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BEFORE THE PUBLIC SERVICE COMMISSION OF THE STATE OF NORTH DAKOTA

NORTHERN STATES POWER COMPANY ADVANCE PRUDENCE – ACQUISITION OF 302.4 MW WIND GENERATION 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 (ADP) (Application) for the Company to build, own, and operate the Dakota Range I and II wind projects (collectively "Dakota Range" or "Project"). 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 Nos. PU-12-59 and PU-12-813, *et al.*

Dakota Range is a 302.4 MW self-build wind project located in South Dakota with an expected in-service date of 2021 and a projected Levelized Cost of Energy (LCOE) of **[TRADE SECRET BEGINS TRADE SECRET ENDS]**. This LCOE compares favorably to the wind projects recently filed with the Commission in Case No. PU-17-120, which had LCOEs in the range of **[TRADE SECRET BEGINS TRADE SECRET ENDS]**.

Dakota Range was considered but ultimately not included in the Company's recent Application for Advance Determination of Prudence for its 1,550 MW portfolio of wind generation to be added to the integrated NSP System in Case No. PU-17-120 (Wind Portfolio). We are bringing it forward for the Commission's approval now for several reasons. First, since the completion of the Wind Portfolio Request for Proposal (RFP) process, the price and transmission certainty of the Project have significantly improved. Second, Dakota Range may be one of the last projects available to us that will have this level of transmission certainty for quite some time. Third, even when using conservative assumptions, Dakota Range will provide benefits to our customers by driving down the overall system cost of fuel. For these reasons, the Dakota Range resource addition is prudent and should be granted an ADP.

By way of background, Apex Clean Energy (APEX) originally bid several versions of this project in response to our initial RFP conducted in late 2016 as part of our Wind Portfolio acquisition efforts. APEX offered the following six different options for the project: 1) a 700 MW Power Purchase Agreement (PPA) or Build-Own-Transfer (BOT) option for Dakota Range I-V; 2) a 300 MW PPA or BOT for Dakota Range I and II; and 3) a 300 MW PPA or BOT for Dakota Range III and IV. The Dakota Range III-IV BOT and the Dakota Range I-V BOT options were eliminated in the threshold review because APEX was not willing to take responsibility for the transmission costs, which was a threshold requirement. We ultimately did not pursue negotiations with APEX during the RFP process because the LCOEs for the Dakota Range I-II options were too high and the other options were not considered based on our evaluation of the price and non-price factors during the RFP.[1]

Since that time, however, MISO's August 2015 Definitive Planning Phase (DPP) Study Cycle has concluded and it assigned a reasonable amount of network upgrade costs to Dakota Range I and II, affording the Project substantially greater transmission certainty at lower than expected costs. This has the effect of not only lowering the total projected costs of the Project, but also increasing our overall confidence in Dakota Range's ability to reach commercial operation. Additionally, since the time of the RFP bid, the Company has conducted additional due diligence on other outstanding issues and confirmed the continued viability of the Project.

While we appreciate that we are bringing this project forward while the Commission is considering our 1,550 MW Wind Portfolio, we believe moving forward with Dakota Range will be beneficial to our customers. Most importantly, Dakota Range offers system cost savings to our customers over the life of the project. Like the 1,550 MW Wind Portfolio, production at this facility will displace more expensive fossil fuel generation or purchases in the MISO wholesale energy markets. We also conducted additional Strategist modeling runs to evaluate the addition of this 302.4 MW project in 2021. This analysis demonstrates that approximately $182 million in system-wide present value of revenue requirement (PVRR) savings will be realized over the twenty-five year life of Dakota Range compared to not adding the Project to the NSP System. This results in approximately $10 million in PVRR savings for our North Dakota customers over the same period.

[1] The LCOE for the Dakota Range I-II BOT option was **[TRADE SECRET BEGINS TRADE SECRET ENDS]** and PPA option was **[TRADE SECRET BEGINS TRADE SECRET ENDS]**.

The Dakota Range project represents a significant opportunity to drive down overall system costs and reduce North Dakota customers' energy expenses. For these reasons, Xcel Energy respectfully requests that the Commission grant an Advanced Determination of Prudence for the Dakota Range resource addition.

The remainder of this Application addresses the following:

- Description of the Applicant;
- Compliance Matters;
- The project selection process;
- An overview of the PTC;
- The Dakota Range project description, costs, and schedule;
- Explanation of the Project's supporting contracts;
- Economic analysis of the Project
- Prudence of the Dakota Range project; and
- Conclusion.

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

- Policy Testimony – Aakash Chandarana
- Project Selection and Resource Planning – Philip Joseph "P.J." Martin

II. 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."

This standard is similar to the "honestly and prudently invested" standard that the Commission uses for ratemaking.[2] The general prudence standard calls for determining whether the utility action was reasonable at the time it was taken under all

[2] *See* N.D.C.C. § 49-06-02.

relevant circumstances.[3] Under Section 49-05-16(1), the Commission may issue an order approving the prudence of a proposed project if four conditions are met:

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

D. Authority for Relief Requested

North Dakota Century Code § 49-05-16 allows for a public utility to seek an ADP from the Commission for a Resource Addition at the utility's discretion. Pursuant to the Settlement Agreement in Case No. PU-07-776, the Company is obligated to file an Application for an ADP for its acquisition of generating resources above 50 MW. Xcel Energy has committed to filing its ADP applications within fourteen days of seeking similar approvals in Minnesota.[4]

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, the contracts for the Dakota Range project are conditioned on the Commission granting an ADP, consistent with the Commission's precedent set in Case No. PU-12-59. Finally, we are making this Application within fourteen days of filing an application seeking approval for the Dakota Range project in Minnesota, which occurred on September 26, 2017.

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[3] *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).

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

III. DESCRIPTION AND PURPOSE OF THE PROJECT

In this section, we describe how we selected this project; the federal production tax credit (PTC) and its applicability to the Project; a description of the Projects, estimated costs, and schedule; the contracts necessary to execute our proposal; and the economic analysis supporting the proposed project.

A. PROJECT SELECTION

Dakota Range was bid into the September, 2015 RFP issued by the Company that, along with our Self Build proposals, culminated in the 1,550 MW Wind Portfolio for which we are seeking an ADP in Case No. PU-17-120.

As described in more detail in Case No. PU-17-120, the RFP bids were evaluated – with the oversight of an independent auditor – in a four step process: (1) completeness and threshold review to confirm that all information required had been included and that each proposal met the RFP criteria; (2) calculation of LCOE for each project; (3) non-price review, which scored the projects on areas such as permitting, site control, and transmission; and (4) final ranking. Upon completion of these steps, four projects totaling 1,100 MW materialized to the shortlist, with another two projects totaling 200 MW listed as backup. Our analysis and review was overseen and confirmed appropriate by the auditor.

In the RFP process, we assessed all projects on the basis of LCOE to group them into tranches of similarly priced projects. The highest LCOE eligible to be included in any of the three tranches considered was **[TRADE SECRET BEGINS TRADE SECRET ENDS]**. Several configurations for the Dakota Range project that were bid into the RFP qualified to be included in the initial scope of projects considered to move forward with negotiations. Two of the proposed options for Dakota Range were eliminated in the threshold stage because APEX was unwilling to commit to hold the Company harmless for any additional transmission costs. The remaining Dakota Range proposed configurations did not advance through to negotiations, however, due to non-price factors and their places in the final project rankings of the RFP bids.

APEX contacted the Company soon after the RFP process concluded to advise us it had additional information from MISO and now had greater certainty surrounding the Project's expected transmission costs. As a result, APEX offered to reduce its pricing. However, due to the RFP process rules as well as those agreed to with the independent auditor, we were unable to authorize a bid modification at that time. Since that time, and consistent with the Company's interest in continuing to identify advantageous resource additions on behalf of our customers, we have had periodic conversations with APEX and discovered that the primary issues that held the Project back from advancing in the RFP—price and transmission certainty—have been favorably resolved in light of APEX's resolution of transmission issues and the Company's ability to **[TRADE SECRET BEGINS**

TRADE SECRET ENDS]. Due to this, we believe moving forward with Dakota Range as a Company-build project at this time is reasonable and prudent.

B. PTC

Given the timing of moving forward with Dakota Range, we expect to be able to qualify for the phased down, 80 percent, PTC for the project. Even at this phased down level, the Project still results in cost savings to customers and is a prudent addition to the NSP System.

By way of background, projects that begin construction in 2018, such as Dakota Range, are eligible for 80 percent of the PTC amount due to the phased step down from 100 percent that began in 2017. Wind facilities must begin construction in 2018 to qualify for the 80 percent PTC "safe harbor." By law, 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 on equipment for the project or (2) incurring at least five percent of the total project cost.[5] 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.

In this case, the Company leveraged its pre-existing relationship with Vestas American Wind Technology, Inc. (Vestas) to assure PTC qualification in 2021 by securing its own safe-harbor turbines (the largest component of the project). This method of qualification was possible as a result of our relationship with Vestas, our experience in qualifying projects for the PTC, and our existing turbine agreement that was used to support our 1,550 MW Wind Portfolio.

During the course of our negotiations, we were also able to **[TRADE SECRET BEGINS**

[5] The Consolidated Appropriations Act, 2016.

TRADE SECRET ENDS].

As discussed below, we have developed a project schedule that optimizes pricing and keeps the project on track to ensure qualification of the maximum PTC at this time, 80 percent.

C. Project Description, Costs, and Schedule

1. Project Description

Dakota Range is being developed by APEX AGL, LLC, and is located on an approximately 40,000 acre site located 20 miles North of Watertown, South Dakota. The site is primarily rolling open fields used for grazing and farming.

We currently anticipate that the Project will consist of **[TRADE SECRET BEGINS TRADE SECRET ENDS]** wind turbines, resulting in 302.4 MW of nameplate wind power capacity. That said, should Vestas release new turbine technologies before construction that could result in higher annual energy production, we will have the ability to explore and possibly implement those technologies if we conclude that they will result in greater customer benefits. In addition to wind turbines, the Project will consist of an electrical collection system, access roads, substation and interconnection facilities, an operation and maintenance facility, and other infrastructure typical of a wind farm. We expect that APEX will apply for a wind farm siting permit from the South Dakota Public Utilities Commission some time before the end of 2017.

APEX applied to interconnect the Dakota Range project to the Otter Tail Power transmission system in March 2015 and was assigned project numbers J436 and J437 by MISO. This project will connect to the Otter Tail Power and Montana–Dakota Utilities 345 kV Big Stone – Ellendale transmission line at a new substation. The project was studied under the MISO August 2015 DPP Study Cycle. The MISO system impact and facility studies have been completed and all required transmission upgrades are known. These upgrades will be included in the Dakota Range Generator Interconnection Agreement (GIA) that is expected to be executed in the fourth quarter of 2017. The Company anticipates that the project will qualify as a capacity resource beginning in the 2023/2024 planning year.

The required transmission upgrades for the project include: (1) construction of a new 345 kV interconnection substation named Twin Brooks; (2) construction of a

+/- 200 MVar static compensator at the Stone Lake 345 kV substation; (3) upgrades to the Big Stone–Blair 230 kV transmission line; (4) upgrades to the Oaks-Foreman 230 kV transmission line and; (5) construction of capacitor banks at Electrafarm, Washburn, MidPort and Shaulis Road 161 kV substations. The MISO facility studies for the transmission upgrades were used to estimate the transmission upgrade costs required for the Dakota Range project. The final costs associated with the transmission upgrades will not be known until the facilities are placed into service and all accounting work has been completed.

We have estimated the transmission upgrades will cost **[TRADE SECRET BEGINS TRADE SECRET ENDS]** and interconnection costs will be **[TRADE SECRET BEGINS TRADE SECRET ENDS]**.

APEX is responsible for obtaining the necessary approvals to interconnect the Dakota Range project with the MISO transmission system. With respect to project curtailment, we expect that, over the lifetime of the project, curtailment will be consistent with the overall Company curtailment average of approximately four percent.

Figure 1: Dakota Range Wind Project Location

Our wind performance analysis predicts a net capacity factor (NCF) of **[TRADE SECRET BEGINS TRADE SECRET ENDS]** percent. We additionally project average Annual Energy Production (AEP) of approximately **[TRADE SECRET BEGINS TRADE SECRET ENDS]**, depending on final layout and turbine selection. This NCF **[TRADE SECRET BEGINS**

TRADE SECRET ENDS]. While APEX initially submitted an NCF with its RFP bid, we further worked with APEX and Vaisala (an independent wind consultant) to provide an energy production estimate for the updated turbine type.

2. *Project Costs*

Total capital costs for the Dakota Range Project are currently estimated at approximately **[TRADE SECRET BEGINS TRADE SECRET ENDS]** on a capital expenditure basis (i.e. excluding AFUDC and other customary adders), including the estimated transmission upgrades and interconnection costs discussed above and anticipated siting and permitting costs. The projected LCOE for the Dakota Range Project is **[TRADE SECRET BEGINS TRADE SECRET ENDS]**.

While APEX initially submitted a bid into our RFP with their costs and estimates, we compiled our own costs and estimates as the plans transitioned into a Company-built project. Our cost estimate of **[TRADE SECRET BEGINS TRADE SECRET ENDS]**. Our analysis was based on the Purchase and Sale Agreement (PSA) 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 – and most recently, the 1,550 MW wind portfolio acquisition docket and Public Service of Colorado's 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.

3. *Implementation Schedule*

We expect our primary construction activities on the Dakota Range Project will occur in 2020 and 2021. However, engineering and some procurement will occur in 2019. The current schedule indicates that wind turbine generators will be delivered to the project site starting in time to begin turbine erection in 2021. Under the current estimated schedule, we anticipate that commercial operation will be achieved by November 2021.

D. Supporting Contracts

1. Purchase and Sale Agreement (PSA)

Dakota Range will be Company built. Under this type of project arrangement, the Company will purchase the development assets of the Project such as permits, interconnection rights, contracts, easements, and other Project assets and then construct the Project itself. Xcel Energy will be purchasing the Project assets through a PSA with APEX.

We will continue with iterations of the due diligence review process until the closing date of the PSA for the project.[6] The continued due diligence process is necessary to ensure the contractual deliverables for the site development are received in a timely manner, and to further support our project development, engineering, construction and commissioning toward the planned in-service date.

2. Master Supply Agreement (MSA)

As discussed above, to meet the safe harbor requirements for this wind project, Xcel Energy's subsidiary, Capital Services, LLC is currently negotiating a fixed price MSA with Vestas for the provision of wind turbines to support our proposed Dakota Range wind project. Pursuant to the agreed-upon terms, Xcel Energy will secure sufficient turbine equipment to meet the five percent safe harbor requirement.

The MSA terms will be similar to those negotiated in the 2016 MSA with Vestas that supported the projects in our recent wind portfolio acquisition docket.

3. Balance of Plant (BOP)

As part of our development of this Company-build project, we will issue an RFP and enter into BOP construction contracts with third-party construction companies experienced in wind project construction. The BOP contracts will be fixed price, which will minimize schedule and cost risk.

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, electrical cable collection system, collection substations, and operations and maintenance building.

[6] The PSA is contingent on receiving an ADP from the Commission no later than September 30, 2018, among other things.

We note that in preparation for our cost estimates for the relevant scope of work for this project, we relied on the information gathered and bids received in our wind portfolio acquisition docket and also received indicative pricing from BOP contractors to support erection costs for various turbine types.

E. Economic Analysis

To evaluate the impact on our customers of the proposed wind portfolio, we used the Strategist resource planning model to conduct our analysis. The Strategist planning model simulates the operation of the NSP System and estimates the cost to serve load through the life of the project. We use the model to test results under a range of input assumptions. To assess their impact on customer costs, we simulated the operation of the NSP System through 2053 (the modelled time frame with a twenty five year life of project), with and without the addition of the 302.4 MW Dakota Range wind project proposed in this filing. All of our analysis assumes the addition of the 1,550 MWs of wind generation currently before the Commission in Docket No. PU-17-120.

Wind generation has no fuel costs so the marginal cost to produce the next unit of energy is zero. In other words, after capital and on-going O&M costs are accounted for, there are no costs for a wind generator to produce the next MWh of energy. As a result, MISO generally provides for wind production ahead of other, higher marginally-priced generation such as coal and natural gas-based generation. Consequently, as more wind generation is integrated into the system, coal and natural gas-fired thermal generation is dispatched less often. When the energy from the proposed project is produced, it displaces energy production from other Company resources or purchased energy from the MISO market. This displacement of other generation or market purchases largely drives the portfolio benefits shown in our modeling results.

We believe we have taken a conservative approach in developing the base assumptions as well as the sensitivities we used to analyze the proposed wind additions. We used the same assumptions regarding congestion that we used in the analysis of our last wind acquisition and did not change the methodology we used to model curtailment. Due to the addition of an incremental 302.4 MWs of wind, overall curtailment was impacted slightly, resulting in total curtailment of our wind additions of 4.2 percent compared to 3.8 percent shown in our previous analysis. We have updated other base assumptions consistent with the most recent modeling provided in our RTF filing, which provided updated impacts of the 1,550 MW wind addition.

1. Strategist Modeling

As noted above, we evaluated the proposed wind project assuming the addition of the 1,550 MWs of wind currently before the Commission for approval. Therefore, the results of the Strategist analysis provide the incremental savings due solely to the addition of the Dakota Range project. The results of the Strategist analysis shows that this new wind resource will result in net savings for our customers under all sensitivity tests conducted. Table 1, below, shows the PVRR savings.

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

	PVRR						
	Base	Markets Off	Low Gas Price	High Gas Price	+5% Cap Factor	-5% Cap Factor	Preferred Plan Renew
Reference Case	0	0	0	0	0	0	0
Dakota Range	(182)	(132)	(106)	(274)	(245)	(119)	(133)

As Table 1 indicates, the proposed wind project provides cost benefits to customers. In light of resource additions being added to the NSP System, there will be periods of time where the generation on our system exceeds our native load serving requirement. During these periods, we are likely to make energy sales into the MISO market. Revenues from those sales will be credited to customers through our Fuel Cost Rider (FCR). Thus, assumptions regarding the likely value of these potential sales are an important factor in predicting the likely rate impact of the proposed wind portfolio. Therefore, we have analyzed the PVRR under three different scenarios, "markets on," "preferred plan renewables," and "markets off" to assess how project revenues from the MISO market may be impacted under various conditions.

<u>Base Assumptions</u>
Under our base assumptions, we allow market sales and purchases. Once resources are added to the MISO system, they are typically dispatched based on the economic signals provided in the energy market. Thus, if it costs less to buy energy from the market as compared to running a system resource, market purchases are made. Purchasing energy from the market to reduce costs provides savings to our customers. To evaluate the likely impact on customer rates, we modeled market purchases and sales based on hourly forecasted LMPs at the Minnesota Hub. By matching hourly wind profiles with our forecast of hourly energy prices we are able to analyze the impact of the proposed wind additions. The impact of the market

interactions can be seen by comparing the base assumptions to the "markets off" sensitivity. Dakota Range is projected to provide customer cost savings of approximately $182 million PVRR ($10 million for North Dakota) using the base assumptions.

Markets Off Sensitivity
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. Because the markets-off sensitivity does not allow market purchases or sales, any generation in excess of system requirements is categorized as "dump energy." In this extreme sensitivity we did not give any value to the "dump energy." All benefits in this sensitivity come from savings attributable to our system resources. Even under this extreme case, the benefits of the additional wind project are significant at $132 million on a PVRR basis ($7 million for North Dakota), or approximately 73 percent of the base assumptions.

Preferred Plan Renewables Sensitivity
Our base assumptions do not include additional renewables beyond 2020. However, our preferred plan in our recent 2016-2030 Upper Midwest Resource Plan (IRP) included additions of solar and wind beyond what we proposed here. We note that, all else equal, additions of non-dispatchable resources will result in diminishing system benefits as future increments are added. Thus, we believe it is appropriate to analyze the impacts of the proposed portfolio without diminishing its value by assuming additions of renewable resources beyond what we are proposing here. However, to analyze the impact of the proposed additions in the context of our preferred plan, we ran a sensitivity that included an additional 1,650 MW of utility-scale solar resources between 2022 and 2030. While inclusion of these additional renewable resources reduces the benefit of Dakota Range by $49 million PVRR, the proposed Project continues to provide customer cost savings of $133 million PVRR ($7 million for North Dakota).

Additional Sensitivities
We performed four additional sensitivities to further test the cost effectiveness of the proposed resource addition.

- *Capacity Factor Sensitivities*

The capacity factor we included are based on an independent evaluation by Vaisala. Specifically, we worked with Vaisala to review and advise on the energy production that could be expected from the company-owned Vestas turbines.

We further tested our assumptions regarding capacity factors and the proposed project show significant cost savings to our customers under all sensitivities.

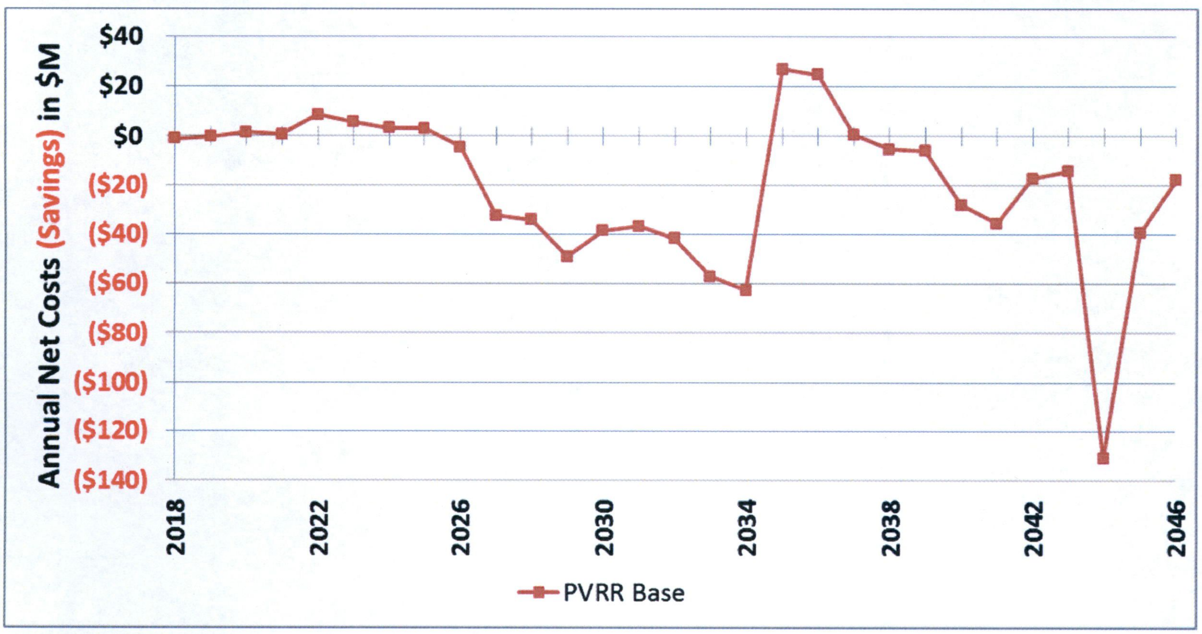
- *Natural Gas Price Forecast*

Our natural gas price forecast is based on a blend of the latest market information and long-term fundamentally-based forecasts acquired from third parties. We have included a low gas sensitivity to project the impacts of lower natural gas prices. The proposed wind resource is cost-effective under the low gas sensitivity.

2. *Annual Impacts*

To demonstrate how the costs (savings) change over time, Figure 2 below visually portrays the annual costs (savings) impacts of the total portfolio as compared to the Reference Case for the PVRR Base assumptions.

Figure 2: Annual Costs (Savings) Compared to Reference Case



Savings shown in Figure 2 for the PVRR Base assumptions assume we are able to take advantage of the MISO energy market to make energy purchases and sales. As the Company will take advantage of MISO energy market transactions when in the interest of our customers, we believe that modeling the availability of the MISO energy market provides a better indicator of the likely rate impacts to customers of the wind resource addition. As noted above, even in an extreme case where we are unable to take advantage of the MISO market or receive any revenue for "dump energy" the wind resources provide significant benefits to our customers. We have also included our most recently estimated wind integration and coal cycling costs. Based on those assumptions, we have included an impact of approximately $1 million per year due to the impact of coal cycling.

The addition of the proposed wind resource creates a net cost in 2021-2025 because the upfront capital expenses of the proposed project drive costs higher in the early years. But over the long term, customers receive significant rate benefits from avoided fuel and capacity costs and the accrual of PTCs. As shown in Figure 2, customers are expected to realize significant benefits beyond 2025. Due to a combination of the expiration of the PTC and the impact on deferred capacity, costs are expected to be higher than the base case from 2035 to 2037 before again providing savings through the end of the project's expected life.

In addition to the rate benefits of avoided fuel costs and the accrual of PTCs, deferred capacity additions provide savings to customers. The proposed wind resource defers a combustion turbine addition in 2027, 2029, 2040, and 2041 as compared to the Reference Case. It also defers a combined cycle unit from 2032 until 2035 and again in 2044 until 2045.

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 from fossil fuel resources, but the model also tracks benefits from additional capacity being added to the NSP System. The below table illustrates how the levelized costs of the proposed Project are more than offset by the value of avoided generation costs.

Table 2: PVRR Levelized Costs Analysis - $/MWh

	Dakota Range
LCOE	**[TRADE SECRET BEGINS** **TRADE SECRET ENDS]**
Wind Integration	$0.57
Wind Congestion	$3.39
Wind Induced Coal Cycling	$1.44
Avoided Production and Capacity Costs	($40.83)
Avoided Emission Costs	$0.00
	[TRADE SECRET BEGINS
Net Cost/(Benefit)	
	TRADE SECRET ENDS]

1. *Estimated Customer Rate Impacts*

We expect that soon after initial operation, customers' overall bills will be lower as a result of the acquisition of the proposed resource. Based on the results of our Strategist modeling, we expect that beginning in 2026 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. Specifically, we used the outputs from the rate-impact, markets-on scenario. We believe this scenario most closely reflects the impacts to customer bills. We note that the Strategist model relies on 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 3, below, shows the forecasted incremental impact on average monthly bills in North Dakota from 2017 to 2027.

Table 3: Forecasted Incremental Impact on Average Monthly Bills

Year	Residential	Commercial Non Demand	C&I Demand	Lighting
2017	$0.00	$0.00	$0.02	$0.00
2018	($0.02)	($0.03)	($0.73)	($0.02)
2019	($0.01)	($0.01)	($0.25)	($0.01)
2020	$0.03	$0.04	$0.95	$0.02
2021	$0.01	$0.02	$0.43	$0.01
2022	$0.16	$0.24	$5.62	$1.21
2023	$0.07	$0.11	$2.53	$0.51
2024	$0.06	$0.09	$2.10	$0.35
2025	$0.06	$0.09	$2.03	$0.33
2026	($0.09)	($0.12)	($2.85)	($0.79)
2027	($0.57)	($0.89)	($20.38)	($3.48)

IV. PRUDENCE OF THE PROPOSED TRANSACTIONS

The Company's proposed Dakota Range Project is prudent. Our analysis, with its conservative assumptions, shows that Dakota Range will result in significant cost savings to customers. We anticipate that North Dakota customers will save, conservatively, approximately $10 million over the life of the Dakota Range facility. Based on our analyses, we believe that it is prudent, reasonable and in our customers' best interests for the Commission to grant an ADP for this Project.

V. CONCLUSION

For all of the reasons set forth above, NSP respectfully requests the Commission make an advance determination of the prudence of the 302.4 MW Dakota Range wind project.

Dated: October 10, 2017

Northern States Power Company

Respectfully submitted,

David H Sederquist

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