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BEFORE THE PUBLIC SERVICE COMMISSION OF THE STATE OF NORTH DAKOTA

NORTHERN STATES POWER COMPANY
ADVANCE PRUDENCE – 1,550 MW WIND PORTFOLIO
APPLICATION

CASE NO. PU-17-____

APPLICATION FOR ADVANCE DETERMINATION OF PRUDENCE

INTRODUCTION

Northern States Power Company, doing business as Xcel Energy (NSP or Xcel Energy or the Company), submits to the North Dakota Public Service Commission (Commission) this Application for an Advance Determination of Prudence (Application) for a 1,550 MW portfolio of wind generation to be added to the integrated NSP System (Wind Portfolio). This application is being made pursuant to N.D.C.C. § 49-05-16, the Settlement Agreement in Case No. PU-07-776, and the Company's commitments in Case No. PU-12-59.

The Wind Portfolio consists of the following cost-effective, geographically- and structurally-diverse wind projects:

Project Name	Size	Type	Location	In-Service Date	Levelized Cost ($/MWh)
					[TRADE SECRET BEGINS
Foxtail	150 MW	Self-Build	Dickey County, ND	3Q 2019	
Crowned Ridge	600 MW	Combined BOT and PPA	Codington County, SD	4Q 2019	
Lake Benton	100 MW	BOT	Pipestone County, MN	4Q 2019	
Clean Energy #1	100 MW	PPA	Mercer and Morton Counties, ND	4Q 2019	
Blazing Star I	200 MW	Self-Build	Lincoln County, MN	4Q 2019	
Blazing Star II	200 MW	Self-Build	Lincoln County, MN	3Q 2020	
Freeborn	200 MW	Self-Build	Freeborn County, MN, and Worth and Mitchell Counties, IA	4Q 2020	

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The Wind Portfolio represents a prudent opportunity for Xcel Energy to drive down overall system costs by capturing the lowest cost wind projects that we have seen to date due, in part, to the ability to fully capture the Federal Production Tax Credit (PTC). Over the life of the Wind Portfolio, we are anticipating savings on a present value of revenue requirements (PVRR) basis (exclusive of externality costs) of approximately $1.6 billion for the entire NSP System or approximately $85 million for our North Dakota customers.

The Wind Portfolio is the result of the Company's proposal to add material amounts of wind by 2020 in its most recently completed Upper Midwest Integrated Resource Plan (IRP).[1] In light of the Company's proposal, the Minnesota Public Utilities Commission (MPUC) ordered that the Company acquire at least 1,000 MW of wind.[2] Consequently, the Company developed four self-build options and issued a Request for Proposal (RFP) to probe the market for other projects; the RFP also helped to ensure our self-build options were competitive with the current market. The results of this work indicated that the market was robust and pricing was excellent—the Company received over 30 RFP responses, at prices below $22/MWh on a levelized basis,[3] from 13 developers totaling approximately 5,600 MW of nameplate capacity. While the MPUC's IRP Order set a floor of 1,000 MW of wind to be acquired, the pricing available to us at this time was so attractive, and our analysis showed that the addition of more low-cost wind projects will drive down overall system costs, that we sought to acquire as much low-cost wind as feasible. Accordingly, our analysis of the RFP responses and the self-build options led us to conclude that the 1,550 MW Wind Portfolio strikes the best balance between maximizing fuel cost savings to our customers and prudent project development consistent with transmission support.

We believe our Wind Portfolio will provide substantial benefits to our customers and the communities we serve. These benefits include:

- *Customer Savings*: The Wind Portfolio offers system cost savings over its life to our customers and fits our strategy of having a geographically diverse balance of Company-owned and purchased power agreement (PPA) wind resources. Production at these facilities will displace generation on our system or purchases in the Midcontinent Independent System Operator, Inc. (MISO) wholesale market with higher marginal costs. Our analysis indicates approximately $1.6 billion in PVRR savings over the life of the Wind Portfolio,

[1] *See In the Matter of Xcel Energy's 2016-2030 Integrated Res. Plan*, Docket No. E002/RP-15-21, 2016-2030 UPPER MIDWEST RESOURCE PLAN (Jan. 2, 2015). Our IRP was filed with the Commission in Case No. PU-15-019.

[2] *In the Matter of Xcel Energy's 2016-2030 Integrated Res. Plan*, Docket No. E002/RP-15-21, ORDER APPROVING PLAN WITH MODIFICATIONS AND ESTABLISHING REQUIREMENTS FOR FUTURE RESOURCE PLAN FILINGS at 3 (Jan. 11, 2017) [hereinafter IRP Order].

[3] For comparison purposes, Xcel Energy's Courtenay wind project has a levelized cost of **[TRADE SECRET BEGINS TRADE SECRET ENDS]**.

as compared to adding no wind in the same period.

- *Economic Development*: The Wind Portfolio will generate significant and lasting economic benefits for our communities and all of the NSPM states. These include the provision of low-cost energy to meet our customers' needs, income to landowners in exchange for wind easements on their property, the creation of hundreds of construction jobs and dozens of ongoing maintenance jobs, and the contribution of tax revenues and other fees for our communities and states. This includes tax revenues, fees, and jobs arising from the Foxtail project in Dickey County, North Dakota, and the Clean Energy #1 project in Mercer and Morton Counties, North Dakota.
- *Environmental Performance*: The addition of the Wind Portfolio will help enable the Company to continue along a path of improved environmental performance that we began over a decade ago. In particular, the Wind Portfolio will contribute to the Company's carbon reduction goals with an estimated carbon dioxide emissions reduction of approximately 2 million tons annually, on average.
- *Compliance*: The addition of the Wind Portfolio will help enable the Company's compliance with state and federal energy policies in a cost effective manner.

We recognize that our Wind Portfolio is not wholly consistent with the Commission's strict "need + least cost" planning paradigm. As confirmed in our most recent IRP and discussed at length in our Application for a Resource Treatment Framework (RTF) in Case No. PU-12-813, *et. al.*, Xcel Energy does not anticipate a load serving need to arise until the mid-2020s, after the Wind Portfolio will be fully in-service.[4] Our Wind Portfolio can be considered least cost, however, in that it will drive down overall system costs over its life and add capacity to the NSP System in anticipation of the mid-2020s need. The Commission has approved wind projects with this type of profile in the past, including the Company's Courtenay, Odell, Pleasant Valley, and Border Winds projects in Case Nos. PU-13-706, PU-13-707, PU-13-708, and PU-13-742, respectively.[5] We ask the Commission to grant an advance determination of

[4] *N. States Power Co. 2013 Elec. Rate Increase Application et al*, Case Nos. PU-12-813, *et al.*, APPLICATION FOR CONSIDERATION OF A RESOURCE TREATMENT FRAMEWORK TO ADDRESS JURISDICTIONAL COST ALLOCATION ISSUES (Jan. 3, 2017); *In the Matter of N. States Power Co., a Minn. Corp. d/b/a Xcel Energy, Jurisdictional Cost Allocation Matters*, Docket No. E002/M-16-223, APPLICATION FOR CONSIDERATION OF A RESOURCE TREATMENT FRAMEWORK TO ADDRESS JURISDICTIONAL COST ALLOCATION ISSUES (Jan. 3, 2017).

[5] The Courtenay and Border Winds projects enjoyed a rebuttable presumption of prudence under North Dakota state law and were approved on that basis. *N. States Power Co. 2013 Elec. Rate Increase Application et al*, Case Nos. PU-12-813 et al, ORDER ADOPTING SETTLEMENT at 6, 8-9 and attached Settlement Agreement at 22 (Feb. 26, 2014). The Pleasant Valley and Odell projects were not approved when initially brought before the Commission nor were they fully disposed of in the settlement of those cases. *Id.* at 9. Rather, those two

prudence (ADP) for our Wind Portfolio here on a similar basis.

Our Wind Portfolio is also implicated in our currently pending RTF proceeding before the Commission in Case No. PU-12-813, et al. and the MPUC in Docket No. E002/M-16-223. As part of our proposed RTF, we have suggested that it may be appropriate, as part of a larger overall solution, to not allocate the capacity, energy, revenues, and costs of the Wind Portfolio to our North Dakota customers. As discussed in the RTF Application, we look forward to engaging in discussions with the Commission and its Staff along with stakeholders in Minnesota and other Xcel Energy states regarding our RTF and how our Wind Portfolio should be addressed as part of a broader solution. Consequently, the final disposition of the Wind Portfolio could change as a result of the RTF proceeding.

Consistent with the Commission's requirements in Case No. PU-12-59, the Company has included conditions precedent in its contracts for the Wind Portfolio requiring that an ADP be issued by the Commission no later than August 2017 or Xcel Energy has the right to terminate the contract. In addition, in order to accommodate the implementation timelines for the Wind Portfolio necessary to achieve full PTC benefits, it is necessary to move as quickly as practicable. For these reasons, Xcel Energy respectfully requests that the Commission grant an ADP for the Wind Portfolio no later than July 2017 regardless of the final disposition of the Wind Portfolio that may result from the RTF proceeding.

In support of our Application, Xcel Energy provides the following Direct Testimony:

- Policy Testimony – Aakash H. Chandarana
- Resource Planning Testimony – Philip Joseph "P.J." Martin

The remainder of this Application provides the following:

- Description of the Applicant;
- Compliance Matters;
- Development of the Wind Portfolio;
- Description of the Wind Portfolio;
- Economic Analysis of the Wind Portfolio;

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projects were ultimately approved through settlement between the Company and Advocacy Staff due to the cost savings that could be realized by the Odell and Pleasant Valley projects' pricing and profile. *N. States Power Co. 2013 Elec. Rate Increase Application et al*, Case Nos. PU-12-813, *et al.*, ORDER ADOPTING SETTLEMENT at 5 (Mar. 9, 2016).

- Reasonable Mitigation of Risks;
- Prudence of the Wind Portfolio; and
- Conclusion.

In sum, with wind generation at a historically low price, the Wind Portfolio presents a significant opportunity to drive down overall system costs and reduce carbon and other emissions. We respectfully request the Commission approve the 1,550 MW Wind Portfolio as additions to the NSP System, in whole or in part, as deemed appropriate by the Commission.

I. COMPLIANCE MATTERS

A. DESCRIPTION OF APPLICANT

Xcel Energy is a Minnesota corporation duly authorized to conduct business in the State of North Dakota as a foreign corporation. The Company 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. The name and address of Xcel Energy is:

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

Xcel Energy 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, and are incorporated herein by reference.

Xcel Energy has service territory in five upper Midwest states including North Dakota. We presently serve approximately 94,000 retail electric customers in and around Fargo, Grand Forks, and Minot, North Dakota. We own just over 250 miles of transmission lines and 14 substations in North Dakota.

B. COMMUNICATION AND SERVICE

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

David H. Sederquist
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C. STANDARD OF REVIEW

North Dakota Century Code section 49-05-16(1)(d) authorizes the Commission to issue an ADP if it "determines that the resource addition is prudent." Section 49-05-16(7) further provides that "[t]here is a rebuttable presumption that a resource addition located in the state is prudent."

This standard is similar to the "honestly and prudently invested" standard that the Commission uses for ratemaking.[6] The general prudence standard calls for determining whether the utility action was reasonable at the time it was taken under all relevant circumstances.[7] 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

[6] *See* N.D.C.C. § 49-06-02.

[7] *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).

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

D. Compliance with Filing Obligations

North Dakota Century Code section 49-05-16 allows for a public utility to seek an ADP from the Commission at the utility's discretion. Xcel Energy, in the Settlement Agreement in Case No. PU-07-776, agreed to file an application for an ADP for, among other things, generation resources over 50 MW in nameplate capacity.[8] The Commission has clarified this requirement, finding that an application for an ADP is not advanced in the event that Xcel Energy is already contractually obligated to move forward with a particular resource addition prior to filing its application with the Commission.[9] Last, Xcel Energy has committed to filing its ADP applications within fourteen days of seeking similar approvals in Minnesota.[10]

With this Application, the Company has met its filing obligations. This Application complies with the requirements of N.D.C.C. § 49-05-16 and the Settlement Agreement in Case No. PU-07-776. Additionally, key contracts for the purchase of sites for the self-build projects, PPAs, and purchase and sale agreements (PSA) for Build-Own-Transfer (BOT) projects are conditioned on the Commission granting an ADP for the Wind Portfolio, consistent with the Commission's precedent set in Case No. PU-12-59.

The comprehensive wind proposal filed with the MPUC on March 15, 2017 triggers our fourteen-day filing obligation, because it comprehensively describes the proposed acquisition (i.e., the Wind Portfolio), financial modeling, rate impact information, and other information traditionally provided when seeking project approval. Moreover, it was through that filing that we formally sought MPUC approval for the Wind Portfolio. We are making this Application on March 29, 2017, fourteen days after making a filing seeking approval for our Wind Portfolio in Minnesota.

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

[9] *N. States Power Co. Advance Determination of Prudence – Geronimo Wind Application*, Case No. PU-12-59, FINDINGS OF FACT, CONCLUSIONS OF LAW AND ORDER at 3 (Dec. 21, 2012).

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

II. DEVELOPMENT OF THE WIND PORTFOLIO

The Company analyzed market conditions, developed four potential Company-sponsored projects, and undertook an RFP process that yielded a substantial number of proposals at extremely attractive pricing. Together, these efforts result in our recommendation to add 1,550 MW of wind resources—the Wind Portfolio—to the NSP System. Although the Wind Portfolio delivers many benefits, including environmental performance and compliance, the primary driver is the significant and near-term economic benefits it will confer on our customers.

Indeed, the levelized costs of each of these projects is lower than any of our past renewable additions. By way of comparison, the Company's most recent wind projects have a Levelized Cost of Energy (LCOE) in the range of **[TRADE SECRET BEGINS TRADE SECRET ENDS]**, whereas the proposed wind resource additions have LCOEs in the range of **[TRADE SECRET BEGINS TRADE SECRET ENDS]**. This reflects costs that are roughly 20 to 40 percent lower than before.

We have evaluated these seven projects as one portfolio, from both a long-term modeling perspective and near-term rate impact perspective. Our analysis shows that adding the Wind Portfolio to the NSP System, even under the most conservative assumptions, would result in a net benefit of $1.6 billion (on a PVRR basis). While 1,550 MW is the largest renewable energy addition we have made to date, we estimate that the customer rate impacts will be reasonable—and in fact, largely beneficial after the initial years of each project—due to the system savings we can achieve.

The development of our Wind Portfolio has been many months in the making and progressed through several stages. We began by proposing material wind additions in our 2016-2030 IRP filed in North Dakota (Case No. PU-15-19) and Minnesota (Docket No. E002/RP-15-21). As the IRP proceeding progressed in Minnesota, it became evident that we would likely seek approval of a material amount of wind additions. Therefore, we developed the four self-build projects totaling 750 MW, and issued an RFP to probe the market and confirm the cost competitiveness of those self-build projects. Shortly thereafter, the MPUC issued its IRP order approving at least 1,000 MW of wind additions. Based on this IRP order, the attractive pricing we were able to solicit, and the imminent phase-out of the Federal PTC, we developed this proposed Wind Portfolio.

A. INTEGRATED RESOURCE PLAN

We demonstrate the prudence and appropriateness of our Wind Portfolio in this Application and supporting testimony. However, substantial analysis regarding the cost-effective nature of material wind additions between now and 2020 was previously analyzed and tested in our IRP proceeding in Minnesota. Consistent with that analysis, the MPUC approved our acquisition of at least 1,000 MW of wind and approved a process by which we were to acquire our new wind resources. Our Wind Portfolio would be prudent notwithstanding MPUC approval. However, the outcome of the IRP proceeding provided a minimum threshold for the size of our Wind Portfolio and guided the process by which we developed it.

1. At Least 1,000 MW of Wind

Our initial IRP included the addition of 1,400 MW of large-scale solar, 1,800 MW of wind, and 2,856 MW of natural gas-fired resources between 2016 and 2030. Within the first five years of the planning period (2016-2021), we had proposed to add 400 MW of large-scale solar and 800 MW of large-scale wind.

As our IRP proceeding progressed in Minnesota, it became clear that acquiring wind resources would be the most cost-effective resource. Our modeling efforts during the IRP demonstrated that the attractive wind pricing assumptions used in that proceeding (which were higher than the LCOEs of the currently proposed Wind Portfolio) showed material wind additions to be prudent regardless of load-serving needs. To that end, the Company's proposal was modified to acquire at least 1,000 MW of wind resources (with solar development continuing through the Company's Minnesota-based Community Solar Gardens program). In support of this analysis, the MPUC found:

> Despite slight variations in exact timing and magnitude, the record clearly showed that acquisition of wind and possible solar resources in the next five years represents the least-cost method of meeting Xcel's near-term resource needs. The Commission finds that the record shows that it is reasonable to acquire at least 1000 MW of wind by 2019. This acquisition is least-cost even though Xcel does not show a planning capacity deficit until the mid 2020s because it will provide incrementally lower-cost energy, thereby reducing system costs. Upon submission of evidence such as price, bidder

> qualification, rate impact, transmission availability and location, additional acquisition may be approved.[11]

Our work in developing the Wind Portfolio and the analysis presented in this Application confirms this view.

2. *Acquisition Process*

During the course of the IRP proceeding, the MPUC also approved an acquisition process for wind additions in our five-year action plan. This process involved two parts: (1) an RFP for PPAs and BOT proposals; and (2) self-build wind projects totaling 750 MW of wind generation. This acquisition process provides an alternative path for the Company to develop the projects rather than going through the costly and time consuming Certificate of Need process in Minnesota. This helps to ensure we will be able to complete development of our projects with sufficient time to meet all requirements to capture 100 percent of the Federal PTCs. The acquisition process had the following steps:

(1) The Company issues an RFP for wind resources.

(2) The day before receiving wind bids from the RFP, the Company submits to the MPUC its own self-build proposal including estimates of final costs.

(3) The Company evaluates the bids and selects projects based on the following factors:

- (a) Levelized cost;
- (b) Financial capability;
- (c) Project schedule;
- (d) Project design;
- (e) Project risks;
- (f) MISO queue position status;
- (g) Interconnection and network upgrades;
- (h) Energy production profile;
- (i) Site control;
- (j) Project output delivery plan;
- (k) Expected turbine availability;
- (l) Pricing options;
- (m) Project development milestones;
- (n) Exceptions to standard contract terms and conditions; and

[11] IRP Order at 7.

(o) Other relevant factors.

(4) The Company files with the MPUC the results of the bidding process, project rankings, analysis, and the results of a third-party auditor report of its bidding and review process.

Consistent with this process, and in anticipation of the MPUC's decision in the IRP docket, on September 22, 2016, the Company issued an RFP for wind resources with a bid deadline of October 25, 2016. On October 24, 2016, we submitted to the MPUC, and provided a copy to this Commission, our own self-build proposals with estimates of final costs. On October 25, 2016, we received the results of the RFP and began our RFP analysis to both select projects and measure the prudence of our self-build proposals against what was available in the third-party market. On March 15, 2017, we made a filing with the MPUC with our final recommendation proposing the entire 1,550 MW Wind Portfolio for consideration. Consistent with our obligation to file an ADP application with the Commission within fourteen days of making a similar filing in North Dakota, we filed this Application on March 29, 2017.

B. SELF-BUILD PROJECTS

Our 750 MW of self-build projects were selected through a comprehensive site selection process. As we developed the self-build projects, we sought to mitigate issues that relate to fully capturing the Federal PTCs and helping to ensure that there are reasonable transmission interconnection and delivery options.

1. Site Selection

The goal of our selection process was to acquire sites that could offer cost-competitive wind energy to our customers. We evaluated a number of potential sites before selecting the four self-build projects. Our selection process had three primary phases: (1) cost analysis; (2) wind performance analysis; and (3) due diligence reviews.

Our cost analysis was based on our Master Supply Agreement (MSA) with our turbine supplier and our wind project balance of plant (BOP) construction and operating cost model. Our cost model was initially developed for the Grand Meadow Wind Farm in 2008, and we have since used it with the Nobles, Pleasant Valley, Border Winds, and Courtenay wind projects, as well as, most recently, the Rush Creek wind project in Colorado. Our cost model has evolved over the years to reflect our experience with the construction and operation of these wind farms, as well as cost trends in the wind energy industry.

Our wind performance analysis involved the verification of the potential wind energy production of the proposed sites. To do this, we retained a reputable wind consulting company, AWS True Power (AWS), to perform independent wind analysis based on project layout, wind data, site details, and turbine information. We used this analysis to develop Net Capacity Factors (NCF) for the selected sites.

The due diligence process helped to ensure that proposed project sites can be properly developed and are ready and feasible to support our planned project construction schedule. The due diligence process involved asking developers an extensive list of questions about their proposed wind sites that fall into eight general categories: (1) land control; (2) wind data; (3) siting and permitting; (4) technical attributes; (5) site-specific cost considerations; (6) transmission and interconnection; (7) legal; and (8) environmental. Company personnel with relevant skill sets and expertise in these eight categories reviewed the due diligence risk assessments for each proposed site.

2. *Selection of Self-Build Projects*

Through this site selection and due diligence process, we selected the Blazing Star I, Blazing Star II, Foxtail, and Freeborn wind projects. Upon their selection, we entered into PSAs with the developers of these sites to purchase the assets and transfer permits and real-estate rights. The PSAs contemplate closing dates and milestones that will allow the projects to be completed in time to capture 100 percent of the Federal PTCs.

We are developing our self-build projects as a group, in part, because this allows the Company to capitalize on key efficiencies, including leveraging economies of scale in project planning and execution and reducing the schedule-related risks typically associated with individual projects. Additionally, our multi-year project and construction plan will allow us to optimize the use of both internal and external resources.

Consistent with prudent management, we will continue with iterations of our due diligence review process until the closing date of the PSAs for each of the four selected sites.[12] The continued due diligence process is necessary to ensure the contractual deliverables for the site development are timely received, and to further support our project development, engineering, construction, and commissioning toward the planned in-service dates.

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[12] Each of the PSAs contains a condition precedent to closing for Commission approval of this Application.

3. *PTC Safe Harbor Timing Requirements*

In December 2015, the United States Congress passed, and President Obama signed into law, an extension of the Federal PTC. The PTC extension also provided for the phase-down of the tax credit for wind facilities commencing construction after December 31, 2016. The phase-down will occur annually in the following increments: the PTC amount is reduced by 20 percent for wind facilities commencing construction in 2017; the PTC amount is reduced by 40 percent for wind facilities commencing construction in 2018; the PTC amount is reduced by 60 percent for wind facilities commencing construction in 2019; and the PTC is altogether unavailable after 2019 unless it is reauthorized by Congress.

Therefore, to qualify for 100 percent of the PTC amount, our self-build projects must begin construction in 2016 to qualify for the PTCs. By law, there are two ways to begin construction for purposes of obtaining "safe harbor" to capture 100 percent of the PTCs: (1) commencing "physical work of significant nature" at the project site or at a factory on equipment for the project, or (2) incurring at least five percent of the total project cost.[13] With respect to the five percent method, it is important to note that costs are not incurred merely by spending money; the developer must actually take delivery of the equipment by a certain date. Under either safe-harbor method, the projects must be placed in service within four years from the end of the year that construction commenced.

To meet the safe harbor requirements for these wind projects, **[TRADE SECRET BEGINS**

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In addition, we have developed a project schedule that optimizes pricing and involves the sequenced construction of the four self-build projects in order to ensure that they reach commercial operation in time to qualify for 100 percent of the Federal PTCs. To meet our projected construction milestones, we will need to provide several months' advanced notice to our suppliers and contractors. Therefore, to meet our commitments and keep the projects on track to ensure qualification for 100 percent of the PTCs, we respectfully request that the Commission grant the requested ADP in July 2017.

[13] The Consolidated Appropriations Act, 2016 (H.R. 2029, Sec. 301).

4. *Interconnection and Transmission*

Interconnection and other transmission risks can be some of the largest development risks associated with any wind development. All generation projects, including each of our four self-build projects, are subject to Attachment X of the MISO Tariff, Generator Interconnection Procedures (GIP), which determine the network upgrades that will be required to interconnect a certain project to the MISO transmission system. Pursuant to the GIP, wind projects are assigned to one of the two annual Definitive Planning Phase (DPP) cycles, according to the date each project satisfies all of the requirements to enter a particular cycle.[14] MISO is currently studying the February 2016 DPP. The DPP cycle for each of our projects is identified below in the Description of Wind Portfolio Projects section.

Estimating potential network upgrade costs for projects in upcoming DPP cycles has always involved some level of uncertainty, but is more challenging today than in the past. This is largely due to (1) the amount of wind generation requesting to be added to the MISO system; (2) the delays associated with processing of the MISO interconnection queue; (3) the way that upgrades and their costs are assigned to projects in the queue; and (4) the number of projects that actually move forward once the studies are complete. For example, if MISO were to determine that a significant network upgrade (such as a new transmission line) were required for the August 2015 DPP cycle, it would apportion the costs of that upgrade to the projects within that DPP cycle. Each individual project developer would then decide whether to proceed with their project in light of the assigned network upgrade costs. If some of the projects withdraw their interconnection application from MISO, the costs of the network upgrades are reallocated to the remaining projects in that DPP cycle. If all projects—or enough to eliminate the need for the upgrade within a DPP cycle—drop out, then the network upgrade is not completed during that cycle and will likely get passed onto the next DPP cycle.

In this way, network upgrades can "cascade" through the MISO queue depending on whether projects ahead in the queue decide to proceed with their projects and the assigned upgrades, or withdraw their interconnection applications due to the upgrade costs. This cascade effect has also required MISO to restudy projects later in the MISO queue to determine how to reallocate network upgrades and costs when earlier projects withdraw. This process—combined with the increased number of total projects in the MISO queue—has created significant uncertainty for any project that

[14] DPP cycle requirements are defined in Section 8.2 of MISO's Attachment X and include providing DPP entry milestone, technical data requirements, and study deposits.

does not already have a signed interconnection agreement.[15] Notably, this uncertainty will apply to both our self-build projects and to any project bids received in the RFP process that do not already have a signed interconnection agreement.

We have addressed the risks associated with the MISO queue and network upgrades in two ways. First, we have analyzed each of our projects and their respective positions in the MISO queue, and we have included a good-faith estimate of capital costs for network upgrades for certain projects. We identify these estimated interconnection costs in the Description of Wind Portfolio Projects section below, and have included these estimates in both our capital costs and our LCOE calculations for each project. Second, as we did in connection with the Border Winds project,[16] we have negotiated contractual rights in each of our site PSAs that give us the ability to terminate the contracts if network upgrade costs exceed a predetermined amount in each contract, making the project unviable.

5. Balance of Plant Construction Contracts

As part of our development of these four self-build projects, we will enter into BOP construction contracts with third-party construction companies experienced in wind project construction. A BOP contract is the agreement with a third-party contractor to complete the BOP construction – namely installing the wind turbines and associated facilities. The BOP contracts will be fixed-price contracts, which will minimize schedule and cost risk.

To that end, on February 15, 2017, we issued a firm-price RFP for construction companies to provide bids to provide BOP services in support of our self-build projects. The scope of the BOP contracts will include installation of the wind turbines and construction of the site infrastructure. Site infrastructure includes access roads, turbine foundations, an electrical cable collection system, collection substations, and an operations and maintenance building. The RFP bids were due to be submitted to us by March 27, 2017, which will support the completion of all proposed projects before the 2020 PTC deadline.

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[15] On October 21, 2016, MISO submitted proposed revisions to its GIP and GIA contained in Attachment X, proposing changes to improve the timeliness and efficiency of its queue. *Midcontinent Indep. Sys. Operator, Inc.*, FERC Docket No. ER17-156, MISO QUEUE REFORMING FILING (Oct. 21, 2016). FERC accepted MISO's proposed tariff revisions, subject to condition, to be effective January 4, 2017. *Midcontinent Indep. Sys. Operator, Inc.*, FERC Docket No. ER17-156, ORDER ACCEPTING TARIFF REVISIONS SUBJECT TO CONDITION (Jan. 3, 2017).

[16] *In the Matter of the Petition of N. States Power Co. for Approval of the Acquisition of 150 MW of Wind Generation*, Docket No. E002/M-13-716, PETITION (Aug. 9, 2013).

C. Request for Proposal Process

On September 22, 2016, the Company issued an RFP seeking up to 1,500 MW of wind generation projects and giving potential developers until October 25, 2016 to provide RFP responses. The response to the RFP was robust: 95 proposals associated with 48 projects from 17 bidders totaling nearly 10,000 MW of nameplate wind generation capacity. The bids included 64 PPA proposals, 28 BOT proposals, and three proposals that combined both structures. The pricing included in many of the RFP responses was attractive with more than 30 responses below $22/MWh on a LCOE basis from 13 developers totaling approximately 5,600 MW of capacity. The RFP process resulted in successful contract negotiations of four projects totaling 800 MW of installed wind capacity.

Our RFP process was consistent with the several past RFPs we have issued to acquire wind generation. In this process, the Company issues an RFP, evaluates the bids received, selects proposals from among the bidders, negotiates projects with the selected developers, and presents the results to the Commission for approval. Below we discuss this process in more detail.

1. *Independent Auditor*

On August 2, 2016, the Company engaged Leidos Engineering, LLC (Leidos or the Auditor) as an independent auditor. The independent audit began on August 2, 2016, with the development of RFP documents, continued through the evaluation of proposals, and ended on December 9, 2016, with the final selection of short-list bidders. The main objectives of the audit were to (1) ensure that RFP documents provided sufficient information for bidders; (2) identify and address any potential bias in the evaluation criteria; and (3) verify that the evaluation criteria were applied in a fair manner. The Independent Auditor's Report is provided as an attachment to the Direct Testimony of Company witness Mr. P.J. Martin.

2. *RFP Notice*

We provided notice of the RFP to potential bidders through news media outlets, as well as several government and industry publications and websites. The RFP identified eligible resource options, outlined the treatment of transmission and interconnection costs, explained how multiple proposals for the same project would be treated, and provided a model wind PPA, sample BOT Term Sheet, wind farm technical specifications, and Standard Bidder Forms. The RFP notice also established communication protocols and stated that all responses would be due on October 25,

2016. The documents required for bids were also made available through Xcel Energy's website.

3. Evaluation Process

Bids were received at various points in time between the issuance of the RFP notice and the final due date, but all bids remained sealed until they could be opened together. On October 26, 2016, Xcel Energy's RFP evaluation team opened all bids, catalogued them, and implemented the controls to prevent bid information from biasing the process. These controls included putting in place a conflicts wall between Company personnel developing self-build proposals and evaluating the RFP bids; the securing of all bid documents; and the limiting of access to these documents and the RFP team's analysis to prevent information sharing.

Over the next few weeks, the bids were evaluated in a four-step evaluation:

1) **Completeness and Threshold**: Upon opening the proposals, at least two RFP Resource Planning Team individuals reviewed each proposal to confirm that all information required had been included (completeness review) and that each proposal met the criteria identified in the RFP such as size and location (threshold review). The evaluation team contacted any bidders who did not pass the initial completeness and threshold review and allowed bidders a five-business-day window to address any deficiencies. If the deficiencies were not addressed in a timely manner, the projects were disqualified and no longer considered for short listing. Of the 95 separate proposals received, six were disqualified from further consideration for failing to meet the completeness or threshold requirements.

2) **Levelized Cost of Energy**: Xcel Energy calculated the LCOE for all PPA and BOT proposals that met all completeness and threshold criteria. The objective of the LCOE calculations was to identify projects that will have the lowest total cost and to facilitate a fair comparison between projects. The LCOE for the PPAs was calculated using the proposed energy generated and PPA payments. The LCOE for the BOTs was calculated using a capital-related revenue requirements model developed by Xcel Energy. Some of the inputs for this model were provided by the bidder, including the BOT payment terms, PPA pricing, and net capacity factors/energy production estimates. Estimates for ongoing operations and maintenance (O&M) and capital expenditures were provided by Xcel Energy. Static assumptions related to deferred tax impacts on pricing were used, consistent with the assumptions used in calculating

pricing for the Company's self-build projects. The assumptions used for cost of capital, discount rate, and escalation were developed by Xcel Energy. Ongoing maintenance and capital expenditures for the BOT proposals were determined using a methodology developed by an Xcel Energy engineer who was designated to assist with the RFP process. This methodology was approved by the Auditor prior to the bid submittal deadline to ensure an unbiased approach.

3) **Non-Price Review**: Non-price scoring and qualitative risk assessment measures were intended to supplement the LCOE rankings and determine a preference in the event that LCOE prices are sufficiently close together. For the non-price review, projects were scored in five different areas: (1) generator technology, availability, and warranties; (2) permitting and compliance; (3) site control; (4) transmission; and (5) accounting assessment. Bids were allocated "yes" or "no" answers to questions associated with each area, resulting in an overall non-price score for each project based on the assessment of risks related to these categories.

4) **Final Ranking**: The results of the LCOE review and non-price review were used to develop the final ranking of proposed projects and determine the short-list of projects that would proceed to negotiations. Projects were sorted by LCOE score first. In the event that two projects were within ten percent of each other based on LCOE, the non-price scores were used to determine the ultimate ranking. In other words, prices within ten percent of each other were considered equal and the non-price scores acted as the tie-breaker.

The evaluation was conducted by two separate teams to help maintain an unbiased process. The LCOE evaluation team focused on evaluating all RFP projects based on proposed price and a standardized calculation of LCOE. The non-price team focused on conducting the completeness and threshold and non-price reviews.

The evaluation teams were comprised of Xcel Energy employees and third-party consultants. These RFP team members had not been involved in the development of NSP's self-build proposal, with the exception of one engineer who was responsible for developing the O&M and ongoing capital expenditure cost inputs to the LCOE review for BOT projects. This work was done in consultation with the Auditor to avoid bias.

On December 9, 2016, the Company presented to Leidos its short-list of RFP responses with which it intended to enter into negotiations. Two back-up projects were also identified to potentially replace any short-list projects that might withdraw during the negotiation process.

4. *Negotiations and Due Diligence*

In mid-December 2016, the Company held initial conversations with the parties whose bids were selected for the short-list. In negotiations, the Company reaffirmed that all projects were required to meet the covenants set forth in the RFP notice and that many of the covenants were non-negotiable. Likewise, a bidder's ability to achieve a Commercial Operation Date (COD) and ensure transmission capability sufficient to allow for the full PTC tax benefit was also non-negotiable. The Company also highlighted that bidders were required to meet the security requirements detailed in the model purchase power agreement for PPAs and the purchase and sale terms sheet for BOTs. One of the short-listed bidders formally withdrew its BOT bid from consideration indicating that it would not be able to support the security requirements.

Concurrent with negotiations, the Company began a more detailed due diligence analysis of the technical aspects of each project. The due diligence process found that one project on the Company's initial short-list had significant transmission issues that would substantially increase the cost to NSP and its customers. The bidder was unable to remedy these issues and, as a result, decided to withdraw its bid.

After the withdrawal of these two projects, the Company entered into negotiations with the two projects that had been identified as short-list back-ups. Negotiations with one of the back-up projects was ultimately unsuccessful.

The RFP negotiation process concluded with the Company successfully advancing 800 MW of wind projects: 400 MW of PPA (Crowned Ridge and Clean Energy #1) and 400 MW of BOT (Crowned Ridge and Lake Benton).

D. FINAL WIND PORTFOLIO

The seven projects in the Wind Portfolio represent the results of a careful process to identify the least-cost and compliant projects. Further, we considered the aggregate size of the portfolio resulting from these processes. We recognize that 1,550 MW is a significant amount of wind additions. However, the size of our recommended resource acquisition is driven by the robust RFP response we received and the attractive pricing achieved in our self-build projects, both of which are driven by the current availability of 100 percent qualified PTC projects and the fact that wind is genuinely "on sale." We therefore believe that now is the time to secure these wind resources so we can capture the full PTC benefit for our customers. We further believe that the size of the Wind Portfolio is a prudent way to manage interconnection risk as well.

We also considered the proposed mix of owned projects and purchased power. The proposed Wind Portfolio includes various ownership structures: self-build projects, BOT projects, and PPAs. Xcel Energy already has significant wind generation totaling approximately 2,600 MW: more than 125 wind PPAs totaling more than 1,700 MW of contracted wind generation capacity, and 850 MW of Company-owned wind resources. If the proposed 1,550 MW Wind Portfolio is approved, it will balance our wind generation to 48 percent Company-owned resources and 52 percent PPAs. As set forth in greater detail below, we believe this ownership mix balances the risks and benefits for the Company and our customers consistent with the Commission's stated preference for utility ownership.

The Company also analyzed the economic effects of these seven projects together as an aggregate, as discussed below in Section IV. Our modeling process confirmed the reasonableness and prudence of going ahead with the entire package of seven projects as a portfolio.

In sum, we believe each of the projects comprising the Wind Portfolio is cost-effective and will result in significant customer benefits on its own; we believe the RFP results confirmed the competitiveness of the self-build projects; and we believe that considered in the aggregate, the seven projects comprising the Wind Portfolio are reasonable, prudent, and will bring significant benefits to our customers.

III. DESCRIPTION OF WIND PORTFOLIO PROJECTS

A. SELF-BUILD PROJECTS

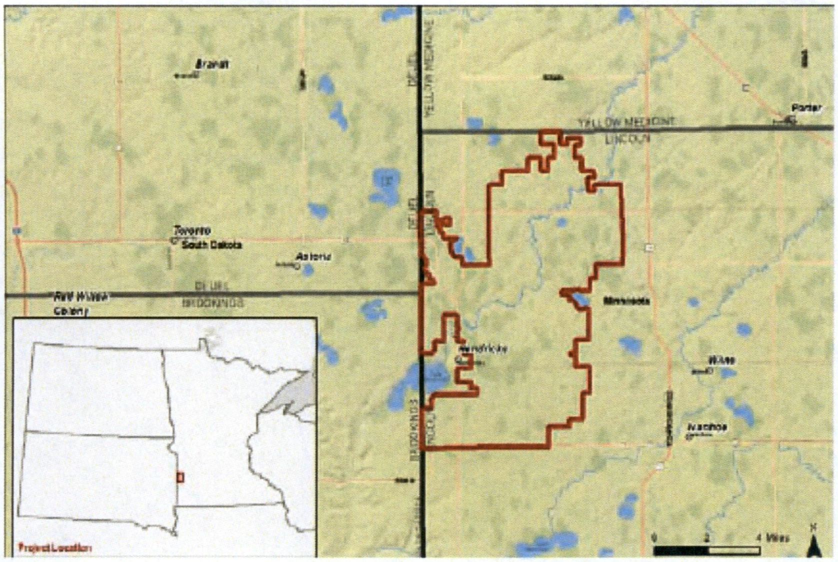
As noted above, there are four self-build projects that are part of the Wind Portfolio: Blazing Star I (200 MW), Blazing Star II (200 MW), Foxtail (150 MW), and Freeborn (200 MW).

1. *Blazing Star I*

a. Project Description

The Blazing Star I project is being developed by Geronimo Energy and is located on approximately 37,200 acres in Hansonville, Hendricks, and Marble Townships, Minnesota.

Figure 1: Blazing Star I Project Location



The Blazing Star I project will have 200 MW of nameplate capacity. Our wind performance analysis predicts a net capacity factor of approximately **[TRADE SECRET BEGINS TRADE SECRET ENDS]**. We project average Annual Energy Production (AEP) of approximately **[TRADE SECRET BEGINS TRADE SECRET ENDS]**, depending on final layout and turbine selection.

The projected LCOE for the Blazing Star I project is **[TRADE SECRET BEGINS TRADE SECRET ENDS]**. Total capital costs for the Blazing Star I project are currently estimated at approximately **[TRADE SECRET BEGINS TRADE SECRET ENDS]**, which includes the estimated transmission upgrades and interconnection costs, as well as anticipated siting and permitting costs.

We expect our primary construction activities on the Blazing Star I project will occur in 2019. However, engineering and some procurement will occur in 2018, as well as some construction pending approval of the various regulatory filings. The current schedule contemplates that wind turbine generators will be delivered to the Blazing Star I site in time to begin turbine erection in 2019. Under the current estimated schedule, we anticipate that commercial operation will be achieved by December 2019. This timeline allows full use of the PTCs because the construction will be completed well within four years from the end of the year in which construction commenced. Variables that may affect the construction schedule include regulatory activity, weather, and the timeliness of interconnection.

b. Transmission Considerations

The Blazing Star I project will interconnect at a new substation on the Brookings County – Lyon County 345 kV line. In March 2015, Geronimo applied with MISO to interconnect Blazing Star I. The Blazing Star I project will be studied under MISO's February 2016 DPP Study Cycle, which started in February 2017. The MISO System Impact Study will determine what transmission constraints must be addressed to maintain system reliability. The Facility Studies that will follow will determine the improvements that must be made – and the cost of those improvements. The results of the Facility Studies will be used to complete the generator interconnection agreement (GIA).[17] Geronimo is responsible for pursuing the necessary approvals to interconnect the Blazing Star I project with the MISO transmission system.

We have undertaken studies to identify and estimate likely transmission network upgrades and interconnection costs for the Blazing Star I project. The likely upgrades that Blazing Star I will have to partially or fully fund include: **[TRADE SECRET BEGINS**

TRADE SECRET ENDS].

Our current estimate for network upgrades is approximately **[TRADE SECRET BEGINS TRADE SECRET ENDS]** and interconnection costs are approximately **[TRADE SECRET BEGINS TRADE SECRET ENDS]**.

While we believe our estimates are reasonably accurate given this stage of development, final costs will not be known until the Facility Studies are complete and a GIA is executed. We will not know whether the project qualifies for Network Resource Interconnection Service (NRIS) from MISO until the System Impact Studies have been completed. However, we have applied for Network Integration Transmission Service (NITS) for the full 200 MW of Blazing Star I. NITS, like NRIS, will allow the project to qualify as a capacity resource upon completion of all required network upgrades. The Blazing Star I point of interconnection on the Brookings-Lyon County 345 kV Line will limit congestion between Blazing Star I and the

[17] We expect the Facility Studies to be completed within the next twelve months, with a signed GIA to follow thereafter.

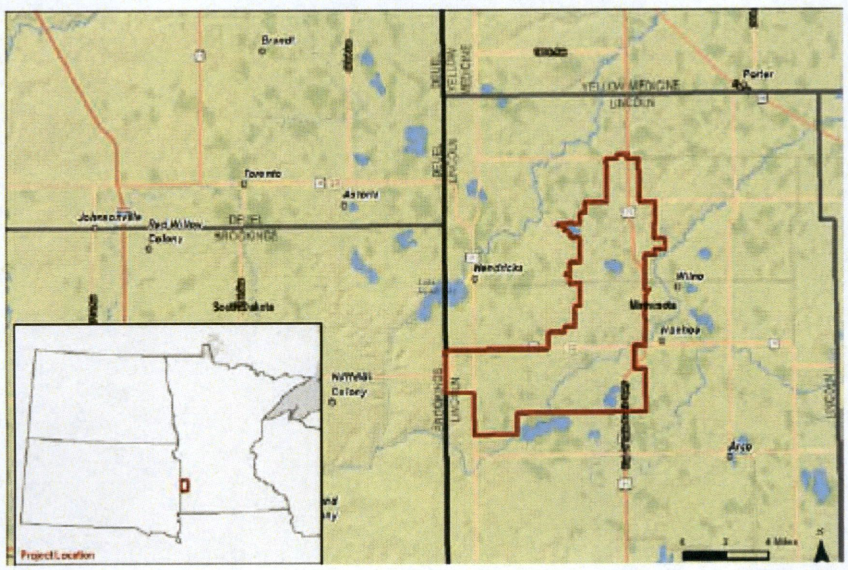
Company's load, and should result in reasonably limited levels of curtailment. The project's expected late 2019 in-service date also allows ample time to construct many of the required network upgrades.

2. *Blazing Star II*

a. Project Description

The Blazing Star II project is also being developed by Geronimo Energy. It extends the Blazing Star I project footprint east and south, on approximately 30,000 acres of predominantly active crop land.

Figure 2: Blazing Star II Project Location



The Blazing Star II project will have 200 MW of nameplate capacity. Our wind performance analysis predicts a net capacity factor of approximately **[TRADE SECRET BEGINS TRADE SECRET ENDS]**. We project average AEP of approximately **[TRADE SECRET BEGINS TRADE SECRET ENDS]**, depending on final layout and turbine selection.

The projected LCOE for the Blazing Star II project is **[TRADE SECRET BEGINS TRADE SECRET ENDS].** Total capital costs for Blazing Star II are currently estimated at approximately **[TRADE SECRET BEGINS TRADE SECRET ENDS]**, which includes the estimated transmission upgrades and interconnection costs, as well as anticipated siting and permitting costs.

We expect our primary construction activities on the Blazing Star II project will occur in 2019 and early 2020. Engineering and some procurement will occur in 2018 and early 2019. The current schedule contemplates that wind turbine generators will be delivered to the Blazing Star II site in time to begin turbine erection in 2020. Under the current estimated schedule, we anticipate that commercial operation will be achieved by September 2020. This timeline allows full use of the PTCs, because the construction will be completed well within four years from the end of the year in which construction commenced. As with Blazing Star I, variables that may affect the construction schedule include regulatory activity, weather, and the timeliness of interconnection.

b. Transmission Considerations

The Blazing Star II project will interconnect at the new substation installed for Blazing Star I. Geronimo applied to interconnect Blazing Star II to the Company's transmission system with MISO in May 2016. Blazing Star II will be studied under the MISO August 2016 DPP Study Cycle. The MISO System Impact Study will determine what transmission constraints must be addressed to maintain system reliability. The Facility Studies that will follow will determine the improvements that must be made – and the cost of those improvements. The results of the Facility Studies will be used to complete the GIA.[18] Geronimo is responsible for pursuing the necessary approvals to interconnect Blazing Star II with the upper Midwest transmission system.

We have undertaken studies to identify and estimate likely transmission network upgrades and interconnection costs for the Blazing Star II project. We used these studies to identify expected transmission upgrades that the project will be required to interconnect. The likely upgrades that Blazing Star II will have to partially or fully **[TRADE SECRET BEGINS**

TRADE SECRET ENDS].

Our current estimate for network upgrades is approximately **[TRADE SECRET BEGINS TRADE SECRET ENDS]** and interconnection costs are approximately **[TRADE SECRET BEGINS TRADE SECRET**

[18] We expect the Facility Studies to be completed within the next 18 months, with a signed GIA to follow thereafter.

ENDS].

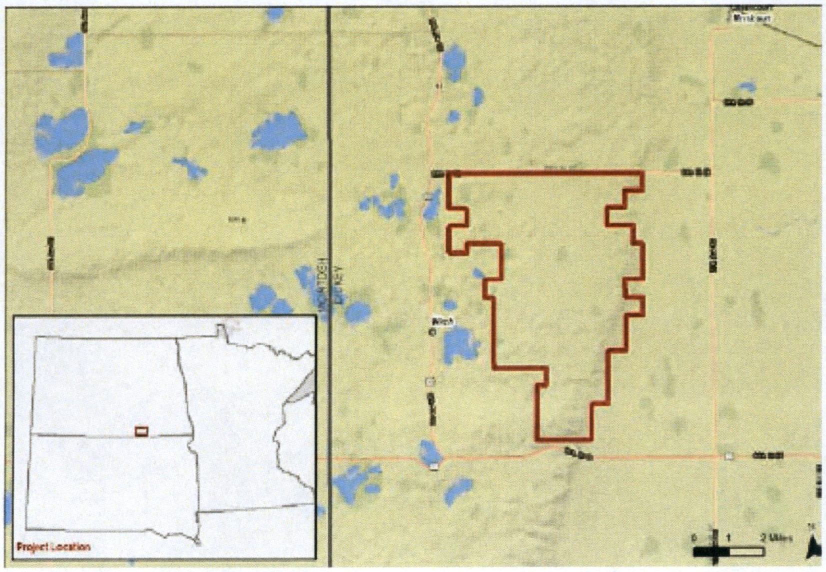
While we believe our estimates are reasonably accurate given the phase of development, final costs will not be known until the Facility Studies are complete and a GIA is executed. We will not know whether the project qualifies for NRIS until the System Impact Studies have been completed. However, we have applied with MISO for NITS for the full 200 MW of the project. NITS, like NRIS, will allow the project to qualify as a capacity resource upon completion of all required network upgrades. Like Blazing Star I, Blazing Star II's point of interconnection on the Brookings – Lyon County 345 kV line will limit congestion between Blazing Star II and the Company's load, and should result in reasonably limited levels of curtailment. The project's expected 2020 in-service date also allows ample time to construct many of the required network upgrades.

3. Foxtail

a. Project Location

The Foxtail wind project is being developed by an affiliate of NextEra Energy Inc. (NextEra), and is located on an approximately 20,000 acre site located 20 miles west of Ellendale, North Dakota. NextEra is the largest developer of wind energy in the United States, with more than 12,400 MW of installed wind capacity in the U.S. and Canada. The site is primarily grazing, farming, and rolling open fields.

Figure 3: Foxtail Project Location



The Foxtail project will have 150 MW of nameplate capacity. Our wind performance analysis predicts a net capacity factor of **[TRADE SECRET BEGINS TRADE SECRET ENDS]**. We additionally project average AEP of approximately **[TRADE SECRET BEGINS TRADE SECRET ENDS]**, depending on final layout and turbine selection.

The projected LCOE for the Foxtail project is **[TRADE SECRET BEGINS TRADE SECRET ENDS]**. Total capital costs for the Foxtail project are currently estimated at approximately **[TRADE SECRET BEGINS TRADE SECRET ENDS]**, which includes the estimated transmission upgrades and interconnection costs as well as anticipated siting and permitting costs.

We expect our primary construction activities on the Foxtail project will occur in 2018 and 2019 with engineering and some procurement occurring in 2017. The current schedule contemplates that wind turbine generators will be delivered to the Foxtail project site in time to begin turbine erection in 2019. Under the current estimated schedule, we anticipate that commercial operation will be achieved by September 2019. This timeline allows Xcel Energy to capture 100 percent of the PTCs, because the construction will be completed well within four years from the end of the year in which construction commenced. Variables that may affect the construction schedule include regulatory activity and weather.

b. Transmission Considerations

The Foxtail project will interconnect at the new substation tapping the Wishek – Ellendale 230 kV line located in eastern North Dakota. NextEra applied to MISO to interconnect the Foxtail project to the Montana-Dakota Utilities (MDU) transmission system in November 2013, connecting to the MDU 230 kV Ellendale–Tatanka transmission line at a new substation. Foxtail was studied under the MISO August 2014 DPP Study Cycle. All MISO System Impact Studies and Facility Studies have been completed and are identified in the executed Foxtail GIA dated August 30, 2016.[19] The GIA shows that the project will be granted 150 MW of NRIS upon completion of all required network upgrades.

The required upgrades include: (1) construction of a new interconnection substation; (2) reconductoring MDU's Ellendale–Foxtail 230 kV transmission line; and (3) reconductoring Western Area Power Administration's (WAPA) Mandan–Ward 230

[19] The GIA is currently being updated to support the specifics of the construction, including the turbines and schedule. We expect no change in the commercial operation date.

kV transmission line. The cost of all upgrades, with the exception of the WAPA upgrade, is known. The final WAPA costs will not be known until a Facilities Study is completed and a facility construction agreement is executed.[20]

We have estimated the costs of the WAPA upgrade based on our knowledge and review of the Mandan–Ward facility, and included it with the known costs from the completed MISO studies. We have estimated the network upgrades for the Foxtail project at approximately **[TRADE SECRET BEGINS TRADE SECRET ENDS]** and interconnection costs at approximately **[TRADE SECRET BEGINS TRADE SECRET ENDS]**.

The Foxtail project interconnects to the Ellendale area 230 kV system, which will be significantly more robust once the Big Stone – Brookings 345 kV Multi-Value Project (MVP) line goes into service in 2017 and the Ellendale – Big Stone 345 kV MVP line goes into service in 2019. This connection also provides a significant 345 kV path to the Twin Cities load center. In addition, as part of the development of this project, all NRIS-related upgrades identified in the interconnection studies will be constructed. These upgrades include the 230 kV line between the Foxtail substation and the Ellendale system, which will strengthen our connection to the Twin Cities and load in North Dakota. These connections will also limit congestion between the Foxtail project and the load, which should result in lower curtailment. The project's expected 2019 in-service date also allows ample time to construct many of the required network upgrades.

c. North Dakota Considerations

As a project located in North Dakota, there is a rebuttable presumption that Foxtail is prudent.[21] The Commission, in determining whether Foxtail is prudent, must also consider the benefits of having the resource addition located in North Dakota.[22] Xcel Energy will apply for a Certificate of Public Convenience and Necessity (CPCN) for this project and also will petition to transfer the Certificate of Site Compatibility (CSC) approved for NextEra for this project closer to its completion and before closing the MSA with NextEra.

Construction of the Foxtail project will bring significant economic benefits to North Dakota. Approximately 150 workers will be employed during the construction phase,

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[20] The WAPA system is in the SPP region rather than the MISO region, so facilities upgrades in both MISO and SPP must be studied and potentially constructed.

[21] *See* N.D.C.C. § 49-05-16(7).

[22] *See* N.D.C.C. § 49-05-16(1)(d).

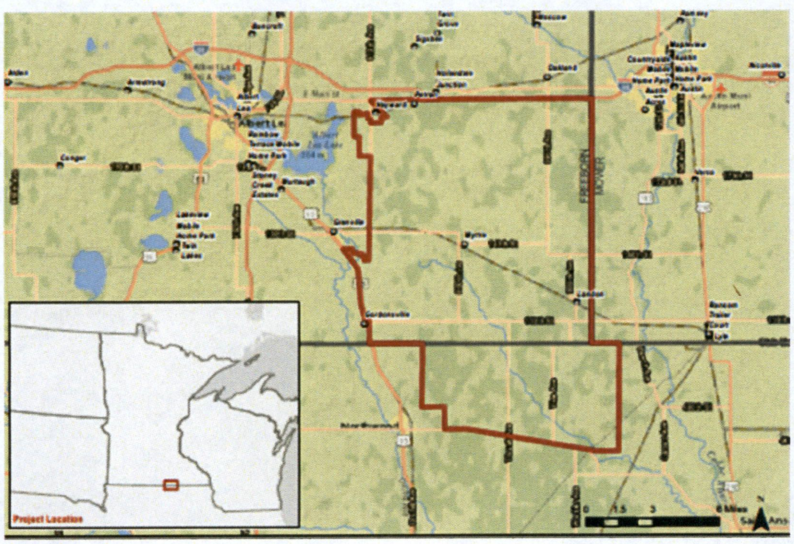
and there will be approximately 8 full-time jobs connected to the project once it is operational. The construction activity will result in activity for local businesses (stores, hotels, services, housing, etc.) and sales and use tax contributions to the State of North Dakota. The landowners will receive payment for use of their land, and the project will generate several hundred thousand dollars of property taxes each year for the State of North Dakota.

4. *Freeborn*

a. Project Description

The Freeborn wind project is being developed by an affiliate of Invenergy Wind Development LLC, and is located on an approximately 40,000 acre site east of Glenville, Minnesota—partially in Minnesota's Freeborn County and partially in Iowa's Worth and Mitchell Counties.

Figure 4: Freeborn Project Location



The Freeborn project will have 200 MW of nameplate capacity. Our wind performance analysis predicts a net capacity factor of approximately **[TRADE SECRET BEGINS TRADE SECRET ENDS]**. We additionally project average AEP of approximately **[TRADE SECRET BEGINS TRADE SECRET ENDS]**, depending on final layout and turbine selection.

The projected LCOE for the Freeborn project is **[TRADE SECRET BEGINS TRADE SECRET ENDS]**. Total capital costs for the Freeborn project are currently estimated at approximately **[TRADE SECRET BEGINS TRADE SECRET ENDS]**, which includes the estimated transmission upgrades and interconnection costs as well as anticipated siting and permitting costs.

Land acquisition is currently underway and expected to be completed later this spring. We currently expect that approximately 50-75 MW of this project—including its point of interconnection—will be located in Minnesota's Freeborn County and that the remaining 125-150 MW will be located in Iowa's Worth and Mitchell Counties.

We expect our primary construction activities on the Freeborn project will occur in 2020, with engineering and some procurement in 2018 and 2019. The current schedule contemplates that wind turbine generators will be delivered to the site in time to begin turbine erection in 2020. Under the current estimated schedule, we anticipate that commercial operation will be achieved by early December 2020. This timeline allows full use of the PTCs because the construction will be completed well within four years from the end of the year in which construction commenced. Variables that may affect the construction schedule include regulatory activity, weather, and the timeliness of interconnection.

b. Transmission Considerations

In November 2014, Invenergy applied to interconnect the Freeborn project to ITC Midwest's transmission system. The Freeborn project will interconnect at ITC Midwest's existing Glenworth 161 kV substation located in southeastern Minnesota. The Freeborn project was studied under MISO's February 2015 DPP Study Cycle. All MISO System Impact Studies and Facility Studies are complete, and the GIA is under negotiation.

While final interconnection and transmission upgrade costs will not be known until the GIA is executed, upgrades identified to date include: **[TRADE SECRET BEGINS (**

TRADE SECRET ENDS]. Invenergy is responsible for pursuing the necessary approvals to interconnect Freeborn with the upper Midwest transmission system.

We have estimated the costs of transmission network upgrades and interconnection costs for the Freeborn project identified through the MISO studies process, and included them in our project costs. We have estimated the network upgrades at approximately **[TRADE SECRET BEGINS TRADE SECRET ENDS]** and interconnection costs at approximately **[TRADE SECRET BEGINS**

TRADE SECRET ENDS], based on our knowledge and review of the facilities involved and included this cost in our estimate.

The Freeborn project will interconnect in an area where major 345 kV MVP line expansion is underway. Freeborn will benefit from completion of the Huntley – Ledyard – Kossuth County and the Ledyard – Colby – Killdeer 345 kV MVP lines scheduled to be in service in 2018. These lines will provide additional transmission outlet for Freeborn and the other wind projects in the area, reducing congestion. Like Foxtail, we chose to fund and construct all NRIS-related upgrades required under the GIA as part of our development of the project, which is expected to minimize local congestion and result in lower curtailment.

B. Build-Own-Transfer and PPA Projects

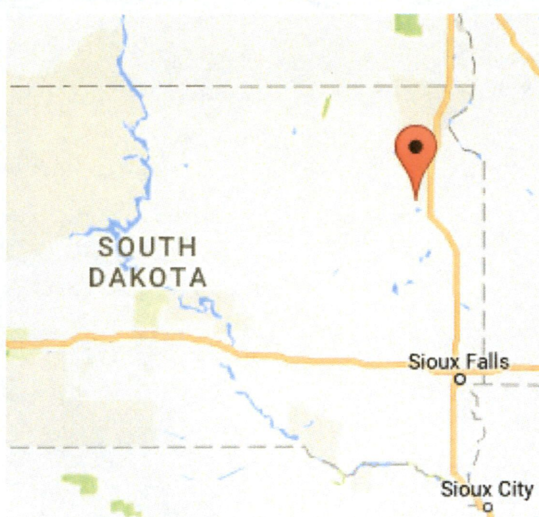
As noted above, the Wind Portfolio includes three BOT and PPA projects: Crowned Ridge (which is a combined BOT and PPA project totaling 600 MW), Lake Benton (a 100 MW BOT project), and Clean Energy #1 (a 100 MW PPA project).

1. Crowned Ridge

a. Project Description

The Crowned Ridge wind project will be a 600 MW (300 MW PPA and 300 MW BOT) wind energy generation facility located in Codington, Deuel, and Grant Counties in South Dakota.

Figure 5: Crowned Ridge Project Location



Land acquisition is currently underway and expected to be completed by March 2017. The anticipated COD is the fourth quarter of 2019. The Crowned Ridge project will be built by NextEra.

The Crowned Ridge project has been offered into the RFP in two parts: a BOT with NSP purchasing the project upon completion for **[TRADE SECRET BEGINS TRADE SECRET ENDS]**, which includes the total purchase price, Xcel Energy's direct costs, and AFUDC, and a PPA with the purchase price of electric energy starting at **[TRADE SECRET BEGINS TRADE SECRET ENDS]**. The combined BOT and PPA bids equate to an LCOE of **[TRADE SECRET BEGINS TRADE SECRET ENDS]**. The LCOE for the BOT-only portion of the bid amounted to **[TRADE SECRET BEGINS TRADE SECRET ENDS]**. The LCOE for the PPA-only portion of the bid amounted to **[TRADE SECRET BEGINS TRADE SECRET ENDS]**.

The BOT portion of the Crowned Ridge wind farm will have 300.6 MW of nameplate capacity while the PPA will have 300 MW of nameplate capacity. The construction and permitting timeline are consistent with the ability to achieve 100 percent PTC value on the full nameplate proposed by the bidder.

b. Transmission Considerations

The point of interconnection for the Crowned Ridge project will be Otter Tail Power's Big Stone South 230 kV substation near Big Stone City, South Dakota.

For purposes of the MISO interconnection study cycle, the Crowned Ridge project has three separate requests, each accounting for 200 MW of the project's total capacity. The first was submitted as part of the February 2015 MISO study group. For this first request, the full System Impact Study has been finalized and the GIA was executed and made effective as of January 8, 2016. All costs associated with this portion of the Crowned Ridge project have been included in NextEra's bid, giving transmission certainty on this portion of the project.

The second interconnection request was studied **[TRADE SECRET BEGINS TRADE SECRET ENDS]**. All MISO System Impact Studies are complete and Facility Studies are ongoing. GIA negotiations will begin upon completion of the Facility Studies. We believe this will be completed by **[TRADE SECRET BEGINS TRADE SECRET ENDS]**. While the final interconnection costs associated with this portion of the

Crowned Ridge project are not final, a review by Excel Engineering as to the reasonableness of the estimated transmission costs provided by NextEra supports the proposal.

The third interconnection request of the Crowned Ridge project will be evaluated **[TRADE SECRET BEGINS TRADE SECRET ENDS]**. Like the previous portion, this study will identify all required transmission upgrades required for the project to interconnect to the transmission grid. We expect that the interconnection agreement will be executed upon completion of the System Impact Study, which we believe will be completed by **[TRADE SECRET BEGINS TRADE SECRET ENDS]**. Excel Engineering did not provide an estimate of anticipated interconnection and upgrade costs for this portion of the project as this portion was not yet formally in the MISO queue.

In summary, the first 200 MW portion of Crowned Ridge has transmission cost certainty as a result of the executed GIA, and we believe that the MISO queue position of the second portion is reasonable, which reduces transmission interconnection risks. We also believe that the reasonableness of the transmission cost estimates, along with the project's positions in the MISO queue, support the project's ability to achieve a COD sufficient to realize the full benefit of PTCs. Finally, while the last 200 MW portion is subject to more risk and uncertainty, **[TRADE SECRET BEGINS TRADE SECRET ENDS]**.

The Crowned Ridge project will interconnect in an area where major 345 kV MVP line expansion is underway. Crowned Ridge will benefit from completion of the Big Stone – Brookings 345 kV MVP line that goes into service in 2017 and the Ellendale–Big Stone 345 kV MVP line that goes into service in 2019. These lines will provide additional transmission outlet for Crowned Ridge and the other wind projects in the area, reducing congestion. The significant 345 kV path east to the Twin Cities load center will limit congestion between Crowned Ridge and the load. The project's expected 2019 in-service date also allows ample time to construct many of the required network upgrades.

2. *Lake Benton*

a. Project Description

The Lake Benton BOT wind project will be a 100 MW wind energy generation facility located in Pipestone County southeast of Lake Benton, Minnesota.

Figure 6: Lake Benton Project Location

The Lake Benton project is a repowering of the existing Lake Benton II wind facility, which has been in operation since May 2000 and currently contracts its power through a PPA to NSP. Easements for the operating site are currently held by NSP under the current PPA and, as a result, land acquisition is already complete. The anticipated COD is fourth quarter 2019. The project will be built by NextEra.

The Lake Benton project has been offered into the RFP as a BOT with NSP purchasing the project upon completion for **[TRADE SECRET BEGINS TRADE SECRET ENDS]**, which includes the total purchase price, Xcel Energy's direct costs, and AFUDC, along with other ownership costs amounts to an LCOE of **[TRADE SECRET BEGINS TRADE SECRET ENDS]**. We note that this generation facility is currently selling power to NSP through a PPA at a higher cost than the expected LCOE for the proposed project. The current cost of the contract is **[TRADE SECRET BEGINS TRADE SECRET ENDS]** demonstrating a reduction in cost of about **[TRADE SECRET BEGINS TRADE SECRET ENDS]** when compared to the LCOE of the proposed project. These savings will benefit Xcel Energy's customers.

The construction and permitting timeline are consistent with the ability to achieve 100 percent PTC value on the full nameplate proposed by the bidder. The current PPA will go into suspension at a date to be determined prior to the start of construction on the new facility. Formal decommissioning of the existing facility will occur sometime in early 2019.

b. Transmission Considerations

The point of interconnection for Lake Benton will be NSP's Buffalo Ridge and Chanarambie substations. The project will utilize the grandfathered interconnection rights assigned to Lake Benton Power Partners under the MISO precursor, the Mid-Continent Area Power Pool (MAPP), but will be required to obtain a generator interconnection agreement under MISO's material modification process. The bid proposal initially contemplated the point of interconnection being changed to the Brookings County 345 kV substation, however, the project currently intends to instead use the existing interconnection associated with the current Lake Benton II PPA, which results in decreased transmission risk for the project. The Buffalo Ridge 115 kV system has strong connections to the Twin Cities load center in MISO through a number of major 345 kV facilities, and thus has sufficient transmission capacity to accommodate all interconnected generation, including the repowered Lake Benton project.

3. ALLETE Clean Energy #1

a. Project Description

The Clean Energy #1 project will be a PPA 100 MW wind energy generation facility developed by ALLETE Clean Energy (ACE). It will be located northeast of Glen Ullin, North Dakota, in Mercer and Morton Counties, about 40 miles west and 8 miles north of Bismarck. The project is adjacent to the Bison Wind projects that were developed by ACE affiliate Minnesota Power.

Figure 7: Clean Energy #1 Project Location

Land is currently secured under option agreements, which will be converted to long-term easement agreements prior to construction starting. Construction is expected to be completed in time for a COD in the fourth quarter of 2019. ACE has developed approximately 645 MW of installed wind capacity in five states since 2011, with 537 MW of that currently owned and operated by ACE.

The Clean Energy #1 project has been offered into the RFP as a PPA, with NSP purchasing the power from the project at a price of **[TRADE SECRET BEGINS**

TRADE SECRET ENDS]. The LCOE for this project amounts to **[TRADE SECRET BEGINS** **TRADE SECRET ENDS]**.

The LCOE for Clean Energy #1 also includes 5 years of additional estimated wind energy values, as the economic modeling was conducted to evaluate a 25-year period. This was done to ensure a fair comparison between the 20-year Clean Energy #1 PPA and BOT and PPA projects with 25-year lives. The Clean Energy #1 project will have 105.6 MW of nameplate capacity. The construction and permitting timeline are consistent with the ability to achieve 100 percent PTC value.

b. Transmission Considerations

The point of interconnection will be Minnesota Power's Square Butte substation near Center, North Dakota in Oliver County. ACE will enter into an agreement with Minnkota Power Cooperative (MPC) to utilize MPC's bus bar at the Square Butte substation to deliver the MISO point of interconnection. The Clean Energy #1 project was initially submitted for an interconnection study by ACE affiliate

Minnesota Power. The full System Impact Study has been finalized and the GIA was executed and dated May 8, 2014. Minnesota Power plans to transfer the GIA to ACE (subject to regulatory approval) in order to meet its obligations under the PPA. All costs associated with this portion of the Clean Energy #1 project have been included in ACE's bid, giving transmission certainty on this portion of the project.

The Clean Energy #1 project has transmission cost certainty as a result of the executed GIA, which reduces transmission interconnection risks. We believe that the reasonableness of the transmission cost estimates, along with the project's existing GIA, will not impact the project's ability to achieve a COD that realizes the full benefit of PTCs. Additionally, the PPA dictates that ACE will absorb the generation interconnection cost risks, mitigating the risks associated with the project for NSP and its customers.

The Clean Energy #1 project will interconnect in an area where major 230 kV and 345 kV MVP lines exist with connections to Company load in North Dakota and Minnesota. In addition, the Big Stone – Brookings 345 kV MVP line goes into service in 2017 and the Ellendale – Big Stone 345 kV MVP line goes into service in 2019, which will benefit the Clean Energy #1 project and reduce congestion.

c. North Dakota Considerations

As a project located in North Dakota, there is a rebuttable presumption that Clean Energy #1 is prudent.[23] The Commission, in determining whether Clean Energy #1 is prudent, must also consider the benefits of having the resource addition located in North Dakota.[24] As a PPA project, Xcel Energy does not require a CPCN but does require an ADP to recover the costs of the project through its Fuel Cost Rider (FCR).

Construction of the Clean Energy #1 project will bring significant economic benefits to North Dakota. Approximately 100 workers will be employed during the construction phase, and there will be about 6 full-time jobs connected to the project once it is operational. The construction activity will result in activity for local businesses (stores, hotels, services, housing, etc.) and sales and use tax contributions to the State of North Dakota. The landowners will receive payment for use of their land, and the project will generate several hundred thousand dollars of property taxes each year for the State of North Dakota.

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[23] *See* N.D.C.C. § 49-05-16(7).

[24] *See* N.D.C.C. § 49-05-16(1)(d).

IV. ECONOMIC ANALYSIS OF THE WIND PORTFOLIO

A. OVERVIEW

To evaluate the economic impact of the proposed Wind Portfolio, we used the Strategist resource planning model. Strategist simulates the operation of the NSP System and estimates the total cost of energy over the life of the projects on a present value basis. We use Strategist to test results under a range of input assumptions. Through it, we simulated the operation of the NSP System through 2053, with and without the addition of the 1,550 MW of wind generation proposed in the Wind Portfolio.

Wind generation creates a financial benefit by reducing fossil fuel purchases and energy purchased from the market thereby reducing the Company's overall fuel and purchased power costs. The Strategist analysis accounts for these cost savings as well as the impact of the capital commitments or PPA payments associated with the wind generation additions. As required by North Dakota statute, no environmental externality costs are included in the analysis.[25]

We believe we have taken a conservative approach in developing the base assumptions as well as the varied input assumptions (also known as "sensitivities") used to analyze the Wind Portfolio. The results of the Strategist analysis show that the Wind Portfolio will result in net savings for our customers under all sensitivities conducted.

B. STRATEGIST ANALYSIS

1. PVRR Savings

We evaluated the proposed wind projects both on an individual basis and as a total portfolio, in order to analyze the benefits of each individual project as well as the combined benefits of the entire 1,550 MW Wind Portfolio. The results of the Strategist analysis show that these new wind resources will result in net savings for our customers under all sensitivities analyzed. Table 1, below, shows the PVRR savings. The PVRR savings do not include CO_2 costs or other externality costs and do not include Surplus Capacity Credits.

[25] *See* N.D.C.C. § 49-02-23.

Table 1: Incremental PVRR Savings from Reference Case ($millions)

	PVRR				
	Mkts On	Mkts Off	Mkts Off	Mkts On	Mkts Off
	Base	Dump Energy Credit	No Dump Energy Credit	Low Gas	Preferred Plan Renewables
Reference Case	0	0	0	0	0
BOT Crown Ridge	(372)	(342)	(317)	(271)	(291)
PPA Crown Ridge	(361)	(331)	(306)	(260)	(280)
Lake Benton	(77)	(92)	(90)	(39)	(96)
Clean Energy	(38)	(42)	(36)	(8)	(64)
Blazing Star 1	(279)	(233)	(216)	(216)	(191)
Blazing Star 2	(197)	(188)	(174)	(122)	(184)
Foxtail	(161)	(149)	(138)	(106)	(154)
Freeborn	(192)	(184)	(173)	(120)	(181)
All	(1,599)	(1,541)	(1,319)	(1,053)	(1,411)

As shown in Table 1, the proposed Wind Portfolio provides significant benefits. In fact, all projects provide significant savings to our customers over their lives, both individually and as a portfolio, even under the conservative sensitivity cases studied.

We have also analyzed the projects where Strategist does not allow market sales or purchases (Markets-Off). This is consistent with past analysis of resource additions and the modeling conducted in past IRPs. In a Markets-Off optimization, the model does not consider the ability to make market purchases and sales. Thus, the cost-effectiveness of resource additions are based on their effectiveness in serving only system (not market) needs.

We have also included an extreme sensitivity that does not allow any market sales or purchases and does not give any value to the "dump energy."[26] Under this sensitivity, all benefits come from savings attributable to reduced system fuel costs instead of sale of excess energy produced by the wind. Even under this extreme case, the benefits of the Wind Portfolio are significant at $1.3 billion on a PVRR basis for the NSP System.

We also considered other sensitivities, including varying project lives, variations in O&M and capital costs, variations in wind capacity factors, and variations in natural

[26] Under a Markets-Off view, energy in excess of system needs that is produced by non-dispatchable and must-run resources is considered "dump energy" in that it is "dumped" into the market and valued at a market pricing to offset system costs.

gas prices. These are presented in Table 2, below. Under all of the different sensitivities, the benefits of the Wind Portfolio remained significant.

Table 2: Additional Sensitivity Analysis

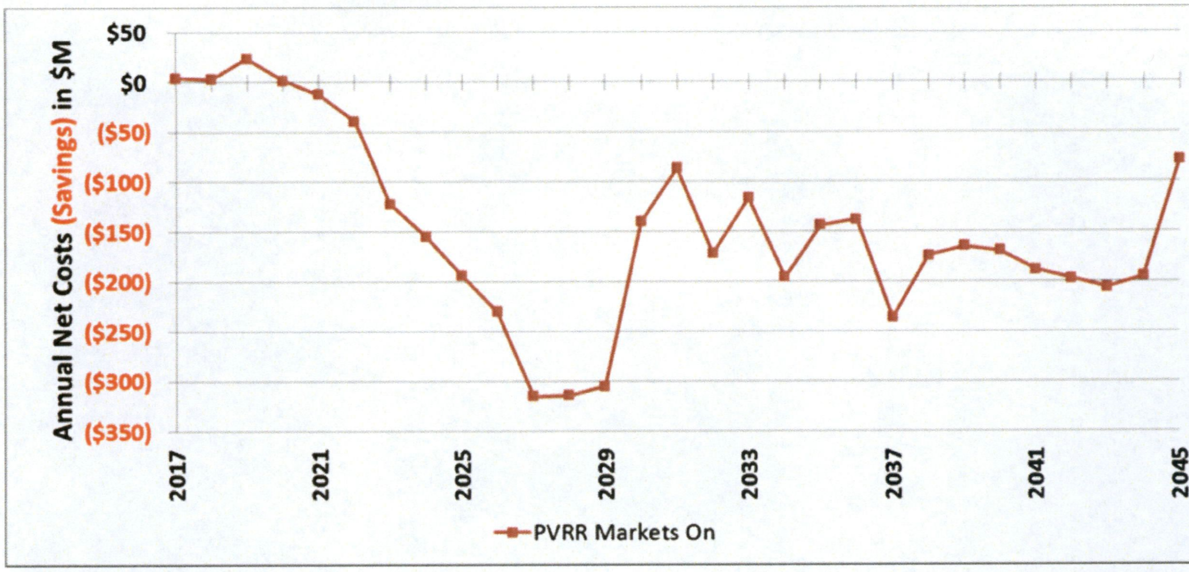
	PVRR					
	Mkts Off	Mkts Off	Mkts Off	Mkts Off	Mkts Off	Mkts Off
	30-Year Life	20-Year Life	+5% Cap Factor	-5% Cap Factor	High On-Going Costs	Low On-Going Costs
Reference Case	0	0	0	0	0	0
BOT Crown Ridge	(430)	(253)	(429)	(254)	(324)	(360)
PPA Crown Ridge	(331)	(331)	(358)	(303)	(331)	(331)
Lake Benton	(109)	(51)	(120)	(62)	(85)	(98)
Clean Energy	(42)	(42)	(49)	(35)	(42)	(42)
Blazing Star 1	(230)	(151)	(292)	(175)	(222)	(244)
Blazing Star 2	(219)	(144)	(247)	(130)	(178)	(199)
Foxtail	(175)	(113)	(195)	(105)	(140)	(157)
Freeborn	(214)	(143)	(242)	(127)	(174)	(195)
All	(1,740)	(1,269)	(1,886)	(1,203)	(1,477)	(1,605)

2. *Savings Over Time*

To understand how the costs (savings) change over time, Figure 8 below visually portrays the annual costs (savings) impacts of the total Wind Portfolio as compared to the Reference Case.[27]

[27] Figure 8 provides system-wide impacts based on the most prevalent ratemaking treatment across our system.

Figure 8: Annual Costs (Savings) Compared to Reference Case



The addition of the proposed wind resources creates a net cost to the NSP System of $23 million in 2019. While the Strategist model relies on the most prevalent ratemaking treatment of the System, actual revenue requirement will be based on the ratemaking treatment utilized in each jurisdiction. Initially, upfront capital costs of the proposed owned projects drive costs higher in the early years, but over the long term, customers receive significant rate benefits from avoided fuel costs and the accrual of PTCs. As shown in Figure 8, customers are expected to see a neutral rate impact by 2020 and will realize significant benefits beyond 2020 for each remaining year of the projects' lives.

3. Levelized Price

An alternate way of assessing the value of the proposed wind to the system is by evaluating the levelized price of the projects and the other costs and benefits associated with them. Levelized prices are a fixed $/MWh price that have the same net present value (NPV) as the actual cost streams generated by Strategist. As mentioned previously, in addition to the direct project costs, the Strategist model also adds cost for wind integration, transmission congestion, and line losses. The primary benefit of the projects is avoided fuel costs and avoided capacity costs. Table 3 illustrates how the levelized costs of the proposed projects are more than offset by the value of avoided generation costs.

Table 3: PVRR Levelized Costs Analysis - $/MWh*

	BOT Crown Ridge	PPA Crown Ridge	BOT Lake Benton	PPA Clean Energy	Self Build Blazing Star 1	Self Build Blazing Star 2	Self Build Foxtail	Self Build Freeborn	Portfolio ALL
	[PROTECTED DATA BEGINS								
LCOE									
									PROTECTED DATA ENDS]
Wind Integration	$0.54	$0.54	$0.54	$0.53	$0.54	$0.55	$0.54	$0.56	$0.54
Wind Congestion	$3.25	$3.25	$3.25	$3.15	$3.25	$3.31	$3.25	$3.32	$3.26
Wind Induced Coal Cycling	$1.48	$1.48	$1.48	$1.58	$1.48	$1.47	$1.48	$1.46	$1.46
Avoided Production and Capacity Costs	($48.85)	($48.88)	($37.54)	($41.55)	($52.50)	($45.24)	($45.02)	($46.44)	($44.54)
Avoided Emission Costs	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	[PROTECTED DATA BEGINS								
Net Cost/(Benefit)									
									PROTECTED DATA ENDS]

* Value for Clean Energy #1 reflects the cost impacts during the 20-year life of the PPA term.

4. *Hedge Benefits*

In addition to the compelling economic benefits, adding additional wind at favorable pricing provides a hedge against future increases in natural gas prices. This is primarily because the wind displaces thermal generation. To illustrate the benefit of these projects, Table 4 shows a base volume of natural gas and the delta avoided by the studied projects.

Table 4: Hedge Value

Total System 2017-2053	Natural Gas *bcf*
Reference Case	6,186
BOT Crown Ridge	(187)
PPA Crown Ridge	(186)
Lake Benton	(27)
Clean Energy	(20)
Blazing Star 1	(176)
Blazing Star 2	(111)
Foxtail	(93)
Freeborn	(107)
All	(716)

C. Estimated Customer Rate Impacts

We expect that soon after initial operation, customers' overall bills will be lower than otherwise as a result of the acquisition of the proposed resources. Based on the results of our Strategist modeling, we expect that beginning in 2021, the cost of the proposed wind projects will be more than offset by decreases in the cost of fuel and purchases and increases in revenues from market sales. To develop our rate impacts analysis, we began with the incremental impact of the wind resources as determined by the Strategist modeling that was conducted. We note that the Strategist model relies on a system-wide calculation of revenue requirement developed by applying the most prevalent ratemaking treatment across our system. Actual revenue requirement will be based on the ratemaking treatment utilized in each jurisdiction. Using the annual system-wide costs impact from Strategist, we then applied a jurisdictional allocator based on a current sales forecast to determine the costs allocated to the North Dakota jurisdiction. The jurisdictional costs were then allocated to classes based on Class Cost of Service Study (CCOSS) allocation factors approved in the Company's last North Dakota rate case order.

Table 5 shows the forecasted incremental annual rate impact of the wind additions through 2022. The values in the table reflect incremental costs or savings as compared to the Reference Case where no wind additions are included. We anticipate the peak cost impacts to occur in 2019 and decline rapidly thereafter as the projects depreciate.

Table 5: Incremental North Dakota Revenue Requirement Impact of Proposed Portfolio in North Dakota, $M

	2017	2018	2019	2020	2021	2022
New Ownership Wind, 1250MW	0.2	0.2	1.7	4.1	5.2	4.0
New PPA Wind, 400MW	0.0	0.0	0.1	1.3	1.3	1.4
Production Cost Savings	0.0	0.0	(0.3)	(2.3)	(3.2)	(3.5)
MISO Purchases	0.0	0.0	(0.1)	(1.4)	(1.4)	(1.2)
MISO Sales	0.0	0.0	(0.2)	(3.0)	(4.3)	(4.6)
Wind Congestion Costs*	0.0	0.0	0.1	0.8	1.1	1.1
Wind Integration Costs	0.0	0.0	0.0	0.1	0.2	0.2
Wind Coal Cycling Costs	0.0	0.0	0.0	0.4	0.5	0.5
Net Costs	**0.2**	**0.2**	**1.3**	**0.1**	**(0.7)**	**(2.1)**

* Congestion Costs reflected as cost adder to wind generation rather than lower generator LMP.

Table 6, below, shows the forecasted incremental impact on average monthly bills in North Dakota based on the revenue requirement impacts show in Table 5. It is important to note that the actual impact on each customer class will vary depending on the specific ratemaking treatment in each jurisdiction. We have provided an estimated impact below. The below table shows that the monthly cost impact to the average residential customer is expected to peak in 2019 at $0.44 per month.

Table 6: Incremental Average Monthly Bill Impacts

Customer Class	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Residential	$0.08	$0.05	$0.44	$(0.11)	$(0.41)	$(0.92)
Commercial Non-Demand	$0.12	$0.08	$0.66	$(0.16)	$(0.60)	$(1.36)
C&I Demand	$2.69	$1.87	$15.19	$(3.69)	$(13.90)	$(31.44)
Lighting	$0.06	$0.04	$0.31	$(0.11)	$(0.33)	$(7.90)

V. REASONABLE MITIGATION OF RISKS

As with any large generating project, there are risks associated with the development and operation of each of the projects comprising the Wind Portfolio. We believe that we have identified, assessed, and mitigated major risks through prudent contracting practices, and that it is reasonable and in our customers' interest for the Commission to authorize us to proceed with these projects. We discuss each of the primary areas of risk and our mitigating actions in this section.

A. FEDERAL PTC

In order to qualify for 100 percent of the PTC amount, these wind facilities must begin construction in 2016 to qualify for the PTC "safe harbor" and must be completed within four years of the commencement date. As discussed above in Section II.B.3, there are two ways to begin construction for purposes of the safe harbor: (1) commencing "physical work of significant nature" at the project site (or at a factory if the work involves equipment for the project); or (2) incurring at least five percent of the total project cost. With respect to the five percent method, it is important to note that costs are not incurred merely by spending money; the developer must actually take delivery of the equipment either by year-end or within 105 days from incurring the cost. Under either safe-harbor method, the projects must be placed in service within four years from the end of the year that construction commenced.

We believe that all seven of these proposed projects will meet the requirements necessary to qualify for 100 percent of the PTC, and that the risk has been reasonably mitigated.

In both the PPA and BOT agreements, the bidders assume the risk of completing projects in the timeframe required to achieve the full PTC benefit. Risk is further mitigated by the bidders having indicated that they have turbines that qualify for PTCs through safe-harbor mechanisms, as well as Xcel Energy's advance purchase of safe-harbor-qualifying turbines that can also be used for the projects.

For the self-build projects, the Company mitigated the PTC risk by securing enough turbines to support our projects and meet the five-percent safe-harbor requirement in September 2016. In addition, we have developed a comprehensive project schedule that involves the sequenced construction of the four self-build projects to keep the projects on track to ensure qualification for 100 percent of the PTCs.

B. Construction Risks

Our self-build proposals mitigate construction risk by being developed as a group. By managing the projects this way, we will be able to leverage economies of scale in project planning and execution, and reduce the schedule-related risks typically associated with individual projects.

With regard to the BOT proposals, the projects all have agreements that assign construction risk to the bidder. The Company does not purchase the projects until construction is completed. This mitigates risk to the Company and its customers by eliminating any detrimental financial impact prior to the projects' completion. In addition, the parties have also agreed to **[TRADE SECRET BEGINS**

TRADE SECRET ENDS].

With regard to the PPA agreements, NSP is also not obligated to make payments to counterparties prior to the COD of the projects. Also, these agreements have similar provisions to the BOT damage provisions. These damages are recouped in the form of a security requirement paid to NSP in the amount of **[TRADE SECRET BEGINS TRADE SECRET ENDS]**.

Additionally, for the BOT agreements, we have required the bidders to meet our technical criteria for Company-owned facilities. These technical criteria are based on our experience operating similar facilities and compliance with the criteria should mitigate the risk of construction problems or setbacks.

C. Transmission Risks

As discussed above in Section II.B.4, interconnection and other transmission risks can be some of the largest development risks associated with wind generation. Project-specific transmission risks are discussed in the project description sections above. As set forth in those sections, the MISO transmission interconnection process is not yet complete for several of the projects. As a result, there is some uncertainty around the final interconnection costs for the Blazing Star I, Blazing Star II, Lake Benton, Crowned Ridge, and Clean Energy #1 projects.

With regard to BOT and PPA projects, however, we believe this risk has been reasonably mitigated in our agreements with developers, and by prioritizing transmission certainty within the MISO study queue process as a factor in the non-price review.

With regard to the potential for transmission risk for our self-build projects, we have mitigated the risks in two ways, as noted in Section II.B.4 above: (1) we have included a good-faith estimate of capital costs for network upgrades in our overall capital costs and our LCOE calculations for each project; and (2) we have negotiated rights that give us the ability to terminate the contracts if network upgrade costs exceed a predetermined amount.

D. Environmental Risks

1. *Self-Build Projects*

For the self-build projects in the Wind Portfolio, developers are responsible for applicable environmental permits, licenses, and approvals from any governmental authority required under applicable laws for construction, ownership, operations, and maintenance of the site prior to transfer of ownership to NSP. And all other permits will be obtained by the developer prior to construction.

For all four of the self-build projects, pre-construction wildlife studies have been initiated or completed in general accordance with Tiers 1 through 3 of the U.S. Fish and Wildlife Service's (USFWS) Land Based Wind Energy Guidelines. For Freeborn and Blazing Star I & II, these studies support an Avian and Bat Protection Plan (ABPP), which is required by the State of Minnesota. A draft ABPP for Blazing Star I was filed with a draft site permit for the project in late 2016,[28] and ABPPs for Blazing Star II and Freeborn are expected to be developed in coordination with their respective site permit applications, which have not yet been filed. Although the State of North Dakota does not currently require an ABPP for issuance of a CSC, Tier 1 through 3 studies have been completed for the Foxtail project and will be used to characterize risks to wildlife within the framework of a voluntary wildlife conservation strategy created by the developer. Additional consultation with the USFWS on the

[28] *In the Matter of the Application of Blazing Star Wind Farm, LLC for a Site Permit for the up to 200 Megawatt Blazing Star Wind Project in Lincoln Cty., Minn.*, Docket No. IP6961/WS-16-686, SITE PERMIT APPLICATION at Appendix G (Sept. 2, 2016).

self-build projects will occur once transfer of ownership of the self-build projects is complete.

2. *BOT and PPA Projects*

Under the terms of the PPA and BOT agreements, the bidder is responsible for all applicable environmental permits, licenses, and approvals from any governmental authority required under applicable laws for construction, ownership, operations, and maintenance of the facility prior to transfer of ownership to NSP.

Each project is expected to have minimal impact on avian and bat species, based on research that has been performed in the region specific to the environmental impacts of wind energy. ACE has completed the studies related to the ABPP as required by the State of Minnesota and received its permit through the Large Wind Energy Conversion System (LWECS) permitting process. As such, we believe the environmental risk related to this project has been sufficiently mitigated. With regard to the Crowned Ridge and Lake Benton projects, NextEra has begun these studies and will provide the permits once available. Xcel Energy has also conducted its own analysis to assess the risks related to environmental permitting. We believe that these projects are likely to receive the permitting required and will be able to reach commercial operation in the timeline proposed by NextEra.

E. OPERATIONAL RISKS

Once in service, the proposed projects also face operational risks, including uncertainty as to the amount of annual generation and the real-time delivery of that power to our customers, resulting from power production and curtailment. We discuss curtailment generally as one component of operational risk in this section but discuss our assumptions and expectations for each project more specifically in the curtailment section below.

For owned projects (BOT and self-build), the operational risks remain with the Company through its ownership. Additionally, owned projects have some uncertainty in annual costs for operation and maintenance. However, these risks are offset by higher estimated benefits from Company ownership. For example, to the extent that annual generation at the Company-owned projects is lower than expected, the overall cost-effectiveness of the project would decrease. Conversely, however, if annual generation is greater than expected, our customer benefits from the project would increase.

With regard to the PPA projects, the PPAs for Crowned Ridge and Clean Energy #1 are designed to compensate the counterparties for the actual electric energy delivered from the wind farms. This provides a good incentive for the counterparties to properly maintain their turbines and maximize production. With respect to curtailment, wind developers are typically paid by the utility in the event that their project is curtailed. Additionally, our customers will not pay for curtailments associated with emergencies or transmission system maintenance outages. Finally, we identified project-specific curtailment risks during our due diligence for each project, and those risks are discussed in the curtailment section below.

Finally, to incorporate potential operational risks, we have included what we believe to be conservative assumptions in our economic analysis and also included sensitivities that explore the impacts of a number of different downside scenarios. Likewise, we have adjusted capacity factors based on direction from our consultants, and our sensitivity analyses that use even lower capacity factors still demonstrate substantial savings for customers. These risks and assumptions are quantified in the Cost Effectiveness Analysis section of this Application.

F. WIND CURTAILMENT

We expect some level of wind curtailment will occur during the life of all wind projects, which based on our experience and analysis, we expect will be less than four percent over the life of the projects which is consistent with historical curtailment levels. Curtailment is expected to be higher at the outset of the project, and then is expected to decline as new transmission and other changes on the MISO system occur to better accommodate increased wind penetration. The driver of curtailment early-on is generally because the projects go into service before all required transmission facilities are completed – both locally and regionally on the MISO system. Regional congestion is expected to be the largest driver of curtailment over the life of the wind projects.

A significant driver of regional transmission congestion has been the significant concentration of wind facility operations in southern Minnesota and all through Iowa, which is continuing to increase. The required transmission upgrades for some of the new wind projects going into service between 2016 and 2020 will not all be in-service by the time the projects begin producing energy. This will have a negative effect on Locational Marginal Pricing (LMP) in MISO that could potentially also impact real-time wind generation on the NSP System. On the other hand, we expect that significant planned transmission improvements in the region, such as the CapX2020 transmission projects (CapX2020) and the MISO MVPs, will positively impact curtailment of our proposed wind projects by creating additional transmission outlet and reducing local and regional congestion. Ultimately, the amount of curtailment will depend on the in-service timing of the numerous wind generation projects currently in the development queue.

To analyze the potential level of curtailment, we performed PROMOD studies, used historical curtailment data along with knowledge of the transmission system, and reviewed other studies related to this issue. Our PROMOD simulations indicated curtailments will be minimal for NSP's proposed projects. The historical curtailment data indicated that wind curtailment is small compared to the total wind generation delivered: between 2003 and 2016, the amount of curtailment varied year by year, but eventually stabilized below 3.8 percent. In addition, the RFP requested that the bidders provide an analysis and discussion of the issues surrounding congestion and expected curtailments pertaining to their project(s). The analysis provided by the winning bidders (and other bidders not chosen under this RFP) all indicated minimal curtailment risk for projects.

Based on all of these analyses, we expect curtailments to range from as low as two percent to as high as six percent. Curtailment rates may initially be high and then decline to a lower rate such as the two percent in the MRITS. Therefore, our estimate is that over the lifetime of these wind projects the overall average curtailment rate will be approximately four percent.

G. Risk Reduction Through Diversity

The Wind Portfolio contains a mix of both PPA and Company-owned resources. Specifically, 1,150 MW will be Company-owned and 400 MW will be PPAs.

PPAs and utility-owned projects each come with distinct bundles of risks and benefits. For this reason, we believe a mix of ownership structures is the best way to balance project risks and ensure that our customers realize optimal short- and long-term benefits from the additions. A balance of ownership structures ensures that our customers obtain the benefits of each ownership structure, and that the cost and risks are appropriately balanced. Simply put, one of the most important advantages of the Wind Portfolio is that by diversifying locations, ownership structures, and timelines, the risks associated with any one project are minimized and balanced by the existence of the other projects.

VI. PRUDENCE OF THE WIND PORTFOLIO

The Company's acquisition of the Wind Portfolio is prudent. We have evaluated this proposed 1,550 MW resource addition from both a long-term perspective and from a near-term rate impact perspective. We used the Strategist model to estimate the cost of energy from our system over the life of the projects. And we have evaluated the risks associated with the development of all of the projects. Based on all of this analysis, we believe that it is reasonable and in our customers' interests for the Commission to grant an ADP for these projects. We also note that pursuant to N.D.C.C. § 49-05-16(7), the Foxtail and Clean Energy #1 projects are presumed to be prudent.

Our analysis, with its conservative assumptions, shows that the wind projects we propose will result in significant cost savings to customers. Over the term of the contracts, we anticipate that customers will save, conservatively, approximately $1.6 billion. Even if natural gas prices grow at only half the forecasted rate, the projects are still expected to create benefits for our customers.

Our analysis leads us to conclude that the addition of this wind power to our system is prudent because it will deliver substantial financial benefits to our customers. These financial benefits are reflected in a lower cost of energy in the near- and long-term, and in a significant hedge against future increases in the fuel and government regulation components included in the cost of energy.

Thus, the Company is cost-effectively acquiring the resources necessary to meet the regulatory requirements of all the jurisdictions in which we provide service.

VII. CONCLUSION

For all of the reasons set forth above, we respectfully request the Commission make an advance determination of the prudence of the Company's addition of the Blazing Star I, Blazing Star II, Foxtail, Freeborn, Crowned Ridge, Lake Benton, and Clean Energy #1 wind generation projects to its system.

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Northern States Power Company

Respectfully submitted,

/s/ Aakash H. Chandarana

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