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DIRECT TESTIMONY AND SCHEDULE
PHILIP JOSEPH "P.J." MARTIN

STATE OF NORTH DAKOTA
BEFORE THE
NORTH DAKOTA PUBLIC SERVICE COMMISSION

NORTHERN STATES POWER COMPANY
ADVANCE PRUDENCE – ACQUISITION OF 302.4 MW
WIND GENERATION APPLICATION

CASE NO. PU-17-____

Resource Planning Testimony

Exhibit___ (PJM-1)

October 10, 2017

3 PU-17-372 Filed: 10/10/2017 Pages: 51
Prefiled Direct Testimony of Philip Joseph P.J. Martin - redacted
Northern States Power Company
David Sederquist

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I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND TITLE.

A. My name is Philip Joseph "P.J." Martin. I am the Director, Resource Planning, for Northern States Power Company-Minnesota (NSP or Xcel Energy or the Company).

Q. PLEASE DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have worked for Xcel Energy since August of 2015 in the areas of Strategic Asset Planning and Resource Planning. In my first role at Xcel Energy in the Strategic Asset Planning group, I focused primarily on business planning for the four operating companies at Xcel Energy. I assumed my current role as Director, Resource Planning in October of 2016.

Prior to joining Xcel Energy, I worked as a Portfolio Director and Energy Trader at ACES Power Marketing. In these roles, I engaged in trading and wholesale portfolio management activities on behalf of electric cooperatives, municipal utilities, IPPs, banks, and other customers. I also supported long-term planning and risk management efforts for these customers in the Midcontinent Independent System Operator, Inc. (MISO), PJM Interconnection, LLC (PJM), SERC, and other markets across the U.S.

Q. WHAT ARE YOUR CURRENT RESPONSIBILITIES?

A. In my current role, I am responsible for the direction of electric resource planning for the five-state integrated Northern States Power Company system (NSP System), which provides electric service to customers in North

Dakota, South Dakota, Minnesota, Wisconsin, and Michigan. This includes assisting the Company in making reasonable and prudent acquisition decisions for electric generation resources. Among other things, I oversee our resource planning efforts using Strategist to conduct economic evaluations of potential resource additions, and oversee bid processes for new resource acquisitions.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to discuss the 302.4 MW Dakota Range I and II wind project (collectively "Dakota Range" or "Project") that we propose to be added to the integrated NSP System. My testimony details the Project and supports the conclusion that the North Dakota Public Service Commission (Commission) should grant an advance determination of prudence (ADP) for Dakota Range.

Q. HOW IS YOUR TESTIMONY STRUCTURED?

A. My testimony covers the following topics:

1. Project selection process;
2. Production Tax Credits (PTC);
3. Project description, costs, and schedule;
4. Project structure; and
5. Economic analysis of the Project.

II. PROJECT SELECTION PROCESS

Q. PLEASE BRIEFLY DESCRIBE THE PROPOSED DAKOTA RANGE PROJECT.

A. Dakota Range is a 302.4 MW self-build wind project located in Codington County, South Dakota with an expected in-service date of 2021.

Q. HOW DID THE COMPANY IDENTIFY THIS PROJECT?

A. Apex Clean Energy (APEX) submitted multiple Dakota Range proposals in response to the Company's Request for Proposal (RFP) for its recent Application for ADP for a 1,550 MW portfolio of wind generation to be added to the integrated NSP System (Wind Portfolio) in Case No. PU-17-120. Although none of the APEX proposals were selected for the Wind Portfolio, the parties continued discussions after the RFP in an attempt to identify a project that would provide value to customers.

Q. WHAT DAKOTA RANGE BIDS WERE SUBMITTED BY APEX FOR THE WIND PORTFOLIO RFP?

A. 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. Notably, none of APEX's bids included the sale of the selected site so the Company could develop the Project as such bids were not permitted under the RFP rules.

Q. PLEASE DESCRIBE THE PROCESS USED TO EVALUATE THE RFP BIDS AND COME TO THIS CONCLUSION.

A. With the oversight of an independent auditor, the APEX proposals, along with all of the other bids, were evaluated 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 Levelized Cost of Energy (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.

All projects were assessed on the basis of LCOE in order to group them into tranches of similarly priced projects. The highest LCOE eligible to be included in any of the three tranches was **[TRADE SECRET BEGINS TRADE SECRET ENDS]**. Several Dakota Range project proposals qualified to be included in the initial scope of projects considered to move forward with negotiations. Dakota Range did not advance through to negotiations, however, due to non-price factors and its place in the final project rankings of the RFP bids.

The Company began negotiations with project developers for projects totaling 1,100 MW (excluding Dakota Range), but due to the withdrawal of two developers and a tight timeframe for PTC qualification, the RFP process resulted in 800 MW of projects from the RFP. These projects, along with our self-build projects, comprised our total 1,550 MW Wind Portfolio.

Q. WHY WERE THE APEX BIDS NOT PURSUED DURING THE RFP?

A. 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. 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]**.

Q. IS THE CURRENT DAKOTA RANGE PROJECT PROPOSED ON THE SAME TERMS AS ONE OF THE BIDS INCLUDED IN THE WIND PORTFOLIO RFP?

A. No. The new proposal is structured as a self-build project, which arose from discussions between the Company and APEX after the close of the RFP process. The newly proposed project has both a lower cost and improved transmission certainty—which were the main issues preventing Dakota Range from being selected during the RFP—such that it would provide significant cost benefits to our customers.

Q. GENERALLY, HOW DID THE APEX BID CHANGE FROM THE ORIGINAL BIDS SUBMITTED IN RESPONSE TO THE RFP?

A. 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. Due to the RFP process rules as well as those agreed to with the independent auditor, however, the Company could not allow a bid modification at that time.

Q. WHAT HAPPENED AFTER THE COMPANY INFORMED APEX THAT IT WOULD NOT BE ABLE TO MODIFY ITS RFP BID?

A. Although APEX could not be included in the Wind Portfolio project due to the bidding rules, the Company continued to engage in periodic conversations with APEX to determine if an independent wind project would be viable and in the best interest of the Company's customers. The Company learned that one of the primary issues that held the Project back from advancing in the RFP—price—had been favorably resolved in light of APEX's resolution of transmission issues and could be further improved by the Company's ability to **[TRADE SECRET BEGINS TRADE SECRET ENDS]**. I discuss the price changes in more detail later in my testimony.

Q. WERE THERE REASONS OTHER THAN A REDUCTION IN PRICE THAT LED THE COMPANY TO PURSUE AN INDEPENDENT PROJECT WITH DAKOTA RANGE IN ADDITION TO THE WIND PORTFOLIO?

A. Yes. The improved certainty of transmission costs through the completion of the MISO Definitive Planning Phase (DPP) studies made moving forward with the project more attractive since it would provide additional comfort regarding pricing by mitigating the most variable risk of wind development. Also, 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.

III. PTC

Q. PLEASE DESCRIBE THE PTC ELIGIBILITY FOR DAKOTA RANGE.

A. Projects that begin construction in 2018, such as Dakota Range, are eligible for 80 percent of the Federal 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." Under the Consolidated Appropriations Act of 2016, 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. 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.

Q. WHAT STEPS WILL THE COMPANY TAKE TO QUALIFY FOR THE 80 PERCENT PTC?

A. 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. As I explain 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.

IV. PROJECT DESCRIPTION, COSTS, AND SCHEDULE

Q. PLEASE DESCRIBE THE LOCATION OF THE DAKOTA RANGE PROJECT.

A. 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.

Figure 1: Dakota Range Wind Project Location

Q. PLEASE DESCRIBE THE CAPACITY AND ANTICIPATED PERFORMANCE OF THE DAKOTA RANGE PROJECT.

A. 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.

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.

Q. DOES THE PROJECT INCLUDE FACILITIES OR INFRASTRUCTURE OTHER THAN THE TURBINES?

A. 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.

Q. WHAT ARE THE ESTIMATED CAPITAL COSTS OF THE PROJECT?

A. 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 as well as anticipated siting and permitting costs.

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.

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

TRADE SECRET ENDS].

Q. WHAT IS THE PROJECTED LCOE FOR THE PROJECT?

A. The projected LCOE for the Dakota Range Project is **[TRADE SECRET BEGINS TRADE SECRET ENDS]** which is based on several assumptions.

Q. WHAT IS THE CONSTRUCTION SCHEDULE FOR THE PROJECT?

A. 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.

Q. WHAT IS THE STATUS OF THE SOUTH DAKOTA SITING PERMITS?

A. We expect APEX to apply for siting permits from the South Dakota Public

Utilities Commission some time before the end of 2017.

Q. PLEASE DESCRIBE HOW AND WHEN DAKOTA RANGE WILL INTERCONNECT TO THE TRANSMISSION GRID.

A. APEX is responsible for obtaining the necessary approvals to interconnect the Dakota Range project with the MISO transmission system. 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.

Q. WHAT ARE THE EXPECTED TRANSMISSION NETWORK UPGRADE AND INTERCONNECTION COSTS OF DAKOTA RANGE?

A. 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 STATCOM 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]**, both on a capital expenditure basis (i.e. excluding AFUDC and other customary adders).

Q. WHAT ARE THE COMPANY'S WIND CURTAILMENT ESTIMATES FOR THE PROJECT?

A. 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.

V. PROJECT STRUCTURE

Q. HOW IS THE SELF-BUILD DAKOTA RANGE PROJECT STRUCTURED?

A. The transaction is structured to allow the Company to step into the shoes of APEX and complete development of the Dakota Range Project. To accomplish this, our work is structured around three key contracts.

- The first is the PSA for the purchase of the Project, including the real estate rights, permits, and contracts necessary for completion of the Project.
- The second is the Master Supply Agreement (MSA) that is being negotiated with Vestas American Wind Technology, Inc. for the purchase of the wind turbine generators for the Project.
- The third is the BOP contract that will be negotiated and executed with a contractor for the construction of the components of the Project.

Q. WHAT ARE THE DETAILS OF THE PSA?

A. Dakota Range will be a self-build project. 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.

The PSA is contingent on several conditions precedent, including:

- Receiving an ADP from the Commission no later than September 30, 2018, which may be extended by APEX under certain circumstances to no later than March 31, 2019;
- Interconnection Rights have been obtained;
- Due diligence on real estate contracts, title, permitting, and closing reports.

We will continue with iterations of the due diligence review process until the closing date of the PSA for the project. 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.

Q. PLEASE BRIEFLY DESCRIBE THE DETAILS OF THE MSA.

A. 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. The Company and Vestas have so far reached agreement on the principle terms of this agreement. Pursuant to the agreed-upon terms, Xcel Energy will secure sufficient turbine equipment to meet the five percent safe harbor requirement. The final MSA terms will be similar to those negotiated in the 2016 MSA with Vestas that supported the projects in the Wind Portfolio.

Q. WHAT IS THE STATUS OF THE BOP AGREEMENTS?

A. 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.

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 the various turbine types.

VI. ECONOMIC ANALYSIS OF THE PROJECT

Q. HOW DID THE COMPANY EVALUATE THE COST-EFFECTIVENESS OF THE DAKOTA RANGE PROJECT?

A. We principally used the Strategist resource planning model (Strategist).

Q. WHAT IS STRATEGIST?

A. Strategist is a modeling program that simulates the operation of the NSP System and estimates the total cost of energy over the life of a project on a present value basis. Strategist can be used to test results under a range of input assumptions, also known as sensitivities. The Company uses this tool, which is industry standard, for the majority of its resource planning efforts.

Q. HOW DID THE COMPANY USE STRATEGIST TO ANALYZE THE DAKOTA RANGE WIND PROJECT?

A. We used Strategist to simulate 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 of wind generation proposed in the Dakota Range filing. All of our analysis assumes the addition of the

1,550 MWs of wind generation currently before the Commission in Case No. PU-17-120.

By reducing the amount of fossil fuel purchases and the amount of energy that is purchased from the market, thereby reducing the Company's overall fuel and purchased power costs, wind generation creates cost savings. Our Strategist analysis accounts for these cost savings, as well as the impact of the capital commitments associated with adding the wind generation project.

Q. IN GENERAL, WHAT IS THE SOURCE OF THE SAVINGS ASSOCIATED WITH THE PROJECT?

A. 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.

Q. HOW DID YOU DEVELOP THE ASSUMPTIONS AND SENSITIVITIES USED IN YOUR STRATEGIST ANALYSIS?

A. 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 the Wind Portfolio 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 Summer, 2017 RTF filing, Case Nos. PU-12-813, et. al. which provided updated impacts of the 1550 MW wind addition. Those updated assumptions include an updated load forecast and natural gas forecast and are provided in Exhibit __,(PJM-1), Schedule 1.

Q. WHAT WAS THE RESULT OF THE STRATEGIST ANALYSIS?

A. 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. The PVRR savings do not include CO_2 costs or other externality costs and do not include the surplus capacity credit.

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)

Q. WHAT DOES THIS TABLE SHOW?

A. It shows that the proposed wind project provides cost benefits to customers in all scenarios. 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.

Q. WHAT ASSUMPTIONS DID THE COMPANY MAKE IN DEVELOPING THIS ANALYSIS?

A. In general, we believe we took a conservative approach in assessing the economic impacts of the Wind Portfolio. As required by North Dakota law, no environmental externality costs are included in the analysis.

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.

Q. PLEASE DESCRIBE THE MARKETS-OFF SENSITIVITY.

A. In this sensitivity (the second column in the previous table), we utilized a Markets-Off view. 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.

Q. PLEASE DESCRIBE THE PREFERRED PLAN RENEWABLES SENSITIVITY.

A. 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).

Q. PLEASE DESCRIBE THE GAS PRICE SENSITIVITIES.

A. Our 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, and provides an even larger benefit under the high gas price sensitivity.

Q. PLEASE DESCRIBE THE CAPACITY SENSITIVITIES.

A. The capacity factors 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 shows significant cost savings to our customers under all capacity sensitivities.

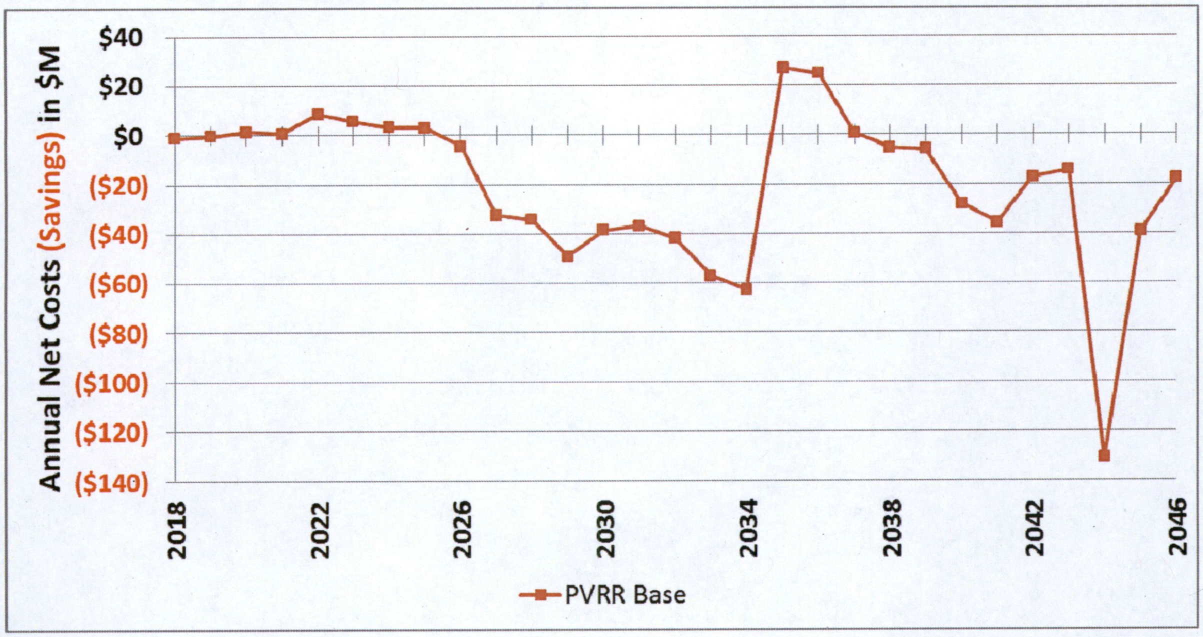
Q. WHAT DO YOU CONCLUDE FROM THIS ANALYSIS?

A. I conclude that the Wind Portfolio will provide material cost savings to the NSP System in all scenarios analyzed.

Q. DID THE COMPANY ANALYZE HOW THESE COST SAVINGS EVOLVE OVER THE LIFE OF THE PROJECT?

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

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



Q. WHAT ASSUMPTIONS DID THE COMPANY USE IN CREATING FIGURE 2?

A. 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 a cost of approximately $1 million per year due to the impact of coal cycling.

Q. WHAT DOES FIGURE 2 DEMONSTRATE?

A. 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.

Q. ARE THERE OTHER WAYS TO LOOK AT THESE SAVINGS?

A. Yes. An alternate way of assessing the value of the proposed wind project to the system is by evaluating the levelized price of the Project and the other costs and benefits associated with it. Levelized prices are a fixed $/MWh price that have the same net present value as the actual cost streams generated by Strategist.

Q. WHAT WERE THE RESULTS OF YOUR ANALYSIS OF THE LEVELIZED COSTS?

A. 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. Table 2 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]

Q. WHAT IS THE ESTIMATED IMPACT OF ADDING THE PROJECT ON THE RATES PAID BY THE COMPANY'S NORTH DAKOTA CUSTOMERS?

A. 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 put it another way, production from the Dakota Range Project will displace other generation on our System, or purchases in the MISO wholesale market, that would be at higher marginal costs.

Q. PLEASE EXPLAIN HOW YOU REACHED THAT CONCLUSION.

A. 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.

Q. HOW WILL THESE CHANGES IN REVENUE REQUIREMENTS BE REFLECTED ON NORTH DAKOTA CUSTOMERS' BILLS?

A. Table 3, below, shows the forecasted incremental impact on average monthly bills in North Dakota from 2017 to 2027. It is important to note that if the costs of these wind additions are recovered through a rider, the actual timing of the recovery and the rate design approved in a future rate case will impact the actual class allocation. We have provided an estimated impact below.

Table 3: Forecasted Incremental Impact on ND Customers' 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)

VII. CONCLUSION

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes, it does.

I. Strategist Modeling Assumptions

1. Discount Rate and Capital Structure

The discount rate used for levelized cost calculations and the present value of modeled costs is 6.30 percent. The rates shown in Table 1 were calculated by taking a weighted average of NSP jurisdictions from the June 2017 Corporate Assumptions Memo.

Table 1: Capital Structure

	Capital Structure	Allowed Return	Before Tax Electric WACC	After Tax Electric WACC
Long-Term Debt	45.60%	4.87%	2.22%	1.32%
Common Equity	52.50%	9.39%	4.93%	4.93%
Short-Term Debt	1.90%	2.85%	0.05%	0.05%
Total			**7.20%**	**6.30%**

2. Inflation Rates

The inflation rates are used for existing resources, generic resources, and other costs related to general inflationary trends in the modeling. The inflation rates are developed using long-term forecasts from Global Insight. The labor and non-labor inflation rates are from the February 2016 Corporate Assumptions Memo. The General inflation rate is from the "Chained Price Index for Total Personal Consumption Expenditures" published in the third quarter of 2015.

- Variable O&M inflation – 50% labor inflation and 50% non-labor inflation – 2.88%.
- Fixed O&M inflation – 75% labor inflation and 25% non-labor inflation – 3.07%.
- General inflation – The inflation rate used for construction (capital) costs and any other escalation factor related to general inflationary trends is 2.0%.

3. Reserve Margin

The reserve margin at the time of MISO's peak is 7.8 percent. The coincidence factor between the NSP System and MISO system peak is 5 percent. Therefore, the effective reserve margin is:

$$(1 - 5\%) * (1 + 7.8\%) - 1 = 2.41\%.$$

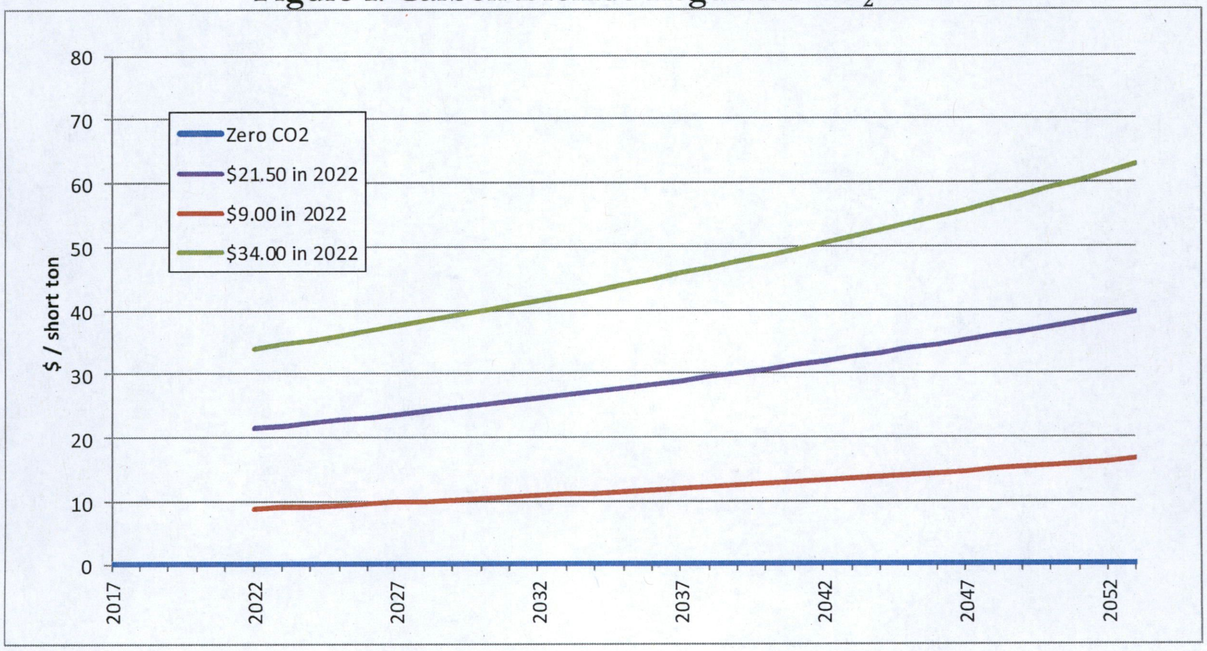
Table 2: Reserve Margin

Reserve Margin	
Coincidence Factor	5.00%
MISO Coincident Peak Reserve Margin %	7.80%
Effective RM Based on Non-coincident Peak	2.41%

4. Regulated CO_2 Costs

Figure 1 shows the annual Regulated CO_2 Costs used in the analysis. The base assumption is $21.50 per short ton starting in 2022 which is the average of $9 per short ton and $34 per short ton. The range of Regulated CO_2 Costs is drawn from the Minnesota Public Utilities Commission's Order Establishing 2016 and 2017 Estimate of Future Carbon Dioxide Regulation Costs in Docket No. E999/CI-07-1199 issued August 5, 2016. All prices escalate at general inflation.

Figure 1: Carbon Dioxide Regulated CO_2 Cost



5. Externality Costs

Externality Costs for NOx, PM10, CO, and Pb are based on the high values from the Minnesota Public Utilities Commission's Notice of Comment Period on Updated Environmental Externality Values issued June 16, 2016 (Docket Nos. E999/CI-93-583 and E999/CI-00-1636) and are shown in Table 3 below. Prices are shown in 2016 dollars and escalate at general inflation. Sulfur dioxide assumed zero cost due to a large surplus of allowances, a weak sales market, and zero externality cost per Commission policy.

Table 3: Externality Costs

MPUC Externality Costs $2016 per short ton				
	Urban	Metro Fringe	Rural	<200mi
NOx	$1,466	$399	$153	$153
PM10	$9,627	$4,326	$1,282	$1,282
CO	$3	$2	$1	$1
Pb	$5,808	$2,990	$671	$671

Externality Costs for CO_2 are based on the low and high values from MPUC Docket No. E999-CI-14-643, Fourth Affidavit of Anne E. Smith, Ph.D., Table B. These values in nominal dollars are shown in Table 4.

Table 4: Carbon Dioxide Externality Costs

MPUC CO_2 Externality Costs		
$ per short ton		
Year	Low	High
2017	8.78	41.37
2018	9.17	43.15
2019	9.58	44.99
2020	9.99	46.88
2021	10.42	48.83
2022	10.87	50.84
2023	11.32	52.91
2024	11.80	55.05
2025	12.28	57.24
2026	12.78	59.51
2027	13.29	61.85
2028	13.83	64.25
2029	14.37	66.73
2030	14.94	69.27
2031	15.51	71.89
2032	16.12	74.59
2033	16.72	77.37
2034	17.37	80.23
2035	18.01	83.17
2036	18.69	86.20
2037	19.37	89.31
2038	20.09	92.52
2039	20.81	95.83
2040	21.57	99.22
2041	22.34	102.71
2042	23.15	106.30
2043	23.96	110.00
2044	24.81	113.80
2045	25.67	117.70
2046	26.57	121.72
2047	27.48	125.85
2048	28.43	130.10
2049	29.39	134.46
2050	30.40	138.95
2051	31.42	143.58
2052	32.47	148.32
2053	33.56	153.20

6. Demand and Energy Forecast

The Spring 2017 Load Forecast developed by the Xcel Energy Load Forecasting group is used.

Table 5: Spring 2017 Demand and Energy Forecast

Demand (MW)					Energy (GWh)			
Year	Model Output	W/ Hist DSM, Building Code Adj	Final w DSM/Eff Adjustments		Year	Model Output	W/ Hist DSM, Building Code	Final w DSM/Eff Adjustments
2017	10,435	9,293	9,202		2017	50,828	44,965	44,526
2018	10,485	9,401	9,221		2018	50,739	45,279	44,400
2019	10,559	9,535	9,263		2019	51,173	45,957	44,639
2020	10,646	9,652	9,309		2020	51,485	46,477	44,705
2021	10,726	9,773	9,358		2021	51,715	46,904	44,688
2022	10,815	9,931	9,444		2022	51,912	47,391	44,726
2023	10,911	10,004	9,314		2023	52,217	47,861	44,747
2024	11,013	10,169	9,392		2024	52,566	48,387	44,813
2025	11,123	10,330	9,466		2025	52,831	48,988	44,976
2026	11,239	10,504	9,553		2026	52,984	49,493	45,032
2027	11,343	10,710	9,672		2027	53,258	50,214	45,304
2028	11,445	10,879	9,754		2028	53,630	51,036	45,662
2029	11,558	10,993	9,781		2029	53,930	51,447	45,639
2030	11,673	11,152	9,853		2030	54,118	51,923	45,666
2031	11,779	11,280	10,008		2031	54,414	52,356	46,090
2032	11,883	11,391	10,146		2032	54,778	52,788	46,493
2033	12,005	11,530	10,312		2033	55,080	53,191	46,905
2034	12,127	11,653	10,435		2034	55,263	53,416	47,130
2035	12,234	11,751	10,534		2035	55,551	53,715	47,429
2036	12,335	11,858	10,640		2036	55,903	54,151	47,846
2037	12,450	11,949	10,732		2037	56,184	54,393	48,106
2038	12,570	12,045	10,828		2038	56,363	54,530	48,244
2039	12,679	12,129	10,911		2039	56,675	54,798	48,512
2040	12,784	12,206	10,989		2040	57,059	55,135	48,830
2041	12,900	12,293	11,075		2041	57,371	55,399	49,113
2042	13,020	12,381	11,164		2042	57,560	55,537	49,251
2043	13,124	12,451	11,234		2043	57,877	55,800	49,514
2044	13,237	12,530	11,313		2044	58,241	56,112	49,807
2045	13,326	12,586	11,368		2045	58,563	56,384	50,098
2046	13,438	12,664	11,447		2046	58,748	56,521	50,235
2047	13,540	12,733	11,515		2047	59,117	56,836	50,550
2048	13,644	12,803	11,585		2048	59,590	57,254	50,950
2049	13,748	12,873	11,655		2049	59,729	57,347	51,061
2050	13,851	12,943	11,726		2050	60,036	57,602	51,316
2051	13,955	13,013	11,796		2051	60,342	57,857	51,567
2052	14,059	13,083	11,866		2052	60,818	58,278	51,969
2053	14,163	13,153	11,936		2053	60,955	58,368	52,078

7. DSM Forecast

The DSM forecast assumes impacts expected at a 75 percent rebate level which equals roughly 1.5 percent of sales through the planning period.

Table 6: DSM Forecast

Year	Energy (MWh)	Demand (MW)
2017	439	113
2018	879	227
2019	1,318	342
2020	1,772	429
2021	2,216	516
2022	2,665	603
2023	3,114	690
2024	3,573	777
2025	4,012	864
2026	4,461	951
2027	4,910	1,038
2028	5,375	1,125
2029	5,808	1,212
2030	6,257	1,299
2031	6,266	1,272
2032	6,294	1,245
2033	6,286	1,217
2034	6,286	1,217
2035	6,286	1,217
2036	6,305	1,217
2037	6,286	1,217
2038	6,286	1,217
2039	6,286	1,217
2040	6,305	1,217
2041	6,286	1,217
2042	6,286	1,217
2043	6,286	1,217
2044	6,305	1,217
2045	6,286	1,217
2046	6,286	1,217
2047	6,286	1,217
2048	6,305	1,217
2049	6,286	1,217
2050	6,286	1,217
2051	6,290	1,217
2052	6,308	1,217
2053	6,290	1,217

8. Demand Response Forecast

The 2017 Load Management Forecast developed by the Xcel Energy Load Research group is used. The table below shows the July demand.

Table 7: 2017 Load Management Forecast

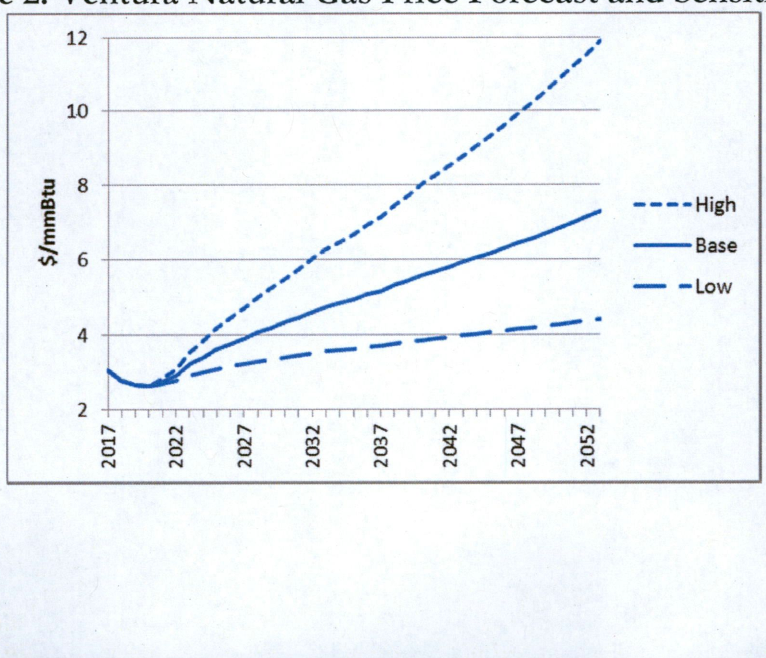
July Demand (MW)	2017	2018	2019	2020	2021	2022	2023	2024
LMF	853	864	880	896	911	926	933	940
July Demand (MW)	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
LMF	947	948	944	940	936	932	928	924
July Demand (MW)	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
LMF	920	916	913	909	905	901	898	894
July Demand (MW)	**2041**	**2042**	**2043**	**2044**	**2045**	**2046**	**2047**	**2048**
LMF	891	887	884	880	877	873	870	866
July Demand (MW)	**2049**	**2050**	**2051**	**2052**	**2053**			
LMF	863	860	856	853	849			

9. Natural Gas Price Forecasts

Henry Hub natural gas prices are developed using a blend of market information (New York Mercantile Exchange futures prices) and long-term fundamentally-based forecasts from Wood Mackenzie, Cambridge Energy Research Associates (CERA) and Petroleum Industry Research Associates (PIRA).

Gas Prices as of February 28, 2017 were used. High and low gas price sensitivities were performed by adjusting the growth rate up and down by 50 percent from the base natural gas cost forecast starting in year 2021.

Figure 2: Ventura Natural Gas Price Forecast and Sensitivities



10. Natural Gas Transportation Costs

Gas transportation variable costs include the gas transportation charges and the Fuel Lost & Unaccounted (FL&U) for all of the pipelines the gas flows through from the Ventura Hub to the generators facility. The FL&U charge is stated as a percentage of the gas expected to be consumed by the plant, effectively increasing the gas used to operate the plant, and is at the price of gas commodity being delivered to the plant. Table 12 contains gas transportation charges for generic thermal resources.

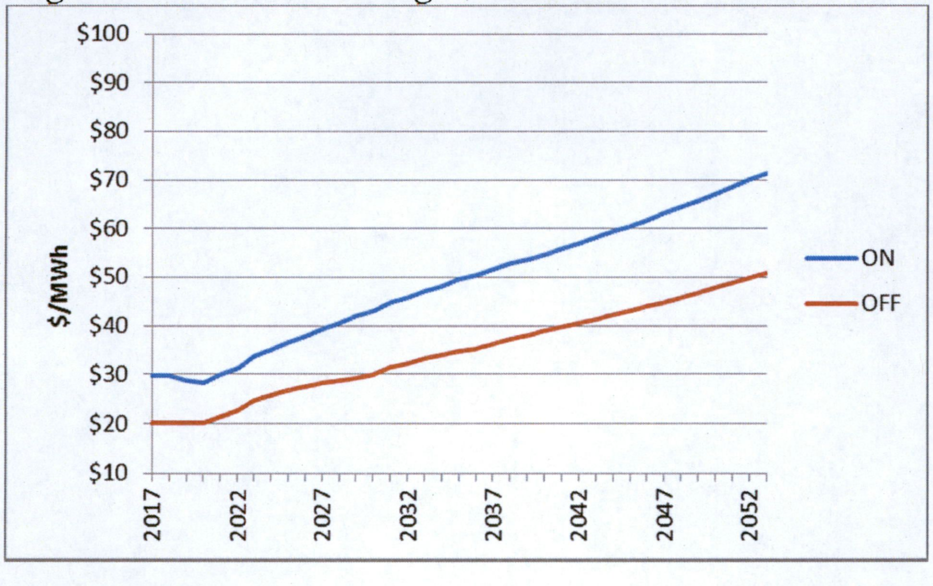
11. Natural Gas Demand Charges

Gas demand charges are fixed annual payments applied to resources to guarantee that natural gas will be available (normally called "firm gas"). Typically, firm gas is obtained to meet the needs of the winter peak as enough gas is normally available during the summer. Table 12 contains gas demand charges for generic thermal resources.

12. Electric Power Market Prices

In addition to resources that exist within the NSP System, the Company is a participant in the MISO Market. Electric power market power prices are developed from fundamentally-based forecasts from Wood Mackenzie, CERA and PIRA. Figure 3 below shows the market prices under zero cost CO_2 assumptions.

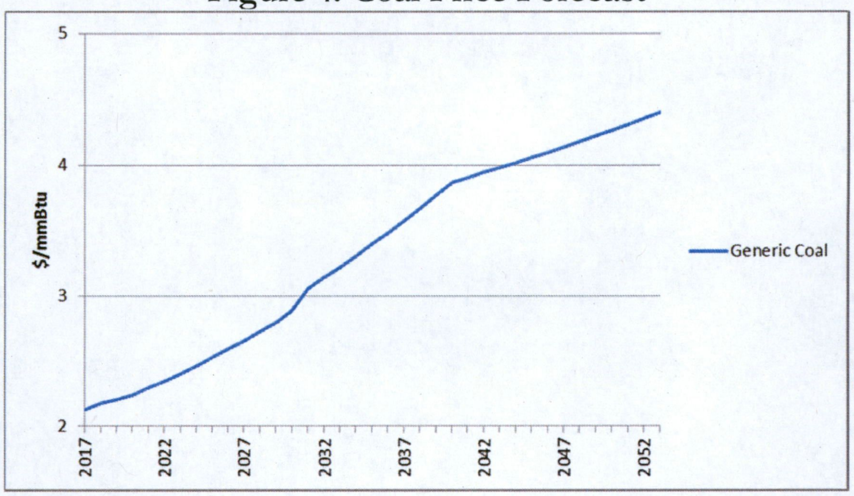
Figure 3: Minn Hub Average On and Off Peak Market Price



13. Coal Price Forecast

Coal price forecasts are developed using two major inputs: the current contract volumes and prices combined with current estimates of required spot volumes and prices. Typically coal volumes and prices are under contract on a plant by plant basis for a one to five year term with annual spot volumes filling the estimated fuel requirements of the coal plant based on recent unit dispatch. The spot coal price forecasts are developed from price forecasts provided by Wood Mackenzie, JD Energy, and John T Boyd Company, as well as price points from recent Request for Proposal (RFP) responses for coal supply. Layered on top of the coal prices are transportation charges, SO_2 costs, freeze control and dust suppressant, as required.

Figure 4: Coal Price Forecast



14. Surplus Capacity Credit

The credit is applied for all twelve months of each year and is priced at the avoided capacity cost of a generic combustion turbine.

Table 8: Surplus Capacity Credit

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
$/kW-mo	4.84	4.94	5.03	5.14	5.24	5.34	5.45	5.56	5.67	5.78

	2027	2028	2029	2030	2031	2032	2033	2034	2035
$/kW-mo	5.90	6.02	6.14	6.26	6.39	6.51	6.64	6.78	6.91

	2036	2037	2038	2039	2040	2041	2042	2043	2044
$/kW-mo	7.05	7.19	7.33	7.48	7.63	7.78	7.94	8.10	8.26

	2045	2046	2047	2048	2049	2050	2051	2052	2053
$/kW-mo	8.43	8.59	8.77	8.94	9.12	9.30	9.49	9.68	9.87

15. Transmission Delivery Costs

Generic 2x1 combined cycle (CC), generic combustion turbine (CT), generic wind and generic solar have assumed transmission delivery costs. The table below shows the transmission delivery costs on a $/kW basis. The CC and CT costs were developed based on the average of several potential sites in the Minnesota. The general site locations were investigated by Transmission Access for impacts to the transmission grid and expected resulting upgrade costs

Table 9: Transmission Delivery Costs

	$/kw	
CC	$	429
CT	$	158
Solar	$	70
Wind	$	96

16. Interconnection Costs

Estimates of interconnection costs of the generic resources were included in the capital cost estimates.

17. Effective Load Carrying Capability (ELCC) Capacity Credit for Wind Resources

Existing wind units is based on current MISO accreditation. New wind additions are given a capacity credit equal to 15.6 percent of their nameplate rating per MISO 2017/2018 Wind Capacity Report.

18. ELCC Capacity Credit for Utility Scale Solar Photovoltaic (PV) Resources

Utility scale generic solar PV additions used in modeling the alternative plans were given a capacity credit equal to 50 percent of the AC nameplate capacity. This value is the MISO proposed solar capacity credit for the 2016/2017 planning year.

19. Spinning Reserve Requirement

Spinning Reserve is the on-line reserve capacity that is synchronized to the grid to maintain system frequency stability during contingency events and unforeseen load swings. The level of spinning reserve modeled is 94 MW and is based on a 12 month rolling average of spinning reserves carried by the NSP System within MISO.

20. Emergency Energy Costs

Emergency Energy Costs were assigned in the Strategist model if there were not enough resources available to meet energy requirements. The cost was set at $500/MWh in 2014 escalating at inflation which is about $150/MWh more than an oil unit with an assumed heat rate of 15 mmBtu/MWh. Emergency energy occurs only in rare instances.

21. Wind Integration Costs

Wind integration costs were priced based upon the results of the NSP System Wind Integration Cost Study. Wind integration costs contain five components:

1. MISO Contingency Reserves
2. MISO Regulating Reserves
3. MISO Revenue Sufficiency Guarantee Charges
4. Coal Cycling Costs
5. Gas Storage Costs

The complete Wind Integration Study is included in Appendix M of the 2015 Upper Midwest Resource Plan. The results of the study as used in Strategist are shown below. The Coal Cycling Costs are zero after 2040 because the last coal unit on the Company's system in the modeling retires in 2040.

Table 10: Wind Integration Costs

	Wind Integration $/MWh		Coal Cycling $/MWh	
	Existing Resources	New Resources	Existing Resources	New Resources
2016	0.41	0.42	0.75	1.26
2017	0.42	0.43	0.77	1.28
2018	0.43	0.44	0.78	1.31
2019	0.44	0.45	0.80	1.33
2020	0.44	0.46	0.82	1.36
2021	0.45	0.46	0.83	1.39
2022	0.46	0.47	0.85	1.41
2023	0.47	0.48	0.87	1.44
2024	0.48	0.49	0.88	1.47
2025	0.49	0.50	0.90	1.50
2026	0.50	0.51	0.92	1.53
2027	0.51	0.52	0.94	1.56
2028	0.52	0.53	0.96	1.59
2029	0.53	0.54	0.98	1.62
2030	0.54	0.55	1.00	1.66
2031	0.55	0.56	1.01	1.69
2032	0.56	0.58	1.04	1.72
2033	0.58	0.59	1.06	1.76
2034	0.59	0.60	1.08	1.79
2035	0.60	0.61	1.10	1.83
2036	0.61	0.62	1.12	1.87
2037	0.62	0.63	1.14	1.90
2038	0.64	0.65	1.17	1.94
2039	0.65	0.66	1.19	1.98
2040	0.66	0.67	1.21	2.02
2041	0.67	0.69	-	-
2042	0.69	0.70	-	-
2043	0.70	0.71	-	-
2044	0.72	0.73	-	-
2045	0.73	0.74	-	-
2046	0.74	0.76	-	-
2047	0.76	0.77	-	-
2048	0.77	0.79	-	-
2049	0.79	0.80	-	-
2050	0.81	0.82	-	-
2051	0.82	0.83	-	-
2052	0.84	0.85	-	-
2053	0.86	0.87	-	-

22. Wind Congestion Costs

Wind Congestion Costs were developed by Xcel Energy Transmission Planning group from PROMOD LMP simulations for years 2020 and 2025 using the MTEP 16 database. Based on those simulations, we included congestion cost of $2.71 per MWh in 2020, escalating at 2% thereafter, for all new wind including the 300MW Dakota Range project.

Table 11: Wind Congestion Costs

	Wind Congestion $/MWh	
	Existing Resources	New Resources
2017	-	-
2018	-	-
2019	-	2.66
2020	-	2.71
2021	-	2.77
2022	-	2.82
2023	-	2.88
2024	-	2.93
2025	-	2.99
2026	-	3.05
2027	-	3.11
2028	-	3.18
2029	-	3.24
2030	-	3.31
2031	-	3.37
2032	-	3.44
2033	-	3.51
2034	-	3.58
2035	-	3.65
2036	-	3.72
2037	-	3.80
2038	-	3.87
2039	-	3.95
2040	-	4.03
2041	-	4.11
2042	-	4.19
2043	-	4.28
2044	-	4.36
2045	-	4.45
2046	-	4.54
2047	-	4.63
2048	-	4.72
2049	-	4.81
2050	-	4.91
2051	-	5.01
2052	-	5.11
2053	-	5.21

23. Distributed Generation and Community Solar Gardens

The small solar inputs are based on the most recent Company forecast.

24. Assumption and Sensitivity Descriptions

The modeling uses the following assumptions and sensitivities. The Base Assumptions are combined with the Sensitivities to test the modeling results for critical variables.

Table 12: Assumption and Sensitivity Descriptions

Base Assumptions	Assumption Description
PVSC Base	All Strategist expansion plans are optimized under the PVSC Base assumption. PVSC Base includes the Regulated CO_2 Cost of $21.50 per short ton in 2022, Externality Costs, and Surplus Capacity Credit. Optimized expansion plans were completed using the PVSC Base assumption and the PVSC Base assumption combined with the following sensitivity: Preferred Plan Renewables. All Strategist outputs except the Markets Off sensitivity assume the modeling of MISO Energy Market interactions.
PVRR Base	This assumption removes Regulated CO_2 Costs, Externality Costs, and the Surplus Capacity Credit from the PVSC Base assumption. All Strategist outputs except the Markets Off sensitivity assume the modeling of MISO Energy Market interactions.
Sensitivities	**Sensitivity Description**
Markets Off	This sensitivity removes the modeling of the Company's hourly purchases and sales in the MISO Energy Market.
Low Gas Price	This sensitivity decreases the annual year-over-year percent change in natural gas prices by 50% starting in year 2021.
High Gas Price	This sensitivity increases the annual year-over-year percent change in natural gas prices by 50% starting in year 2021.
Low CO_2 Externality	This sensitivity removes the Regulated CO_2 Cost and models the Low Externality Price of CO_2 for the modeling period.
High CO_2 Externality	This sensitivity removes the Regulated CO_2 Cost and models the High Externality Price of CO_2 for the modeling period.
+5% Cap Factor	This sensitivity increases the expected capacity factor by 5% for the proposed Dakota Range project.
-5% Cap Factor	This sensitivity decreases the expected capacity factor by 5% for the proposed Dakota Range project.
Preferred Plan Renewables	This sensitivity adds 1650MW of additional utility-scale solar by 2030.

25. Owned Unit Modeled Operating Characteristics and Costs

Company owned units were modeled based upon their tested operating characteristics and historical or projected costs. Below is a list of typical operating and cost inputs for each company owned resource.

a. Retirement Date
b. Maximum Capacity
c. Current Unforced Capacity (UCAP) Ratings
d. Minimum Capacity Rating
e. Seasonal Deration
f. Heat Rate Profiles
g. Variable O&M
h. Fixed O&M

i. Maintenance Schedule
j. Forced Outage Rate
k. Emission rates for SO_2, NO_x, CO_2, Mercury and particulate matter (PM)
l. Contribution to spinning reserve
m. Fuel prices
n. Fuel delivery charges

26. Thermal Power Purchase Agreement (PPA) Operating Characteristics and Costs

PPAs are modeled based upon their tested operating characteristics and contracted costs. Below is a list of typical operating and cost inputs for each thermal PPA.

a. Contract term
b. Maximum Capacity
c. Minimum Capacity Rating
d. Seasonal Deration
e. Heat Rate Profiles
f. Energy Schedule
g. Capacity Payments
h. Energy Payments
i. Maintenance Schedule
j. Forced Outage Rate
k. Emission rates for SO_2, NO_x, CO_2, Mercury and PM
l. Contribution to spinning reserve
m. Fuel prices
n. Fuel delivery charges

27. Renewable Energy PPAs and Owned Operating Characteristics and Costs

PPAs are modeled based upon their tested operating characteristics and contracted costs. Company owned units were modeled based upon their tested operating characteristics and historical or projected costs. Below is a list of typical operating and cost inputs for each renewable energy PPA and owned unit.

a. Contract term
b. Name Plate Capacity
c. Accredited Capacity
d. Annual Energy
e. Hourly Patterns
f. Capacity and Energy Payments
g. Integration Costs

Wind hourly patterns were developed through a "Typical Wind Year" process where individual months were selected from the years 2014-2016 to develop a typical year. Actual generation data from the selected months were used to develop the profiles for each wind farm. For farms where generation data was not complete or not available, data from nearby similar farms were used.

Solar hourly patterns were taken from the Fall 2013 and updated to reflect the ELCC as stated above. The fixed panel pattern is an average of the four orientations and three years (2008-2010) of data and single-axis tracking pattern is an average of three years of data.

28. Generic Assumptions

Generic resources were modeled based upon their expected operating characteristics and projected costs. Below is a list of typical operating and cost inputs for each generic resource.

<u>Thermal</u>

a. Retirement Date
b. Maximum Capacity
c. UCAP Ratings
d. Minimum Capacity Rating
e. Seasonal Deration
f. Heat Rate Profiles
g. Variable O&M
h. Fixed O&M
i. Maintenance Schedule
j. Forced Outage Rate
k. Emission rates for SO_2, NO_x, CO_2, Mercury and PM
l. Contribution to spinning reserve
m. Fuel prices
n. Fuel delivery charges

<u>Renewable</u>

a. Contract term
b. Name Plate Capacity
c. Accredited Capacity
d. Annual Energy
e. Hourly Patterns
f. Capacity and Energy Payments

g. Integration Costs

Tables 13-14 below show the assumptions for the generic thermal and renewable resources.

Table 13: Thermal Generic Information (Costs in 2016 Dollars)

Resource	Coal	Coal w/ Seq	2x1 CC	1x1 CC	CT	Small CT	Biomass
Nameplate Capacity (MW)	511	511	778.3	291.1	229.9	103.4	50
Summer Peak Capacity with Ducts (MW)	NA	NA	766.3	NA	NA	NA	NA
Summer Peak Capacity without Ducts (MW	485	485	649.8	290.2	226.1	100.8	50
Cooling Type	Dry	Dry	Dry	Dry	NA	Wet	Wet
Capital Cost ($/kw)	3,758	5,487	963	1,212	626	1,572	4,731
Electric Transmission Delivery ($/kw)	NA	NA	429	NA	158	NA	NA
Gas Demand ($/kw-yr)	0	0	8.96	11.98	0	0	0
Book life	30	30	40	40	30	30	30
Fixed O&M Cost ($000/yr)	16,973	25,546	7,813	4,299	614	886	5,382
Variable O&M Cost ($/MWh)	2.92	11.00	3.20	1.82	2.36	1.88	4.88
Ongoing Capital Expenditures ($/kw-yr)	9.96	24.31	4.50	4.97	6.11	1.93	14.67
Heat Rate with Duct Firing (btu/kWh)	NA	NA	7725	NA	NA	NA	NA
Heat Rate 100% Loading (btu/kWh)	9,156	12,096	6,822	7,830	9,942	8,867	14,421
Heat Rate 75% Loading (btu/kWh)	9,190	12,565	6,905	8,010	11,048	9,688	14,580
Heat Rate 50% Loading (btu/kWh)	9,710	13,600	6,943	8,583	14,601	11,161	15,570
Heat Rate 25% Loading (btu/kWh)	11,245	17,140	7,583	9,798	NA	15,067	18,650
Forced Outage Rate	6%	7%	3%	3%	3%	2%	4%
Maintenance (weeks/year)	2	5	5	4	2	2	7
CO2 Emissions (lbs/MMBtu)	216	9	118	118	118	118	211
SO2 Emissions (lbs/MWh)	0.447	0.371	0.005	0.005	0.007	0.007	0.577
NOx Emissions (lbs/MWh)	0.45	0.62	0.06	0.05	0.30	0.08	1.01
PM10 Emissions (lbs/MWh)	0.14	0.14	0.01	0.01	0.01	0.01	0.43
Mercury Emissions (lbs/Million MWh)	0.00007	0.00010	0.00000	0.00000	0.00000	0.00000	0.00017

Table 14: Renewable Generic ECC Costs - $/MWh

Year	30% ITC Solar	10% ITC Solar
2020	44	
2021	45	
2022	45	
2023	46	
2024	47	
2025	48	56
2026	49	57
2027	50	58
2028	51	60
2029	52	61
2030	53	62
2031	54	63
2032	55	64
2033	56	66
2034	58	67
2035	59	68
2036	60	70
2037	61	71
2038	62	73
2039	64	74
2040	65	76
2041	66	77
2042	67	79
2043	69	80
2044	70	82
2045		83
2046		85
2047		87
2048		89
2049		90

II. Strategist Modeling Outputs

1. Annual Net Costs and Savings

The PVRR Base annual costs and savings for the proposed Dakota Range project are in Table 1.

Table 1: Annual PVRR Net Costs (Savings) in $millions

Annual Net Costs (Savings) of Dakota Range Project, $M										
	2017	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**
PVRR Base	0	(1)	(0)	1	1	9	6	3	3	(5)
	2027	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
PVRR Base	(32)	(34)	(49)	(39)	(37)	(42)	(57)	(63)	27	25
	2037	**2038**	**2039**	**2040**	**2041**	**2042**	**2043**	**2044**	**2045**	**2046**
PVRR Base	1	(5)	(6)	(28)	(36)	(17)	(14)	(131)	(39)	(18)

2. Expansion Plans

The Reference Case is represented as Table 2 which includes the recently approved 1550MW wind portfolio. The expansion plan with the proposed 300MW Dakota Range wind project is shown as Table 3. Dakota Range is in year 2021, and there are no other wind or utility-scale solar additions after 2021. The 300MW Dakota Range wind project under the Preferred Plan Renewables sensitivity is represented as Table 4 which includes 1650MW of new utility-scale solar by 2030.

Table 2: Reference Case Expansion Plan

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Large Solar	262	-	-	-	-	-	-	-	-	-	-	-	-	-
Generic Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind Projects	-	-	1,150	400	-	-	-	-	-	-	-	-	-	-
CT	-	-	232	-	-	-	-	-	920	690	460	230	230	-
CC	-	-	345	-	-	-	-	-	-	-	-	-	-	-
Sherco CC	-	-	-	-	-	-	-	-	-	-	786	-	-	-

	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Large Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Generic Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind Projects	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT	230	-	-	-	-	230	230	-	230	230	-	-	-	-
CC	778	778	-	778	778	-	-	778	-	-	778	-	-	778
Sherco CC	-	-	-	-	-	-	-	-	-	-	-	-	-	-

	2045	2046	2047	2048	2049	2050	2051	2052	2053	Total
Large Solar	-	-	-	-	-	-	-	-	-	262
Generic Wind	-	-	-	-	-	-	-	-	-	-
Wind Projects	-	-	-	-	-	-	-	-	-	1,550
CT	-	-	-	-	-	-	-	-	-	3,912
CC	-	-	-	778	778	-	-	-	-	7,347
Sherco CC	-	-	-	-	-	-	-	-	-	786

Table 3: Dakota Range Expansion Plan

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Large Solar	262	-	-	-	-	-	-	-	-	-	-	-	-	-
Generic Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind Projects	-	-	1,150	400	300	-	-	-	-	-	-	-	-	-
CT	-	-	232	-	-	-	-	-	920	690	230	460	-	230
CC	-	-	345	-	-	-	-	-	-	-	-	-	-	-
Sherco CC	-	-	-	-	-	-	-	-	-	-	786	-	-	-

	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Large Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Generic Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind Projects	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT	230	460	-	-	-	-	-	-	230	-	-	230	-	-
CC	778	-	-	778	1,556	-	-	778	-	-	778	-	-	-
Sherco CC	-	-	-	-	-	-	-	-	-	-	-	-	-	-

	2045	2046	2047	2048	2049	2050	2051	2052	2053	Total
Large Solar	-	-	-	-	-	-	-	-	-	262
Generic Wind	-	-	-	-	-	-	-	-	-	-
Wind Projects	-	-	-	-	-	-	-	-	-	1,850
CT	-	-	-	-	-	-	-	-	-	3,912
CC	778	-	-	778	778	-	-	-	-	7,347
Sherco CC	-	-	-	-	-	-	-	-	-	786

Table 4: Dakota Range Expansion Plan with Preferred Plan Renewables

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Large Solar	262	-	-	-	-	400	200	300	200	150	-	400	-	-
Generic Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind Projects	-	-	1,150	400	300	-	-	-	-	-	-	-	-	-
CT	-	-	232	-	-	-	-	-	230	690	230	230	230	-
CC	-	-	345	-	-	-	-	-	-	-	-	-	-	-
Sherco CC	-	-	-	-	-	-	-	-	-	-	786	-	-	-

	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044
Large Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Generic Wind	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Wind Projects	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CT	920	-	-	-	230	230	-	-	230	230	-	-	230	-
CC	-	778	-	778	778	-	-	778	-	-	778	-	-	-
Sherco CC	-	-	-	-	-	-	-	-	-	-	-	-	-	-

	2045	2046	2047	2048	2049	2050	2051	2052	2053	Total
Large Solar	-	-	-	-	-	-	-	-	-	1,912
Generic Wind	-	-	-	-	-	-	-	-	-	-
Wind Projects	-	-	-	-	-	-	-	-	-	1,850
CT	-	-	-	-	-	230	230	-	230	4,602
CC	778	-	-	778	778	-	-	-	-	6,569
Sherco CC	-	-	-	-	-	-	-	-	-	786

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-____

VERIFICATION

STATE OF MINNESOTA)
)ss.
COUNTY OF HENNEPIN)

Philip Joseph Martin, being first duly sworn on oath, deposes and says that he is the Director of Resource Planning and Bidding for Xcel Energy Services Inc. on behalf of Applicant Northern States Power Company, a Minnesota corporation, in the above-captioned matter, that the testimony and schedules submitted in the above-captioned matter under his name were prepared under his direction, that he knows the contents thereof, and that the same is true and correct to the best of his knowledge and belief.

Philip Joseph Martin

Subscribed and sworn to before me on this 10th day of October, 2017.

CYNTHIA D. HARRINGTON
Notary Public, State of Minnesota
My Commission Expires
January 31, 2020

Notary Public
My Commission Expires: 1-31-2020