (Nov. 5, 2012).

1. Electrical System Overview

The electric grid is generally broken down into two systems: the transmission system and the distribution system.

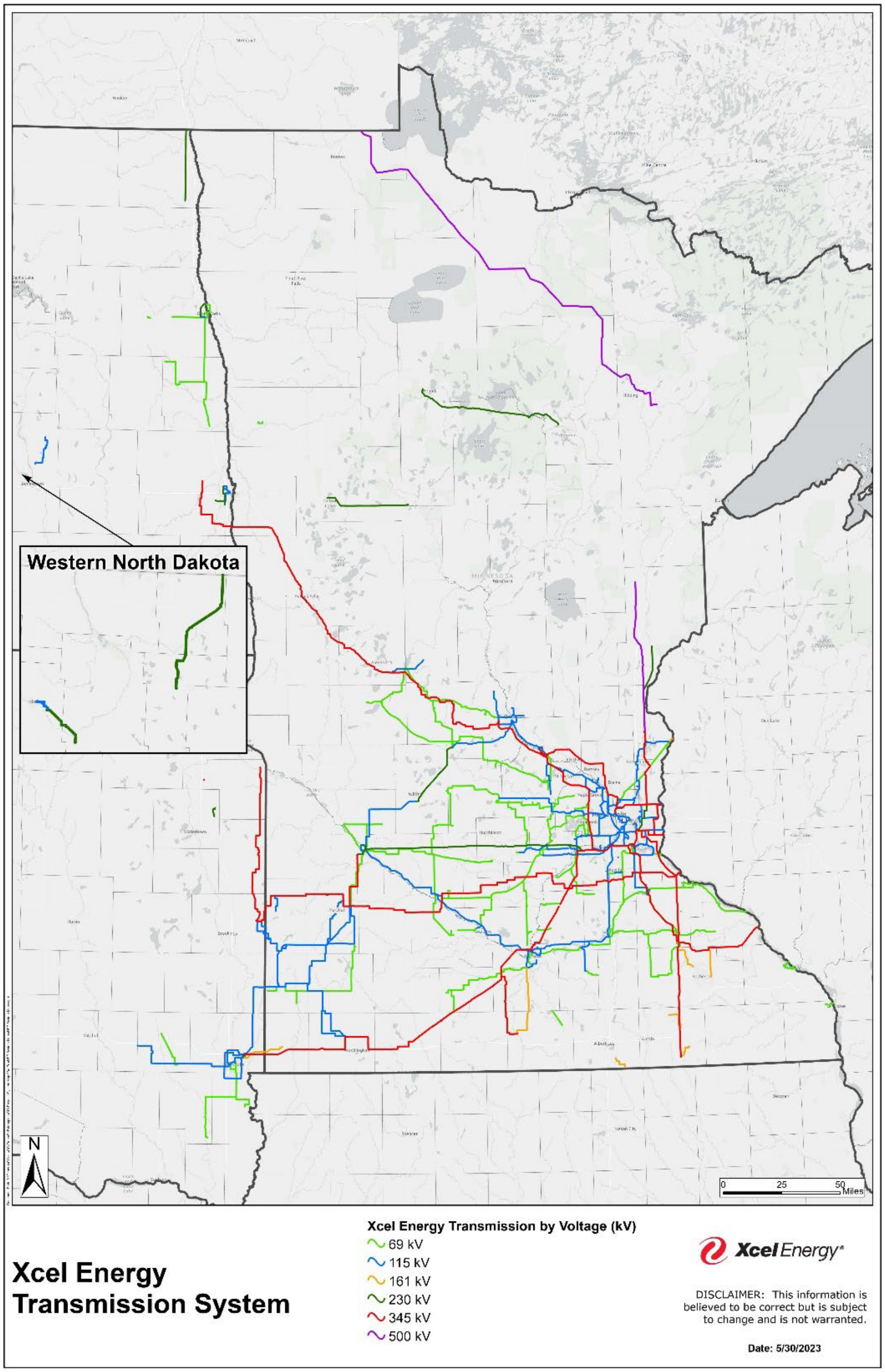
The transmission system is made up of high-voltage transmission lines and bulk transformers at 100 kV and above. Transmission lines, in turn, are made up of conductors, which complete a three-phase circuit and are usually accompanied by a shield wire that protects the line from lightning strikes. The transmission system is designed to withstand the outage of a single transmission line without major disruption to the overall power supply.

Substations are also a part of the transmission system and contain high-voltage electric equipment to monitor, regulate, and transmit electricity. Transmission substations allow transmission lines to connect with one another.

Substation configuration depends on the project and anticipated future needs based on the physical characteristics of the site, such as shape, elevation, above and below ground geographical characteristics, and proximity of the site to transmission lines. The configuration of a substation may change over time to accommodate future load growth or electric system needs.

Xcel Energy’s transmission system in Minnesota, North Dakota, and South Dakota is depicted below in **Figure 1**.

Figure 1: Xcel Energy's Transmission System in Minnesota, North Dakota, and South Dakota[5]



[5] Portions of the lines depicted above are transmission facilities that Xcel Energy owns with other utilities.

The transmission system is used to transport power relatively long distances from the generation source to the distribution system. Electric energy is generated at a specific voltage and frequency. Typically, the voltage of electricity generated in a power plant is increased (stepped-up) by transformers installed close to the generating plant.

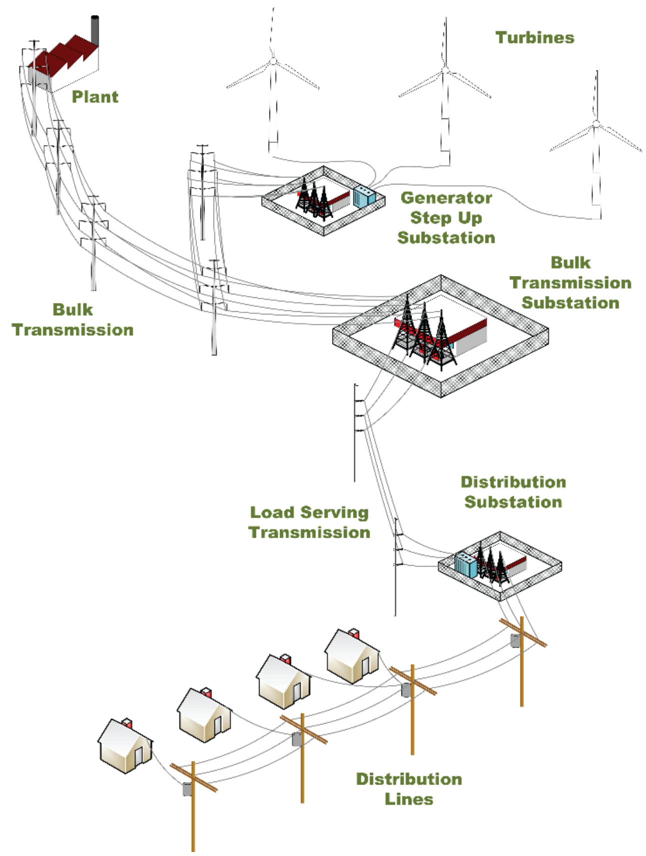
Stepping-up the voltage between the generator and transmission system reduces electrical losses on the system, allowing more of the energy generated to reach consumers. Electricity is typically transported over transmission lines at voltages in excess of 100 kV (e.g., 115 kV, 230 kV, 345 kV). As voltage increases, electric current decreases assuming the same amount of power flowing through a transmission line. Due to the relationship between power losses, electrical resistance, and electrical current, reducing current along a transmission line has a much greater impact on reducing power losses than reducing resistance of a power line.

Once the electricity reaches the distribution system, the transmission voltage (e.g., 100 kV and higher) is reduced (stepped-down) by transformers at a distribution substation facility to voltages appropriate for distribution to end use customers, typically below 69 kV.

The electricity is then further transformed (stepped down) and distributed at distribution "primary" voltages (e.g., 13.8 kV) within communities by the distribution system, which delivers power for individual customer use to the end location where it is stepped-down further to, most commonly, 240 V or 120 V.

A diagram showing the transfer of electricity from generator to consumer is shown below in **Figure 2**.

Figure 2: Electrical System



Note **Figure 2** is an artistic portrayal of an electrical system and is not an actual representation of all electrical-system components.

B. Facility Description

The Project involves upgrades to both a high-voltage transmission line and substations. NSP proposes to install a second circuit on an unused set of davit arms on the Brookings County – Lyon County portion (Western Segment) and the Helena – Hampton portion (Eastern Segment) of the Original Brookings Line. These davit arms coupled with increased strength of the towers made the Original Brookings Line double-circuit capable, accommodating the future installation of a second circuit. The total length of the Project is approximately 98.5 miles.[6] The Western Segment extends approximately 59.5 miles from the Brookings County Substation near White, South Dakota, to the Lyon County Substation near Milroy, Minnesota.[7] The Eastern Segment extends 39 miles from Helena Substation near New Prague, Minnesota, to the Hampton Substation near Hampton, Minnesota.[8]

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[6] Affidavit of Mr. Tony Wendland, Ex. 1 (TW-1) (Wendland Aff.) ¶ 24.
[7] Wendland Aff. ¶ 25.
[8] Wendland Aff. ¶ 26.

The Western Segment will require reconfiguring an existing line at the Steep Bank Lake Substation, northeast of Hendricks, Minnesota, to avoid the second circuit crossing the existing transmission line.[9] This reconfiguration will involve adding one additional structure outside of the Steep Bank Lake Substation.[10] Due to this reconfiguration, the Company will also need to make changes to the relay settings at both the Steep Bank Lake and Hawks Nest Substations.[11]

The Eastern Segment will require routing the second circuit around the Chub Lake Substation, northeast of Elko-New Market.[12] The Company will construct two new dead-end structures on foundations on the south side of the Chub Lake substation to avoid the second circuit having to go over the top of the Chub Lake Substation.[13]

As part of the Project, the Company will also upgrade the Brookings County, Lyon County, Helena, and Hampton substations with new 345 kV breakers.[14] The Company will install one new breaker at the Brookings County Substation, four new breakers at the Lyon County Substation, one new breaker at the Helena Substation, and four new breakers at the Hampton Substation.[15] At the Lyon County and Hampton substations, the Company will remove the current ring-bus configuration and construct a breaker-and-a-half configuration.[16] This reconfiguration allows improved operational flexibility by reducing line outages caused by breaker maintenance or failure.[17]

Figure 3 below depicts the Project, including substations.

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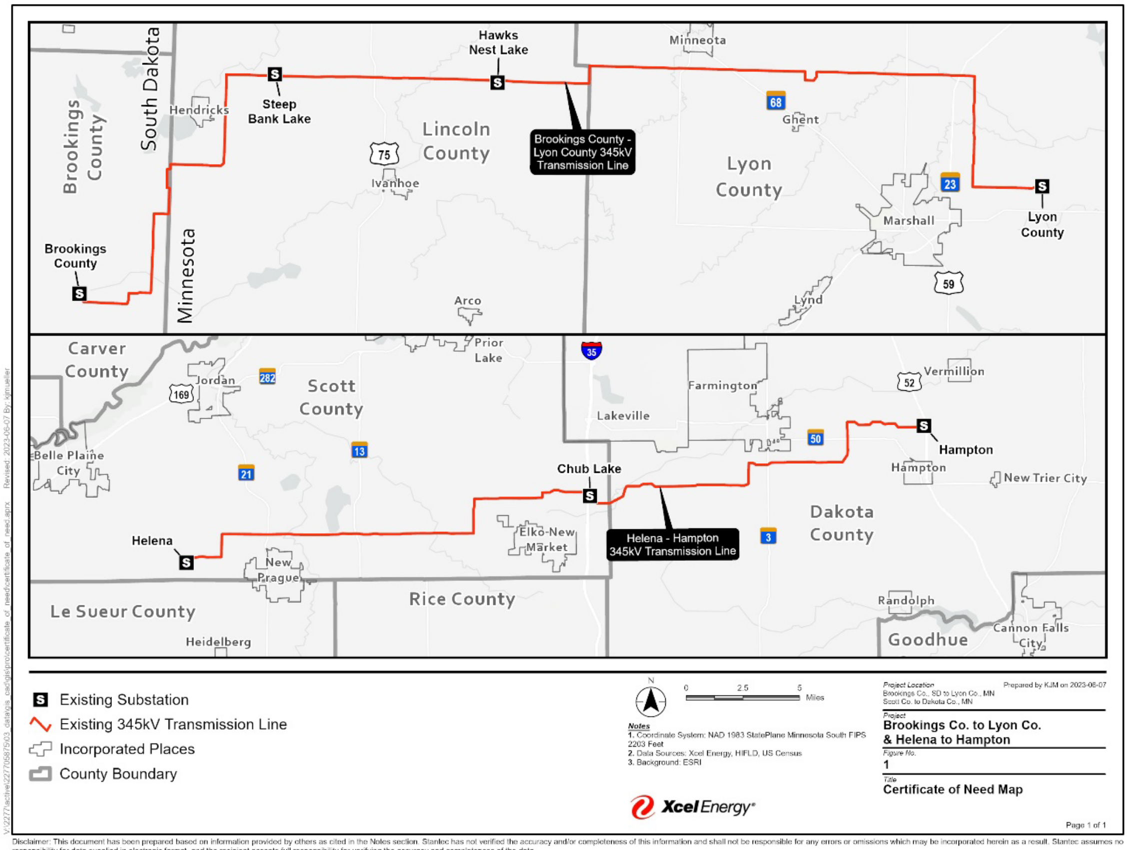
[9] Wendland Aff. ¶ 31.
[10] Wendland Aff. ¶ 31.
[11] Wendland Aff. ¶ 32.
[12] Wendland Aff. ¶ 33.
[13] Wendland Aff. ¶ 33.
[14] Wendland Aff. ¶ 35.
[15] Wendland Aff. ¶ 36.
[16] Wendland Aff. ¶ 37.
[17] Wendland Aff. ¶ 37.

Figure 3: Project Facilities



C. Project Ownership

Xcel Energy is the sole applicant and currently the sole owner for the Project. The Applicable terms of the Brookings Project Owners' Project Participation Agreement (Agreement) specifies that both the Western Segment and the Eastern Segment of the Brookings Second-Circuit Project are separate "Upgrades," under the Agreement. As Upgrades, Xcel Energy has the right to pursue the Project without consent from other CapX2020 Brookings Owners of the Original Brookings Line's Management Committee. However, the other CapX2020 Brookings Owners have the right to participate in each of the Western Segment and the Eastern Segment, respectively, of the Project. Under the Agreement, Xcel Energy must offer, and formally notify the other CapX2020 Brookings Owners of, the option to participate in the Western Segment and the Eastern Segment Upgrades, respectively, of the Project. Xcel Energy plans to send these separate formal notices for the Western Segment in the second half of 2023 and the formal notice for the Eastern Segment in the second half of 2024. Additionally, before energizing the Eastern and Western Segments of the Project, the Owners' Management Committee under the Agreement will determine whether one or both of the Western and Eastern Segments will be incorporated as part of the "Facilities" under the Agreement. If the Management Committee determines that one or both of the Segments will become part of the "Facilities" under the Agreement, the applicable segment will be subject to and governed by the Agreement and certain associated Agreements. If any of the other CapX2020 Brookings Owners elect to participate in the Western Segment or the Eastern Segment, the change of ownership will not occur until the respective segment is energized.

D. Project Background and Need

This section describes the history of the Original Brookings Line and information regarding the development of the Brookings Second-Circuit Project.

1. Project Background

On October 2, 2009, NSP and co-owner Otter Tail (collectively, Original Brookings Line Applicants) applied for an ADP in North Dakota for the CapX2020 Group 1 Transmission Projects, including the Original Brookings Line.[18] In their Joint Application, the Original Brookings Line Applicants noted that both the Western and Eastern Segments of the Original Brookings Line would be constructed with double-circuit capable structures.[19] They also stated that the both circuits would be installed during initial construction of the Original Brookings Line between the Lyon County Substation and the Helena Substation.[20] The Joint Application explained that initially the owners of the Original Brookings Line planned only to construct the Lyon County – Helena segment as double circuit, with the remainder only being capable of holding a single circuit.[21] But, the Original Applicants continued, "[a]s a result of the long-term planning horizon and Applicants' desire to ensure the transmission system continues to meet customer requirements in the future, Applicants decided to construct [three of the projects, including the Western and Eastern Segments of the Original Brookings Line,] using double-circuit capable structures."[22] The Original Applicants explained that a double-circuit configuration means the segments would be built on structures and on right-of-way sufficient to accommodate a second 345 kV circuit in the future. They

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[18] *N. States Power Co. & Otter Tail Power Co. Advance Prudence – CapX2020 Group 1 Transmission Projects Application*, Case Nos. PU-09-676 & -678, JOINT APPLICATION FOR ADVANCE DETERMINATION OF PRUDENCE (Oct. 5, 2009); *see also* Wendland Aff. ¶ 9. The other projects included in the CapX2020 Group 1 Transmission Projects were separate transmission lines from Fargo, North Dakota, to the Twin Cities; the Twin Cities to La Crosse, Wisconsin; and Bemidji, Minnesota, to Grand Rapids, Minnesota.

[19] Case Nos. PU-09-676 & -678, JOINT APPLICATION FOR ADVANCE DETERMINATION OF PRUDENCE at 9 (Oct. 5, 2009); Wendland Aff. ¶ 10.

[20] Case Nos. PU-09-676 & -678, JOINT APPLICATION FOR ADVANCE DETERMINATION OF PRUDENCE at 9 (Oct. 5, 2009); Wendland Aff. ¶ 10.

[21] Case Nos. PU-09-676 & -678, JOINT APPLICATION FOR ADVANCE DETERMINATION OF PRUDENCE at 12 (Oct. 5, 2009).

[22] *Id.* at 12-13.

noted in the Joint Application that the second circuit would "be strung when circumstances warrant and all necessary regulatory approvals are received."[23] The Original Applicants further explained that the double-circuit configuration "ensures that these projects will be available for future expansion (via deployment of the second circuit) when that additional capacity is deemed to be needed by the Commission."[24]

The Original Applicants and Advocacy Staff reached a settlement agreement supporting issuance of an ADP subject to resolution of outstanding cost-allocation issues.[25] The Commission accepted the settlement agreement subject to determination of continued prudence once outstanding cost-allocation issues were resolved.[26] After the outstanding issues were resolved, the Commission determined NSP's and Otter Tail's investments in the Original Brookings Line continued to be prudent.[27]

The CapX2020 Brookings Owners subsequently constructed the Original Brookings Line, energizing the final segment in 2015.[28] As anticipated, over the course of the next eight years, congestion continued to increase significantly in the area served by the Project.[29]

2. Project Development

The Company developed the Project in direct response to the recent increases in congestion. The Midcontinent Independent System Operator, Inc. (MISO), is taking action to increase transmission capacity, including through its Long-Range Transmission Plan (LRTP) initiative. Tranche 1 of LRTP includes projects that will expand transmission capacity. Those large-scale projects, however, are not expected to be in service until 2028 to 2030. And the LRTP projects are not the only opportunities for addressing inefficiencies in the transmission system.[30] The Company looked at its system, focused on locations where there is serious constraints, and considered whether there are any projects that could quickly and cost-effectively be brought online to increase transmission capacity.[31] Given that the Original Brookings Line was constructed with double-circuit capable structures to accommodate future generation

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[23] *Id.* at 13.
[24] *Id.*
[25] Case Nos. PU-09-676 & -678, CAPX2020 GROUP 1 PROJECTS ADVANCE DETERMINATION OF PRUDENCE (ADP) REQUEST SETTLEMENT AGREEMENT (Sept. 22, 2010); Wendland Aff. ¶ 11. .
[26] Case Nos. PU-09-676 & -678, ORDER ADOPTING SETTLEMENT at 3 (Oct. 6, 2010); Wendland Aff. ¶ 11.
[27] Case Nos. PU-09-676 & -678, ORDER ADOPTING SETTLEMENT at 3 (Nov. 10, 2011); Wendland Aff. ¶ 12.
[28] Case Nos. PU-09-676 & -678, ANNUAL PROJECT UPDATE at Attachment A (Feb. 6, 2016); Wendland Aff. ¶ 13.
[29] *See* Affidavit of Mr. Jason Standing, Ex. 2 (JS-1) (Standing Aff.) ¶¶ 12-17, 26-27.
[30] *See* Standing Aff. ¶ 34-42.
[31] Standing Aff. ¶ 35.

growth, the Project quickly emerged as a potential low-cost, low-impact project for increasing transmission capacity.[32]

The Company used the PROduction MODeling (PROMOD) computer modeling program to evaluate the economic impact of the Project.[33] PROMOD is the industry standard market simulation software for economic transmission planning.[34] PROMOD provides a geographically and electrically detailed representation of the topology of the electric power system, including generation resources, transmission resources, and load.[35] This detailed representation allows the model to capture the effect of transmission constraints on the ability to flow power from generators to load.[36] The model can thus calculate future estimated costs of producing electricity, transmission costs, and energy losses based on these assumptions.[37]

The Company typically analyzes the economic impacts of a transmission project by considering the project's impact on adjusted production cost (APC), which is the total production costs of a generation fleet including fuel, variable operations and maintenance, startup cost, and emissions, adjusted for energy market sales and purchases.[38] If a project is forecasted to produce APC savings, those are the estimated benefits of the project. The Company then compares those estimated APC savings to project costs and other impacts.[39]

Xcel Energy's analysis utilized PROMOD to confirm the Company's early assumptions regarding the likely benefits of the Project.[40] This initial "rough check" evaluated whether the Project would produce worthwhile APC savings.[41] Those results indicated net present values of 20 years of APC savings of $113.3 million for MISO as a whole and $44.3 million for NSP.[42] The Company's economic analyses are discussed more in Section IV below.

Based on these favorable APC savings, the Company sought MISO approval for the Project.[43] In August of 2022, NSP submitted a request to MISO for expedited approval of the Project.[44] The Company asked for expedited review so the Project could be

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[32] Standing Aff. ¶ 36.
[33] Standing Aff. ¶ 37.
[34] Standing Aff. ¶ 28.
[35] Standing Aff. ¶ 29.
[36] Standing Aff. ¶ 30.
[37] Standing Aff. ¶ 31.
[38] Standing Aff. ¶ 32.
[39] Standing Aff. ¶ 33.
[40] Standing Aff. ¶ 37.
[41] Standing Aff. ¶ 38. Although the initial modeling data and assumptions were lost due to unrelated computer hardware issues, the overall results were saved. Standing Aff. ¶ 39.
[42] Standing Aff. ¶ 38.
[43] Standing Aff. ¶ 40.
[44] Standing Aff. ¶ 40.

considered for approval as part of the 2022 MISO Transmission Expansion Plan (MTEP22).[45] With MISO approval in late 2022, the Western Segment can realistically be brought online in 2024 and the Eastern Segment in 2025, provided other approval, planning, and development milestones are met. The alternative to expedited consideration as part of MTEP22 would have been to submit the project for possible approval in MISO's 2023 MISO Transmission Expansion Plan, which could have delayed the Project—and the savings it is projected to provide—a full calendar year. Xcel Energy was not required to submit the preliminary PROMOD modeling as part of the expedited review and approval process.

The Project was subsequently recommended for approval by the MISO Board of Directors.[46] In December 2022, the MISO Board of Directors approved the MTEP22 report and Appendix A.[47] The Project is listed in the final, approved Appendix A along with the MTEP22 report and thus has the necessary MISO approval.[48]

E. Reliability Analyses

Xcel Energy conducted a study to determine whether the Project would impair the reliability of the transmission system.[49] The results of the Company's study showed no reliability impacts resulting from the Project.[50] Moreover, the analysis indicated that the addition of the second 345kV line along the sections in question improves reliability by reducing or eliminating overloads under certain contingencies.[51] The Project was developed and is proposed based on the economic benefits of expanding transmission capacity. Nevertheless, the improved reliability in some scenarios is a welcome additional, albeit secondary, benefit of the Project.

MISO also conducted its own reliability assessment of the MTEP22 portfolio as a whole. As the Project is a part of the overall portfolio, it was necessarily included in that MISO study. The MTEP22 portfolio, including the Project, satisfied MISO's reliability assessment and the MTEP22 portfolio was accepted by MISO's Board of Directors at its meeting in December 2022.[52]

The Project's impact on reliability has thus been considered both on an individual project basis and along with the other MISO transmission projects approved in late

[45] Standing Aff. ¶ 40.
[46] Standing Aff. ¶ 41.
[47] Standing Aff. ¶ 41.
[48] The Project is listed as Project 23452 in both Appendix A and the main body of the MTEP22 report, which can be accessed at https://cdn.misoenergy.org/MTEP22%20Report627345.pdf; *see also* Standing Aff. ¶ 41.
[49] Standing Aff. ¶ 70.
[50] Standing Aff. ¶ 72.
[51] Standing Aff. ¶ 73.
[52] *See* MTEP22 Report, https://cdn.misoenergy.org/MTEP22%20Report627345.pdf.

2022, and both studies produced satisfactory results. To summarize, the Project will provide some reliability benefits.

F. Project Costs

NSP developed a Project cost estimate based on an estimated route length, rerouting costs, and substation upgrade costs.[53] There are several main categories of these cost estimates: (1) engineering, design, permitting, and land rights; (2) material procurement; and (3) construction labor and equipment. Each of these components also includes a risk reserve.[54] AFUDC is listed separately as a footnote in the table below.

Xcel Energy relied on the Company's proprietary cost database to prepare a cost estimate for the transmission line portions of the Project.[55] The database incorporates historical labor and material costs from similar projects.[56] This database is updated based on current market conditions and contingency factors.[57]

Xcel Energy identified the necessary upgrades for each substation as a first step to estimate substation upgrade costs.[58] Xcel Energy then estimated material, construction, design, and permitting costs based on cost estimates for these items from prior substation improvement projects.[59]

Xcel Energy identified potential risks that could result in additional costs to calculate an appropriate risk contingency.[60] These potentials risks are on top of the contingency factors included in Xcel Energy's proprietary cost database. These risks include unexpected weather conditions, poor soil conditions in areas where no soil data was obtained, transmission line outage constraints, river crossings, labor shortages, and market fluctuations in material pricing and labor costs.[61] Xcel Energy then developed an appropriate cost contingency for each of these risks and applied them to each of the three cost categories listed above.[62]

Xcel Energy estimates construction of the Project will cost $100.2 million.[63] This estimate includes substation construction and all substation equipment.[64] These costs

[53] Wendland Aff. ¶ 47.
[54] Wendland Aff. ¶ 48.
[55] Wendland Aff. ¶ 49.
[56] Wendland Aff. ¶ 49.
[57] Wendland Aff. ¶ 49.
[58] Wendland Aff. ¶ 51.
[59] Wendland Aff. ¶ 51.
[60] Wendland Aff. ¶ 50.
[61] Wendland Aff. ¶ 50.
[62] Wendland Aff. ¶ 50.
[63] Wendland Aff. ¶ 52.
[64] Wendland Aff. ¶ 52.

also include all transmission line costs (including materials, associated construction, permitting and design costs, and risk reserve).[65]

Tables 1 and **2** provide a breakdown of the Project cost estimates for each segment, with AFUDC.[66]

Table 1: Project Capital Expenditure Estimates Western Segment

Project Components	Cost
Second Circuit*	$42.9 million
Brookings County Substation Upgrade	$4.0 million
Lyon County Substation Upgrade	$11.0 million
Project Total	**$57.8 million**
* includes the cost of reconfiguring the in- and out-tap at the Steep Bank Lake Substation	

Table 2: Project Capital Expenditure Estimates Eastern Segment

Project Components	Cost
Second Circuit*	$29.9 million
Helena Substation Upgrade	$3.7 million
Hampton Substation Upgrade	$10.6 million
Project Total	**$44.2 million**
* includes the cost of the Chub Lake Substation transmission line reroute	

The total capital additions, including AFUDC, is estimated at $102.0 million.[67]

G. Project Schedule and Work Force

Table 3 provides the permitting and construction schedule currently anticipated for the Project.[68] This schedule is based on information known as of the date of filing and may be subject to change as further information develops or if there are delays in obtaining the necessary federal, state, or local approvals required prior to construction. Xcel Energy estimates it will engage 60 to 80 laborers for Project construction.[69]

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[65] Wendland Aff. ¶ 52.
[66] Wendland Aff. ¶ 53.
[67] Wendland Aff. ¶ 52.
[68] Wendland Aff. ¶ 45.
[69] Wendland Aff. ¶ 46.

Table 3: Anticipated Project Schedule

Activity	Estimated Dates
North Dakota ADP Proceeding	Through Beginning of Second Quarter of 2024
Required Federal, State, and Local Permits Obtained	Through Beginning of Second Quarter of 2024
Start Project Construction – Western Segment	April 1, 2024
Western Segment In Service	September 1, 2024
Start Project Construction Eastern Segment	April 1, 2025
Eastern Segment In Service	September 15, 2025

It is critical that the Company is able to begin construction of the Western Segment and Eastern Segment in the early spring of 2024 and 2025, respectively. Only by starting construction early in the construction season can the Company complete construction before times of traditionally high-winds in the fall. Completing construction before the high-wind season will help limit the costs associated with the loss of transmission capacity when the first circuit is taken out of service to accommodate installation of the second circuit. Similarly, having the second circuit in service before the fall will ensure additional transmission capacity is online when needed most.

IV. ECONOMIC ANALYSIS

NSP is proposing the Brookings Second-Circuit Project to expand transmission capacity. Expanding transmission capacity will increase the efficiency of the transmission system, by allowing MISO to dispatch a more economic mix of generating resources. Currently, there is limited transmission capacity in the MISO electric transmission system.[70] This limited transmission capacity leads to inefficiencies whereby the lowest marginal cost generation mix is not always called on to serve areas with significant load.[71] These inefficiencies can lead to customers paying more for electricity because generators with a higher marginal cost from areas without transmission constraints are used to meet customer demand.[72] By adding more transmission capacity, the Project will allow for more transmission of energy with a lower marginal cost.[73]

This section first briefly describes how expanding transmission capacity can save customers money. The balance of the section provides the estimated APC savings from the Project.

[70] Standing Aff. ¶ 12.
[71] Standing Aff. ¶¶ 14-15.
[72] Standing Aff. ¶ 17.
[73] *See* Standing Aff. ¶ 16.

a. Consequences of Inadequate Transmission Capacity

Insufficient transmission capacity has become an increasingly serious problem in the MISO territory in recent years.[74] MISO operates day-ahead and real-time energy markets as part of carrying out its responsibility to operate an energy market in an efficient manner.[75] Limited transmission capacity can impair the efficient operation of these markets.[76] Limits on the capacity of transmission facilities can prevent MISO from dispatching the generation mix with the lowest marginal cost during all hours of the year, increasing wholesale energy costs.[77]

There is currently energy with low marginal costs available in the region that is sometimes unable to serve load centers, due to transmission constraints in Minnesota, North Dakota, and South Dakota.[78] Some energy cannot be provided to load centers because the loading limits on certain transmission system components preclude this additional energy from being delivered along those facilities.[79] As a result, energy with a higher marginal cost from other areas without transmission constraints must be dispatched.[80] This curtailment creates inefficiencies in the wholesale energy market and increases costs.[81]

Figure 4 below illustrates how transmission constraints affect the energy used and pricing in a single moment of time. The illustration assumes an energy need of 1,100 megawatts (MW) that could be supplied by two potential generators, one at a marginal cost of $20 per MW and one at a marginal cost of $100/MW.[82]

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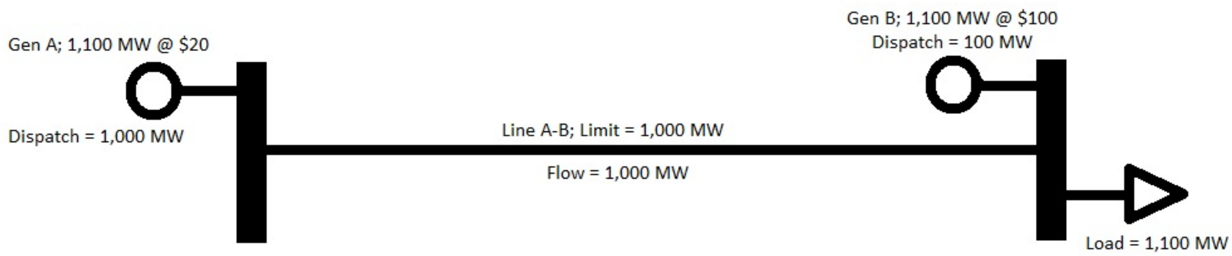
74 Standing Aff. ¶ 12.
75 Standing Aff. ¶ 13.
76 Standing Aff. ¶ 14.
77 Standing Aff. ¶¶ 15, 17.
78 Standing Aff. ¶¶ 15, 17.
79 Standing Aff. ¶ 17.
80 Standing Aff. ¶ 17.
81 Standing Aff. ¶¶ 14, 17.
82 Standing Aff. ¶ 19.

Figure 4
Transmission Constraint Illustration



In this theoretical intact system, Generator A has the generation capacity to serve the entire 1,100 MW needed at a marginal cost of $20/MW but cannot do so because of the 1,000 MW transmission capacity limit on Line A-B.[83] Instead, Generator A's dispatch is limited to 1,000 MW and Generator B will be called on to deliver the remaining 100 MW at a marginal cost of $100/MW.[84] If Generator A were able to deliver the entire 1,100 MW it can generate, the energy cost would be $22,000 assuming no energy is lost during transmission.[85] Due to system constraints, the total cost to deliver the 1,100 MW rises to $30,000 because 100 MW cannot be delivered, and more expensive replacement energy is required from Generator B (1,000 MW X $20 for Generator A plus 100 MW X $100 for Generator B).[86] The upshot is the transmission limits lead to inefficiencies whereby the overall cost of energy increases to $8,000 or 36% in this simplified example.[87] When there is sufficient transmission capacity, the lowest-cost generator, regardless of fuel source, is the one that serves load.

Transmission constraints have become an increasingly significant factor in MISO, including in MISO Zone 1, which includes the Project area.[88] The analysis of the Project's benefits in the following section demonstrates the increases in transmission capacity provided by the Project is forecasted to produce significant savings as a result of more efficient market operation.

b. APC Savings

NSP used PROMOD to analyze the APC savings from the Project. The PROMOD modeling relied on the MTEP21 Future 1 assumptions.[89] After receiving MISO approval for the Project, the Company evaluated the assumptions used in PROMOD

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[83] Standing Aff. ¶ 20.
[84] Standing Aff. ¶¶ 21-22.
[85] Standing Aff. ¶ 23.
[86] Standing Aff. ¶ 24.
[87] Standing Aff. ¶ 25.
[88] Standing Aff. ¶ 12.
[89] Standing Aff. ¶ 47.

to ensure they realistically project the future in the Company's portion of MISO.[90] The Company concluded the MTEP21 Future 1 assumptions do not align with the Company's current resource plans.[91] Accordingly, the Company decided to run PROMOD based on assumptions that better align with the Company's plans.[92] The Company also adjusted that forecast to account for the results of recent procurements.[93] Schedule 3 of the Affidavit of Mr. Jason Standing, Ex. 2 (JS-1) provides the assumptions the Company used in the latest PROMOD analysis of the Project.

Additionally, although PROMOD is typically used in MISO planning to provide APC savings over a 20-year period,[94] the book life of the Project is approximately 63 years and should provide benefits to customers over that full life.[95] To more accurately reflect the benefits from that full expected book life, the Company extrapolated from PROMOD using the trend-line from the 20-year APC data to estimate the present value of 63 years of APC savings.[96] The results of that 63-year analysis are set forth in **Table 4**. **Table 4** also presents the results of a 20-year analysis and a 40-year analysis, along with the corresponding benefit-cost ratios, which assumes NSP is assigned the full Project cost. The Project is projected to provide significant benefits when analyzed over any of those timeframes. The Company used a 6.36% discount rate based on the Company's weighted average cost of capital.[97]

As reflected in **Table 4**, the Company estimates APC savings over 63-years of $334.83. Since APC savings do not account for the capital cost of the Project, the Company compared those APC savings to the Project's capital costs.[98] This comparison resulted in a benefit-cost ratio of 2.53 if the Company owns the entire Project. The Company estimates MISO-wide APC savings over 63 years of $833.86 million and a MISO-wide benefit-cost ratio of 6.31.

Schedule 4 of the Affidavit of Mr. Jason Standing, Ex. 2 (JS-1) provides the cost benefit ratio assuming the other CapX2020 Brookings Owners invest in the Project. Under a shared ownership scenario, the costs of the Project are spread between the owners and the Company is assigned only $78.6 million of the Project costs.[99] Therefore, the

[90] Standing Aff. ¶ 50.
[91] Standing Aff. ¶¶ 50-51.
[92] Standing Aff. ¶ 51.
[93] Standing Aff. ¶ 51.
[94] Standing Aff. ¶¶ 53-54.
[95] Standing Aff. ¶ 55.
[96] Standing Aff. ¶ 56.
[97] Standing Aff. ¶ 60.
[98] Standing Aff. ¶ 33.
[99] Standing Aff. ¶ 65.

benefit-cost ratio to the Company increases to 3.29 if the other CapX2020 Brookings Owners participate in the Project.[100]

Table 4: Forecasted APC Savings and Benefit Cost Ratios

Timeline	APC Benefits/Benefit-Cost Ratio	NSP	MISO
20 Year Present Value	APC Benefits ($MM)	$149.00	$322.65
	Benefit-Cost Ratio	1.36	2.94
40 Year Present Value	APC Benefits ($MM)	$272.07	$655.84
	Benefit-Cost Ratio	2.11	5.08
63 Year Present Value	APC Benefits ($MM)	$334.83	$833.86
	Benefit-Cost Ratio	2.53	6.31

Another benefit of the Project is that the capacity the Project provides will help reduce the cost of outages that will be required during the future construction of LRTP Tranche 1 portfolio projects, specifically, future outages that will be necessary on the existing transmission lines between Alexandria and Monticello, and Crandall and Wilmarth.[101] The Company does not yet have detailed schedules that would allow for precise predictions regarding the length and timing of the LRTP construction-related outages. In absence of detailed schedules, the Company used rough assumptions to obtain a sense of the magnitude of benefits the Project could provide in mitigating LRTP-outage impacts.[102] Assuming outages lasting for calendar year 2030, the modeling predicts that, on a MISO-wide basis, the Project will reduce the APC impacts of an outage on the Alexandria to Monticello line by approximately $11-12 million and on the Crandall to Wilmarth line by approximately $15 million.[103]

To be clear: the Project is not being proposed to mitigate the impact of outages caused by LRTP Tranche 1 construction. The Project is aimed at reducing production costs over an extended period, not providing short-term relief from the impacts of construction-related outages. The anticipated mitigation of outage-related losses are an ancillary—but real—benefit. The estimates of the potential amount of such benefits are provided only to give an approximate sense of the magnitude of outage-related benefits.

[100] Standing Aff. ¶ 65.
[101] Standing Aff. ¶ 67.
[102] Standing Aff. ¶ 68.
[103] Standing Aff. ¶ 69.

c. Rate Impact

The Company also conducted a high-level rate impact for the Project.[104] To complete this analysis, the Company first determined the annual revenue requirement impact for the capital costs of the Project. Schedule 5 of the Affidavit of Mr. Jason Standing, Ex. 2 (JS-1), provides the results of this calculation for a 20-year period. The Company is providing 20 years of revenue requirement consistent with its general practice as any additional years would be too speculative.[105] As a capital-only analysis, the revenue requirement projections in Ex. 2 (JS-1), Schedule 5, do not account for future operation and maintenance expenses for the Project or fuel impacts.[106]

As noted in Section III.C, the other CapX2020 Brookings Owners have the option to participate in ownership of the respective segments of the Project. The analysis in Ex. 2 (JS-1), Schedule 5, provides the forecasted annual revenue requirements for the Company under both a scenario in which the other CapX2020 Brookings Owners choose not to participate, meaning the Company retains full ownership of the Project, and one in which all other CapX2020 Brookings Owners elect to participate. The Company assumes if a CapX2020 Brookings Owners elects to participate in one segment of the Project, it will elect to participate in both segments.

The revenue requirement calculations in Ex. 2 (JS-1), Schedule 5, include the NSP system as a whole (both NSP Minnesota and NSP Wisconsin (NSP Companies)) and are then adjusted to a North Dakota jurisdictional basis for NSP Minnesota. For Year 1, the estimated North Dakota nominal revenue requirement would be approximately $500,000 under a full Company ownership scenario and $385,000 assuming all other CapX2020 Brookings Owners elect to participate.[107] In subsequent years over the 20-year period, the estimated North Dakota nominal revenue requirement would decrease so that by Year 20 it would be $296,000 under full NSP ownership and $228,000 under a shared ownership scenario.[108]

The Company provided only a capital rate analysis since it is the only analysis that can be conducted with sufficient accuracy over an extended period. Although the Company has conducted intensive production cost modeling, because that modeling only models production cost impacts, it is nearly impossible to reduce that down to impacts to fuel costs, dispatch costs, or other information necessary to calculate net savings on a retail revenue basis. That said, the Company's benefits analysis remains sound and demonstrates that benefits outweigh costs for this Project.

[104] Standing Aff. ¶ 74.
[105] Standing Aff. ¶ 76.
[106] Standing Aff. ¶ 77.
[107] Standing Aff. ¶¶ 78-79, Ex. 2, Schedule 5.
[108] Standing Aff. ¶¶ 78-79, Ex. 2, Schedule 5.

As discussed, to analyze Project benefits, the Company used the PROMOD modeling tool to forecast future economic benefits of the Project in the form of APC.[109] Although translating those estimated benefits into net retail savings is not practically feasible, it is reasonable to compare the APC savings with the capital revenue requirements analysis to provide a general understanding of the overall positive economic impact of the Project on customer rates.

If Project ownership is shared among the CapX2020 Brookings Owners, in Year 1 (2026) the total estimated NSP Companies nominal revenue requirement will be $7.6 million,[110] which is less than the estimated annual APC savings to NSP of $8.3 million in Year 1.[111] That is, APC benefits are forecasted to exceed the Project revenue requirement in Year 1—and that is forecasted to be the case for every year thereafter. If only NSP owns the Project, annual savings begin to exceed the NSP annual revenue requirements by Year 6 (2031) and then continue for every year after.[112]

V. ALTERNATIVES

There is currently congestion on the Original Brookings Line. To address this, the Project proposes double-circuiting the Western and Eastern Segments of the Original Brookings Line. In this section, the Company discusses potential alternatives to this Project, including constructing an entirely new transmission line, installing the second circuit on only the Western Segment or Eastern Segment, and taking no action. This section concludes none of these alternatives are feasible and cost-effective alternatives to the Project.

One obvious alternative to the Project that would also reduce congestion would be to construct an entirely new transmission line along a different route but serving similar areas. This alternative would cost significantly more than the Project; take longer to construct (thus postponing the congestion-reduction benefits); require the Company to seek approval from MISO for a new project (contributing to the delay associated with this alternative); and have greater impacts on communities, property owners, and the environment. Simply put, the Project is superior to constructing a new transmission line because it largely takes advantage of the structures and route of the Original Brookings Line, thus limiting costs, and environmental and societal impacts. Given the obvious advantages of double-circuiting along the route of the Original Brookings Line, including the significantly reduced costs, the Company did not design specific alternative lines (and routes) or create estimates of the costs for constructing such potential alternative transmission lines.

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[109] Standing Aff. ¶ 28.
[110] Standing Aff. ¶ 80, Ex 2, Schedule 5.
[111] Standing Aff. ¶ 81, Ex. 2, Schedule 4.
[112] Standing Aff. ¶ 82, Ex. 2, Schedules 4-5.

Another possible alternative involves installing a second circuit along only one of the segments—either the Western or Eastern Segment. The Company concluded that installing a second circuit along only one of the segments is not a viable alternative after analysis showed that constructing only one of two segments would create reliability issues.

Simply not constructing or developing the Project would avoid project development and construction costs. But the analysis set forth above indicates that the Project is expected to produce $334.83 million in NSP benefits, which outweigh construction costs. Also, the nature of the Project—double-circuiting of existing transmission poles—limits the environmental and societal impacts. For these reasons, the Company concluded the Project is more prudent than the no action alternative.

VI. REQUIRED APPROVALS

In addition to an ADP, the Company will also need to obtain other local, state, and federal approvals related to the environment, cultural resources, and project need. Those permits include a Certificate of Need and approval of a Minor Alteration to the Original Brookings Line's route permit. **Table 5** lists additional permits and approvals that may be required for the Project. Typical municipal permit categories are listed, but specific permits may vary from city to city and are limited. Once the Commission issues a Minor Alteration to the existing route permit, local zoning, building, and land use rules in Minnesota are preempted.[113]

[113] Minn. Stats. § 216E.10, subd. 1.

Table 5:
Potential Permits/Compliance Requirements

Permit	Jurisdiction
Local Approvals	
Road Crossing/Right-of-Way Permits	County, Township, City
Lands Permits	County, Township, City
Utility Permits	County, Township, City
Oversize / Overweight Permits	County, Township, City
Driveway/Access Permits	County, Township, City
Local/State/Federal Application for Water/Wetland Projects (under Minnesota's Wetlands Conservation Act)	Minnesota Board of Water and Soil Resources (BWSR)
State Approvals	
Advance Determination of Prudence	NDPSC
Certificate of Need and Minor Alteration	MPUC
Certification to Construct, Expand, or Improve a Transmission Facility	South Dakota Public Utilities Commission
Threatened & Endangered Species Consultation	Minnesota Department of Natural Resources (MDNR)
License to Cross Public Waters	MDNR – Lands and Minerals
Construction Dewatering Permit	MDNR
Utility Permit	Minnesota Department of Transportation (MnDOT)
Driveway/Access Permits	MnDOT
Oversize/Overweight Permits	MnDOT
Wetland Conservation Act Exemption Concurrence	BWSR
Section 401 Water Quality Certification	Minnesota Pollution Control Agency (MPCA)
National Pollutant Discharge Elimination System Permit	MPCA
Cultural Resources Review	Minnesota State Historic Preservation Office
Federal Approvals	
Section 7 Consultation	U.S. Fish and Wildlife Services
Section 10 Permit	U.S. Army Corps of Engineers (USACE)
Section 404 Permit	USACE
Notice of Proposed Construction (7460-1)	Federal Aviation Administration (FAA)
Notice of Actual Construction or Alteration	FAA
Farmland Protection Policy Act/Farmland Conversion Impact Rating	U.S. Department of Agriculture, Natural Resources Conservation Service

VII. PRUDENCE OF THE PROJECT

The proposed Project will allow the Company to take advantage of double-circuit capable structures along the Original Brookings Line. NSP will install a second-circuit on the unused davit arms of existing transmission poles. Because the Project will require the installation of a relatively limited number of new poles, the cost of the Project will be considerably lower than constructing an entirely new transmission line to increase transmission capacity. Likewise, avoiding the need to add a significant number of new poles will limit the impacts to society and natural resources.

These limited new costs and impacts are juxtaposed against significant APC savings. The Company projects NSP savings of $334.83 million over the life of the Project and MISO-wide savings of $833.86. If the NSP-only benefits of the Project are used in a cost-benefit analysis, the result is a cost-benefit ratio of 2.53 assuming NSP is assigned the full Project cost, and 3.29 assuming shared ownership and NSP is assigned $78.6 million of the Project cost. Using MISO-level benefits, the result is a cost benefit ratio of 6.31. No matter how the Project costs and savings are calculated, the savings far outstrip the costs, demonstrating the prudence of the Project.

VIII. CONCLUSION

For all the reasons set forth above, Xcel Energy respectfully requests the Commission grant an ADP for the Company's proposed Brookings County – Lyon County and Helena – Hampton Second-Circuit Project.

Dated: August 29, 2023

Northern States Power Company

Respectfully submitted,

/s/Christopher J. Shaw

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