PUBLIC DOCUMENT:

TRADE SECRET INFORMATION EXCISED

Direct Testimony and Schedules
Steven W. Wishart

Before the North Dakota Public Service Commission
State of North Dakota

In the Matter of the Application of Northern States Power Company for an Advance Determination of Prudence for a 200 MW Power Purchase Agreement with the Courtenay Wind Project

Case No. PU-13_____
Exhibit ___(SWW-1)

In the Matter of the Application of Northern States Power Company for an Advance Determination of Prudence for a 200 MW Power Purchase Agreement with the Odell Wind Project

Case No. PU-13_____
Exhibit ___(SWW-1)

In the Matter of the Application of Northern States Power Company for an Advance Determination of Prudence for the 200 MW Pleasant Valley Wind Project

Case No. PU-13_____
Exhibit ___(SWW-1)

Resource Planning Testimony

July 26, 2013

PUBLIC DOCUMENT:

TRADE SECRET INFORMATION EXCISED

Table of Contents

Schedules

PUBLIC DOCUMENT:

TRADE SECRET INFORMATION EXCISED

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND TITLE.

A. My name is Steven W. Wishart. I am Director of Resource Planning and Bidding for Xcel Energy.

Q. PLEASE DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have worked for Xcel Energy since 2005 in the areas of demand-side management and resource planning. In my current role, I am responsible for the direction and oversight 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.

My responsibilities include assisting the Company in making reasonable and prudent acquisition decisions for electric generation resources. I maintain our resource planning model, Strategist, and conduct economic evaluations of resource additions and bid processes for new resource acquisitions. My resume is provided as Exhibit___(SWW-1), Schedule 1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I discuss the resource additions that the Company is proposing, discussing the quantitative and qualitative customer and Company benefits presented in our Application. My testimony also provides:

- The background for the Company's February 2013 Request For Proposals for wind generation projects, and the RFP process;

- The Company's analysis of the bids received through the RFP process, which narrowed the field to the three 200 MW resources we propose to add to our system;
- A description of the proposed resource additions:
  - A PPA with Geronimo Energy for the 200 MW Courtenay wind project in Stutsman County, North Dakota;
  - A PPA with Geronimo for the Odell wind project located near Mountain Lake, Minnesota; and
  - The 200 MW Pleasant Valley wind project being developed by RES Amercias near our Grand Meadow Wind Farm in southeastern Minnesota, which, upon completion, RES Americas will transfer to the Company; and
- The effects of our proposed resource addition on the Company's pending peaking plan proposal in Case Nos. PU-13-194 and PU-13-195.

I conclude my testimony with a discussion of the development and operational risks that the Company identified for these Projects, and the steps we have taken to mitigate those risks.

II. REQUEST FOR PROPOSAL PROCESS

Q. WHAT PROMPTED THE COMPANY TO ISSUE AN RFP FOR WIND GENERATION?

A. The wind RFP was part of our overall resource planning process, which is conducted for the integrated NSP System to meet the needs of all customers in North Dakota, South Dakota, Minnesota, Wisconsin, and Michigan.

Our 2011-2025 Resource Plan identified the need for additional wind resources, if these resources were competitively-priced relative to traditional generation. Part of our strategic plan was to monitor the market for wind energy and pursue new resources when it appeared they were likely to be cost effective. When the January 2013 federal legislation extended the Production Tax Credit to projects that begin construction activities by the end of 2013, we believed there may be opportunities to secure additional wind resources for our integrated system at cost-effective prices, since the PTC can account for a substantial portion of a wind project's total cost.

Q. PLEASE DESCRIBE THE COMPANY'S RFP PROCESS.

A. We issued the RFP on February 18, 2013, and notified national and regional media and trade press. In the notification, we provided a link to our website where the RFP, model Power Purchase Agreement, and standard bidder forms were located.[1]

The RFP was open to proposals of any size up to 200 MW and of various structures including utility ownership, PPA or any combination thereof with no preference given to any particular type of structure. Bidders were encouraged to e-mail questions or call the designated point of contact for the RFP prior to the submission of their proposals. The RFP outlined the submittal requirements including completion of standard bidder forms designed to ensure adequate and consistent collection of information from

[1] These documents are available at xcelenergy.com at: http://www.xcelenergy.com/About_Us/Our_Company/Projects_and__RFPs/2013_Upper_Midwest_Wind_Power_Request_for_Proposals

each bidder. The RFP specified that bids must be delivered to the Company by April 1, 2013 at 5:00 PM CDT.

Bids remained sealed until the morning of April 3, 2013. Our Resource Planning department led the evaluation team. All bids were logged on a tracking spreadsheet and maintained in a locked room. Copies of proposals with a PPA component were provided to our Purchased Power group for further evaluation and copies of proposals with an ownership component were delivered to our Business Development group. Proposals containing offers for both PPAs and ownership structures were provided to both groups.

Q. WHAT WAS THE REPONSE TO THE RFP?

A. The RFP generated proposals for 57 projects comprising approximately 6,300 MW of distinct resources. Many projects contained several PPA and ownership options with associated variations in size and price. Proposed project sites were located in Illinois, Iowa, Minnesota, North Dakota, South Dakota, and Wisconsin.

III. COMPANY ANALYSIS OF PROPOSALS

Q. HOW DID THE COMPANY ANALYZE THE PROPOSALS?

A. We performed an initial screening of bids based on our calculation of levelized cost. The screening was designed to provide an initial gauge of pricing and determine if the Company should move forward with the RFP. We used a revenue requirements model to calculate the levelized cost for each ownership proposal using information provided in the bid and certain internal estimates

as needed. We performed the same levelized calculation for the PPA proposals using energy pricing provided in each bid, and summarized and sorted all bids by levelized cost. Results from this initial screening highlighted the attractive pricing of projects offered. The results of our initial screening is included with my testimony as Exhibit___(SWW-1), Schedule 2.

The initial screening process allowed us to identify the most cost-effective projects so we could focus our efforts on those having the best potential to provide long-term value to our customers. Based on the distribution of levelized cost we narrowed our review to bids that were at or below $29/MWh. We chose the cutoff price of $29/MWh, as it provided for a reasonable number of the most cost-effective proposals from which to focus further review efforts. There were 14 projects within the established levelized price threshold area.

Q. WHAT WERE THE NEXT STEPS TO FURTHER NARROW THIS FIELD OF PROPOSED PROJECTS?

A. A significant consideration of any project is its ability to interconnect with the transmission system. Therefore, our Transmission Access group performed a detailed multi-factor review of the status of each project's MISO interconnection request and potential transmission requirements. This review identified potential significant issues around transmission interconnection cost and curtailment risk for several of the projects. Based on this analysis, the Transmission Access group recommended that a number of these projects be eliminated from further consideration.

The Purchased Power group performed an assessment of the PPA proposals based on the information provided by the Transmission Access group and information provided in the bids. Based on that analysis, Geronimo's Courtenay and Odell proposals were selected.

Q. HOW WAS THE PLEASANT VALLEY PROJECT SELECTED?

A. The Business Development group also used the information provided by the Transmission Access group, along with other information provided in the bids, to determine the potential viability of develop/transfer projects. From this assessment, Business Development identified five projects that appeared attractive from an ownership perspective.

The Pleasant Valley project appeared at this point to have characteristics that stood out from the others. Other projects were of potential interest, but had characteristics that were less attractive from an ownership perspective. As the result of the analysis, attention was focused on Pleasant Valley and one other proposal by RES Americas, with discussion continuing with one additional developer.

Q. WHAT WAS THE NEXT STEP IN THE PROCESS THAT LED TO THE COMPANY TO ENTER INTO AGREEMENTS FOR THE COURTENAY, ODELL, AND PLEASANT VALLEY PROJECTS?

A. The Business Development and Purchased Power areas proceeded with due diligence and contract negotiations on their recommended projects. This involved evaluating a number of measures including price, energy production profile, curtailment risk, interconnection and transmission requirements and

costs, environmental risk, developer experience and several other criteria. The process resulted in the Company entering into agreements for the Courtenay, Odell, and Pleasant Valley projects.

Q. DID THE COMPANY CONDUCT AN EVALUATION OF THE FAIRNESS OF ITS WIND RFP PROCESS?

A. Yes. We engaged an independent auditor to examine whether the process for obtaining and evaluating responses to the RFP was biased. The independent auditor's report, included as Exhibit___(SWW-1), Schedule 3 to my testimony, concluded that the Company's RFP process was free from bias, and afforded each proposal equitable care and consideration. In addition, the report noted that the process was rigorous, robust and consistent – and that the Company administered the process professionally and was thorough in its efforts.

IV. PROJECT DESCRIPTIONS

Q. PLEASE DESCRIBE THE COURTENAY PROJECT.

A. The Courtenay Project is a 200 MW wind energy generation facility. It is located along the edge of the Missouri Coteau in east-central North Dakota, northeast of Jamestown. We have entered into a 20-year PPA with Geronimo Energy to purchase all of the electric energy produced at Courtenay.

The project covers 24,900 acres of land in northeastern Stutsman County, and will consist of up to 124 wind turbine generators, depending on final turbine model selected, and associated infrastructure. Associated infrastructure includes access roads, electrical collection system, meteorological monitoring

stations, a project collector substation, a transmission line, and an operations and maintenance facility.

The Courtenay project will interconnect to the Otter Tail Power 345/115kV substation located north of Jamestown, North Dakota. The project is in the February 2013 Definitive Planning Phase of the MISO Generator Interconnection Process.

Q. WHAT IS THE COURTENAY PROJECT'S CONSTRUCTION SCHEDULE?

A. The bulk of project construction is expected to begin in the spring of 2014. However, engineering, procurement and some construction will occur in 2013. Under terms of the Agreement, commercial operation shall occur no sooner than November 30, 2014 and no later than September 30, 2015. This schedule is designed such that the project will qualify for the federal PTC, which will provide cost benefits to our customers.

Q. WHAT ARE THE TERMS OF THE COURTENAY PPA?

A. The PPA contains usual and customary terms for a transaction of this type, with the condition precedent that the Company must receive an Advance Determination Of Prudence from the Commission before proceeding with the PPA. We provide the Courtenay PPA as Trade Secret Exhibit___(SWW-1), Schedule 4 to my testimony.

The purchase price of electric energy from Courtenay starts at **[TRADE SECRET BEGINS…**

…TRADE SECRET ENDS]. We calculate the levelized cost of energy

over the term of the agreement to be **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]**.

Q. PLEASE DESCRIBE THE ODELL PROJECT.

A. The Odell Project is a 200 MW wind energy generation facility located in a rural, agricultural area near Mountain Lake, Minnesota. The Project's footprint spans approximately 22,000 acres across parts of Cottonwood, Jackson, Martin, and Watonwan Counties. We have entered into a 20-year PPA with Geronimo Energy to purchase all of the electric energy produced at Odell.

The project will consist of up to 124 wind turbine generators and associated infrastructure. Associated infrastructure includes access roads, electrical collection system, meteorological monitoring stations, a project collector substation, a transmission line, a new interconnection substation, and an operations and maintenance facility.

The Odell project will interconnect at a new 345/115 kV substation on the Lakefield Generation – Fieldon segment of Northern States Power's Lakefield Junction – Wilmarth 345 kV transmission line. Odell is part of the August 2012 Definitive Planning Phase of the MISO Generator Interconnection Process.

Q. WHAT IS THE ODELL PROJECT'S CONSTRUCTION SCHEDULE?

A. The bulk of construction of the Odell Project is expected to begin in the spring of 2014. However, engineering, procurement and some construction

will occur in 2013. Under terms of the Agreement, commercial operation shall occur no sooner than November 30, 2014 and no later than December 31, 2015. This schedule is designed such that the project will qualify for the federal PTC, which will provide cost benefits to our customers.

Q. WHAT ARE THE TERMS OF THE ODELL PPA?

A. The terms are similar to those we negotiated with Geronimo for the Courtenay PPA, with receipt of an Advance Determination Of Prudence from the Commission being a condition precedent to proceeding with the PPA. We provide the Odell PPA as Exhibit___(SWW-1), Schedule 5 to my testimony. The purchase price of electric energy from Odell starts at **[TRADE SECRET BEGINS…**

…TRADE SECRET ENDS]. We calculate the levelized cost of energy over the term of the Agreement to be **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]**.

Q. PLEASE DESCRIBE THE PLEASANT VALLEY PROJECT.

A. The Pleasant Valley project is a 200 MW wind energy generation facility that will be located in close proximity our Grand Meadows wind facility on 52,000 acres of land in Mower and Dodge Counties, near Austin, Minnesota. RES Americas will develop the Pleasant Valley project, and upon completion, transfer ownership to the Company. We will then dissolve the project entity and own and operate Pleasant Valley.

The Pleasant Valley project will consist of **[TRADE SECRET BEGINS…**

…TRADE SECRET ENDS] wind turbine generators

and associated infrastructure. Associated infrastructure includes access roads, electrical collection system, meteorological monitoring stations, a project collector substation, a transmission line, and an operations and maintenance facility. An analysis of the site-specific wind data was conducted by our consultant, V-Bar, utilizing the specific turbines planned for the project. The analysis predicted a net capacity factor of 45.80 percent for the wind turbines, which was used for our final levelized-cost analysis.

The Pleasant Valley project will interconnect to Great River Energy's 345/161 kV Pleasant Valley substation. The project has applied and will participate in the MISO August 2013 Generator Interconnection Study cycle, which will identify all required transmission upgrades required for the project to interconnect to the transmission grid.

Q. WHAT IS THE PROJECT'S CONSTRUCTION SCHEDULE?

A. Construction is expected to begin in the late 2013, primarily involving certain activities related to engineering, procurement and construction, as necessitated by IRS requirements for PTC eligibility. The current project schedule contemplates commercial operation in late 2015. Again, the project schedule is designed to take advantage of the significant federal PTC benefits.

Q. PLEASE DESCRIBE HOW XCEL ENERGY WILL ACQUIRE THE PLEASANT VALLEY PROJECT FROM RES AMERICAS.

A. We will purchase the Pleasant Valley project pursuant to a Purchase and Sale Agreement (PSA) with RES Americas. Under the PSA, the Company will be purchasing the Limited Liability Company (LLC) that holds all of the project

assets, such as the generating facilities, real estate, and contracts for the project.

We have agreed to structure the transaction as a purchase of an LLC to allow RES Americas some flexibility in development of the Project, to create efficiencies in the mechanics of the Project transfer by taking advantage of certain legal merger constructs, and to provide certain tax benefits during development. This structure requires RES Americas to assume construction risk throughout the development and construction phase of the Project, as they are responsible for the physical construction of the Project.

After the closing of the purchase, the Company will dissolve the LLC and reflect the Project assets on its books as if Pleasant Valley were any other Company owned generating facility. While the Company has not engaged in any transactions structured in this way in the past, our affiliate, Public Service Company of Colorado, has recently and successfully consummated such a transaction.

Q. WHAT ARE THE TERMS OF THE PSA?

A. The PSA contains usual and customary terms for a transaction of this type, with the condition precedent that the Company must receive an Advance Determination Of Prudence from the Commission before proceeding with the PSA. We provide the Company's PSA with RES Americas as Exhibit___(SWW-1), Schedule 6 to my testimony.

Q. WHAT ARE THE COSTS OF THE PLEASANT VALLEY PROJECT?

A. We estimate the total capital cost of Pleasant Valley will be approximately **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]**, including Xcel Energy's anticipated development oversight and ownership transfer closing costs. Our PSA with RES Americas calls for payments of approximately **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]** for development of the project. We estimate Xcel Energy's development oversight and ownership transfer costs will be up to $4 million. We have included an additional **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]** in our capital estimate and project analysis to cover the risk of additional transmission interconnection costs the Company may be responsible for. We calculate the 25-year, levelized cost of electricity to be **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]**, based on all capital costs and our estimates of O&M.

V. STRATEGIST ANALYSIS OF PROJECTS

Q. HOW DID THE COMPANY EVALUATE THE COST-EFFECTIVENESS OF THE PROJECTS?

A. We used the Strategist resource planning model to evaluate the cost effectiveness of the proposed projects. The Strategist Planning model simulates the operation of the NSP System and estimates the total cost of energy over the life of the projects on a present value basis. We use the model to test results under a range of input assumptions. Each proposed wind project was modeled individually, and as a combined portfolio. To assess their impact on customer costs, we simulated the operation of the NSP

System over the next 40 years, with and without the addition of the 600 MW of wind generation proposed in this Petition.

Q. WHAT ASSUMPTIONS DID THE COMPANY MAKE IN ITS EVALUATION TO INCREASE THE CONFIDENCE LEVELS OF ITS MODELING RESULTS?

A. To ensure reasonable assessment of the benefit of the proposed wind projects, the Strategist model included a number of conservative input assumptions regarding operation and wind integration. The model included higher than average assumptions for curtailment, significant wind integration costs, and estimates for transmission losses and congestion, while excluding financial benefits derived from lower air emissions, consistent with North Dakota's requirements.

Wind generation produces financial benefits by reducing the costs of both fossil fuel generation and purchased energy from the market. When wind resources are producing energy, generation from convential resources such as natural gas plants can be reduced without impacting the reliability of service to our customers. The energy from our proposed 600 MW wind portfolio is expected to avoid the purchase of over 170 billion cubic feet of natural gas over their contract and service lives, as well as avoid the purchase of almost 13,000 gigawatt hours of energy. The Strategist analysis accounts for these cost savings, as well as the impact of the capital commitments or PPA payments associated with the wind generation additions.

Q. WHAT WERE THE COST BENEFITS OF THE PROJECTS AS QUANTIFIED BY THE STRATEGIST ANALYSIS?

A. The analysis, with its conservative assumptions, shows that customers will save over $180 million (net present value) over the term of the contracts, as summarized in Table 1 below. The net present value of savings to our customers is refereed to as the Present Value of Revenue Requirements, or PVRR. In the case of the proposed wind projects, the total savings are higher than the total costs, which results in negative PVRR impacts – translating to cost savings for our customers.

Table 1: Net PVRR Impact (Savings)

PVRR *($ millions)*	**Reference Case** *($0/ton CO_2)*	**Low Gas** *(1.7% growth rate)*
Pleasant Valley 200MW	($90)	($17)
Odell 200MW	($53)	($1)
Courtenay 200MW	($60)	($10)
Portfolio 600MW	($184)	($14)

As shown above, even if natural gas prices grow at only half the forecasted rate (1.7 percent versus a baseline of 3.4 percent), the projects are still expected to create benefits for our customers.

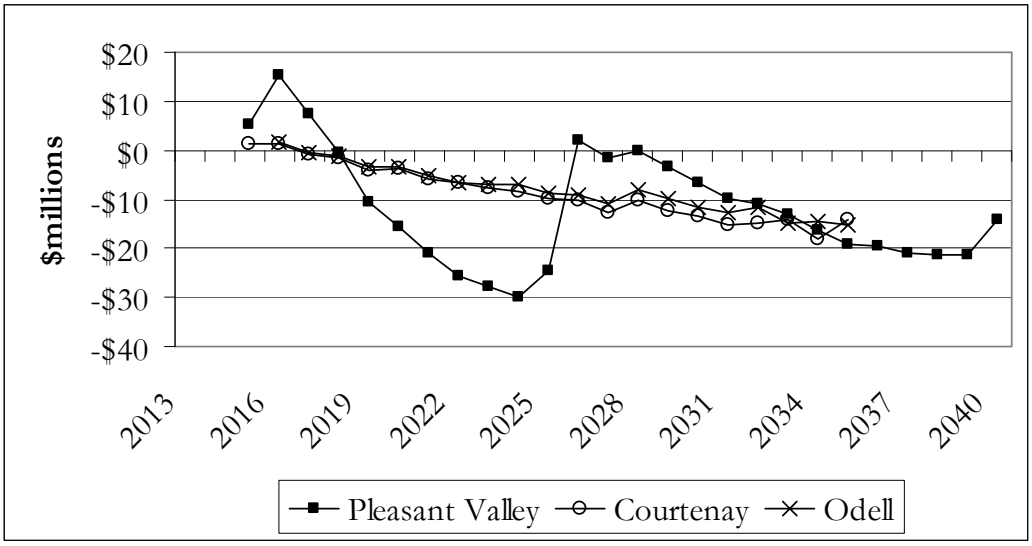
Q. HOW ARE THESE COST SAVINGS SPREAD OVER TIME?

A. Figure 1 below portrays the annual net costs or benefits of each project individually. The net present value of these annual costs is equivalent to each project's PVRR.

PUBLIC DOCUMENT:

TRADE SECRET INFORMATION EXCISED

Figure 1: Annual Net Costs (Savings)



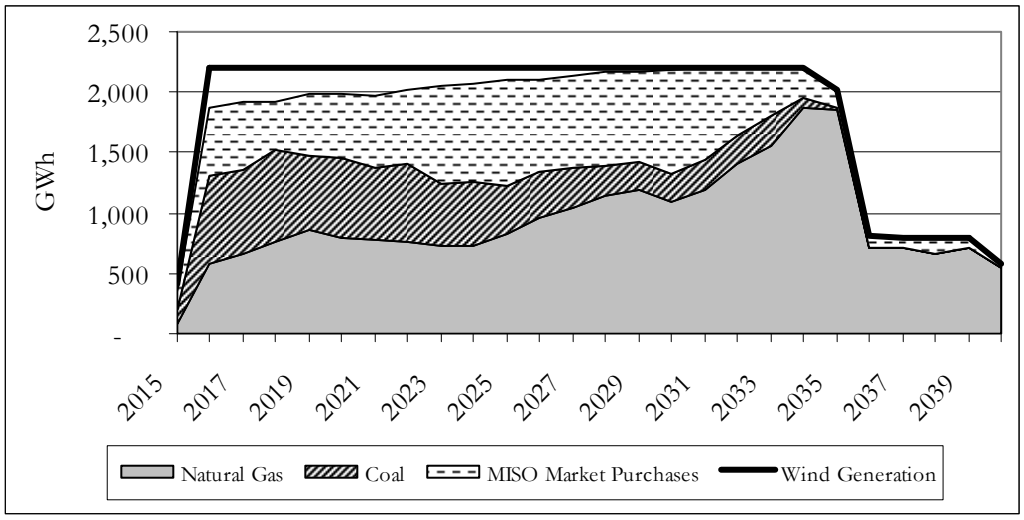
The Courtenay and Odell PPAs have almost identical annual net benefits that gradually increase over time. The benefits are created by wind energy displacing higher cost fossil fuel generation. The Pleasant Valley project provides substantially larger benefits during the first ten years when the federal PTC is available, then continues to provide savings to our customers after the 20-year PPAs have expired.

Initially, there is a short period of time during which the cost of the Pleasant Valley project is higher than the benefits realized from lower fuel costs. This is because when Company-owned projects are first brought into service, their book value (and associated impact on base rates) is at its highest point. In subsequent years as the resource is depreciated, the cost to our customers falls, and creates a much larger benefit to our customers that in this case occurs in 2018 through 2025. Under baseline assumptions, the Pleasant Valley Project has the highest NPV benefits to our customers beyond the first years.

Q. WHAT WILL THE ANNUAL IMPACTS BE ON THE NSP SYSTEM?

A. The addition of 600 MW of wind power on our system displaces approximately 2,200 gigawatt-hours of electricity production annually at traditionally-fired plants. Figure 2 below illustrates the results of the Strategist dispatch simulations. On average, the wind will displace over $100 million annually in generation from other resources. Most of the displaced energy (75 percent) will be either natural gas generation or energy purchased from the MISO market. A small proportion will also be from coal and other generation resources.

Figure 2: Strategist Simulations – Displaced Energy



Q. WHAT IS THE IMPACT OF CURTAILMENT ON THE PROJECTS' COST-EFFECTIVENESS?

A. Figure 2 above also demonstrates that the Strategist analysis showed a significant amount of curtailment. The empty area between the total Wind Generation line and the MISO Market Purchases area represents excess

energy that could not be utilized by the dispatch simulation, and is equivalent to wind curtailment due to low customer demand at times of high wind generation.

From 2015 through 2025, this accounts for more than ten percent of the total energy produced by the three projects. This is a very conservative estimate of curtailment, and is a result of how the MISO market is modeled in Strategist. Currently, less than 1.4 percent of wind is actually curtailed on the NSP System. Having the conservative 10+ percent estimate of curtailment built into our model ensures that the net benefits to our customers are not being overstated, and that the realized customer bill reductions may actually be larger than forecasted.

Q. WHAT OTHER BENEFITS DO THE 600 MW OF WIND PROVIDE?

A. The addition of the 600 MW of new resources also provides qualitative benefits, because they act as a hedge against higher natural gas prices and potential future carbon regulations. If the Company were not to acquire these resources, future levels of natural gas consumption and MISO market purchases would be higher, creating higher cost uncertainty for our customers.

Strategist simulations indicate that the additional 600 MW of wind will avoid the need for seven bcf of natural gas and over 600 GWh of MISO market purchases annually; over the lifetime of the projects, a total of 176 bcf of natural gas and over 13,000 GWh will be displaced.

Likewise these resources will create a hedge against potential federal CO2

legislation. It is unclear when significant CO2 legislation might be imposed and what form it may take (cap and trade, carbon tax, strict annual limits), but these resource additions will add over 2,000 GWh of carbon-free energy annually, reducing our annual CO2 emission by approximately 1.2 million tons or five percent. This will reduce our exposure to carbon regulation and will lower the cost of compliance with any CO2 goal or target level.

To illustrate the benefit of these projects, Table 2 below shows the base case volumes of natural gas, market purchases and CO2 emissions – and the deltas against these factors for the studied projects.

Table 2: Hedge Value

Total System 2015-2050	**Natural Gas** *bcf*	**Market Purchases** *GWh*	**CO2** *Million tons*
BASE	2,525	96,707	700
Pleasant Valley	(77)	(5,717)	(12)
Courtenay	(48)	(4,425)	(9)
Odell	(50)	(4,186)	(9)
All	(176)	(12,864)	(29)

Q. WHAT IS THE ESTIMATED RATE IMPACT ON 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 proposed wind projects. Our Strategist analysis forecasts that the cost of Pleasant Valley and the PPA projects will be more than offset by decreases in the cost of fossil fuel and other purchased energy.

While the 600 MW of wind resources represents the largest individual

renewable energy acquistion we have made, the relative impacts are small due the large size of the NSP System. Table 3 below provides estimates of how average rates will be impacted by the proposed projects. Over the first four years, the average impact on a typical residential bill would be a monthly *increase* of 18 cents. Over the next seven years (2019-2025), our models forecast an average *decrease* of 51 cents per month, resulting in a net decrease for customers.

Table 3: Rate Impacts

2013 Wind RFP Rate Impacts

	2015	2016	2017	2018	2019	2020
Base Rates - Pleasant Valley	0.02¢/kWh	0.08¢/kWh	0.07¢/kWh	0.05¢/kWh	0.03¢/kWh	0.02¢/kWh
Fuel Clause - Geronimo	0.01¢/kWh	0.08¢/kWh	0.08¢/kWh	0.08¢/kWh	0.08¢/kWh	0.08¢/kWh
Wind Integration & Congestion	0.01¢/kWh	0.03¢/kWh	0.02¢/kWh	0.02¢/kWh	0.02¢/kWh	0.03¢/kWh
Avoided Fuel & Purchased Power	(0.02¢/kWh)	(0.13¢/kWh)	(0.14¢/kWh)	(0.15¢/kWh)	(0.17¢/kWh)	(0.17¢/kWh)
Net Rate Impact	**0.01¢/kWh**	**0.05¢/kWh**	**0.02¢/kWh**	**0.00¢/kWh**	**(0.03¢/kWh)**	**(0.05¢/kWh)**

	2021	2022	2023	2024	2025
Base Rates - Pleasant Valley	0.01¢/kWh	0.01¢/kWh	0.01¢/kWh	0.00¢/kWh	0.02¢/kWh
Fuel Clause - Geronimo	0.08¢/kWh	0.08¢/kWh	0.09¢/kWh	0.09¢/kWh	0.09¢/kWh
Wind Integration & Congestion	0.03¢/kWh	0.03¢/kWh	0.03¢/kWh	0.03¢/kWh	0.03¢/kWh
Avoided Fuel & Purchased Power	(0.18¢/kWh)	(0.19¢/kWh)	(0.20¢/kWh)	(0.21¢/kWh)	(0.22¢/kWh)
Net Rate Impact	**(0.06¢/kWh)**	**(0.07¢/kWh)**	**(0.08¢/kWh)**	**(0.09¢/kWh)**	**(0.08¢/kWh)**

Q. HOW WAS THE STRATEGIST MODELING OF THE THREE PROJECTS DEVELOPED?

A. We modeled the PPA alternatives in Strategist in accordance with the bidder-supplied data contained in the proposals. For the base analysis, we used the capacity factors that the developers provided in their bids. To test the impact of the capacity factor predictions, we conducted sensitivity tests in Strategist where the annual generation was varied by plus and minus 5 percent.

The cost for Courtenay and Odell are modeled as simple $/MWh cost rates that adjust once per year to account for the fixed price escalations specified in

the agreements. The hourly prices are multiplied by hourly generation simulated in Strategist to derive the total annual costs.

For Company-owned projects, the upfront purchase price needs to be translated into a projection of annual revenue requirement associated with financing, operations, depreciation, and taxes. Projections of upfront and on-going capital investments and annual operating and maintenance expenses also need to be developed. To test how variations from the capital expenditures and O&M would impact the overall cost-effectiveness of the projects, we conducted sensitivity tests in Strategist of plus and minus 25 percent of projected on-going capital investments and O&M expenses.

The economic benefit of an owned-wind project is highly-dependent on the annual generation from the site. Each additional MWh produced by a Company-owned project increases the value of the project because the higher the production, the lower the average costs will be, and therefore, the larger the benefits. To test how average capacity factors impact the economic value of Pleasant Valley performed Strategist sensitivity using +/- 5 percent of the expected annual generation. The base assumption for the life of each ownership option was 25 years, and sensitivities were performed for 20-year and 30-year lives.

Q. PLEASE DESCRIBE THE OTHER PRINCIPAL ELEMENTS OF THE MODELING.

A. The other principal elements of the modeling include Typical Wind Year (TWY) profiles for existing NSP wind farms that are geographically proximate, MISO Effective Load Carrying Capability (ELCC) analysis, and

transmission congestion and line losses for new resources.

The TWY profiles were adjusted to match the target annual generation. The Strategist model also included an additional wind integration cost to account for incremental operating reserves that may be required to support the intermittent nature of the projects. The levelized cost of the wind integration was $3.62/MWh, equivalent to over $7 million annual.

In accordance with the latest MISO ELCC analysis, we modeled Courtenay and Odell as having a 13.3 percent accredited capacity value. However, per MISO's tariff and business practices, in order to receive accreditation as a capacity resource, it must have firm delivery rights either with Network Resource Interconnection Service or firm transmission service (Network Integration Transmission Service or Firm Point-to-Point Transmission Service). Our expectation is that these resources will not be given this designation until 2021 when various transmission system upgrades, including MISO's MVP projects, are complete. Our modeling efforts reflect the expected capacity accreditation in 2021.

The Strategist model does not explicitly model transmission congestion and line losses for new resources. To ensure that we are accounting for all the costs associated with our wind proposal, we included the congestion and line loss estimates from MISO's 2012 Promod model. The Promod model contains detailed information on the transmission topology in MISO, and has the ability to forecast hourly prices at individual nodes throughout the system. It is the same model that MISO used in their most recent round of

transmission planning analysis, and contains all planned upgrades to the transmission system that may impact transmission congestion in the future. The difference in price between any two locations within MISO is interpreted at the combined impact of transmission system congestion and line losses.

Q. WHAT WERE THE RESULTS OF THE STRATEGIST MODELING?

A. We evaluated the Projects as a total portfolio and as individual projects. The Strategist results show these new wind resources will result in net savings for our customers under all sensitivity tests conducted. The Pleasant Valley project consistently has the highest PVRR savings, even under a PPA-comparable 20-year operating life, the minus 5 percent capacity factor, and the plus 25 percent ownership cost sensitivities.

Table 4: PVRR Results ($millions)

	Base	Low Gas	30 Year Operating Life	20 Year Operating Life	+5% Capacity Factor	-5% Capacity Factor	+25% On-Going Ownership Costs	-25% On-Going Ownership Costs
Base Case (No Wind)	$40,595	$37,249	$40,595	$40,595	$40,595	$40,595	$40,595	$40,595
Pleasant Valley	$40,505	$37,232	$40,476	$40,565	$40,489	$40,520	$40,536	$40,500
Odell	$40,542	$37,248	$40,542	$40,542	$40,540	$40,544	$40,542	$40,542
Courtenay	$40,535	$37,239	$40,535	$40,535	$40,533	$40,537	$40,535	$40,535
All 3 Projects	$40,412	$37,235	$40,382	$40,472	$40,395	$40,428	$40,443	$40,407

Table 5: Incremental PVRR from Base Case ($millions)

	Base	Low Gas	30 Year Operating Life	20 Year Operating Life	+5% Capacity Factor	-5% Capacity Factor	+25% On-Going Ownership Costs	-25% On-Going Ownership Costs
Base Case (No Wind)	$0	$0	$0	$0	$0	$0	$0	$0
Pleasant Valley	($90)	($17)	($120)	($31)	($106)	($75)	($59)	($95)
Odell	($53)	($1)			($55)	($51)		
Courtenay	($60)	($10)			($62)	($58)		
All 3 Projects	($184)	($14)	($213)	($124)	($200)	($167)	($152)	($189)

As indicated in the PVRR tables above, all projects provide significant cost savings to our customers, both individually and as a portfolio, even under the conservative sensitivity cases studied.

Q. DID THE COMPANY CALCULATE THE STRATEGIST RESULTS IN TERMS OF LEVELIZED COST?

A. Yes. Levelized prices are a fixed $/MWh price that have the same NPV as the actual cost streams generated by Strategist. I have found that putting the Strategist results in terms of $/MWh is more intuitive and leads to better understanding of the analysis. 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 displaced generation from fossil fuel resources, but the model also tracks capacity credits based on the cost of natural gas combustion turbines. Table 6 below illustrates how the levelized costs of the agreements are more than offset by the value of avoided generation.

Table 6: Levelized Costs Analysis - $/MWh

	Pleasant Valley	**Odell**	**Courtenay**
	[TRADE SECRET BEGINS…		
Rev. Reqs / PPA Price			
Wind Integration			
Congestion/Line Losses			
Avoided Fossil Fuel			
Capacity Credit			
			…TRADE SECRET ENDS]
Net Cost (Benefit)	($11.11)	($8.18)	($9.20)

VI. IMPACT ON CAPACITY NEED

Q. WILL THE PROPOSED 600 MW RESOURCE ACQUISITION AFFECT THE COMPANY'S NEED FOR ADDITIONAL CAPACITY RESOURCES IN THE 2017-2019 TIME FRAME?

A. No. As noted in our Application for natural gas peaking units in Case Nos. PU-13-194 and PU-13-195, we have an identified capacity need of 150-500 MW in the 2017-2019 timeframe. Because our proposed acquisition of wind generation is not expected to receive a capacity credit from MISO until 2021, the addition of these projects to our system does not affect the identified capacity need.

Q. WILL THE COMPANY'S PROPOSED ACQUISITION OF 600 MW OF ADDITIONAL GENERATION HAVE ANY AFFECT ON ITS PROPOSED RED RIVER VALLEY UNITS?

A. That is not clear at this time. The energy produced by our additional wind resources will impact the daily dispatch of other resources, thereby potentially affecting the type of resource selected to meet the identified capacity need. We believe that this issue is best resolved in Case Nos. PU-13-194 and PU-13-195.

VII. PROJECT RISK MANAGEMENT

Q. PLEASE DESCRIBE WHAT PROJECT RISK MANAGEMENT REFERS TO.

A. With any large generating project, there are risks associated with the development of the Courtenay, Odell, and Pleasant Valley Projects. We

believe that we have identified, assessed, and mitigated major risks through prudent contracting practices, and that it is reasonable and in our customers' interests for the Commission to find the Projects are prudent additions to Xcel Energy's integrated system.

Q. WHAT RISKS DID THE COMPANY IDENTIFY?

A. The two principal categories of risk are *development* risks and *operational* risks. Development risks for these three projects include the risks associated with the federal PTC, construction and capital issues, transmission interconnection, and environmental issues. The operational risks relate to power production and curtailment.

Q. PLEASE DESCRIBE THE FEDERAL PTC RISK.

A. The January 2013 renewal of the PTC provides a tax credit for those projects that have begun construction by December 31, 2013. IRS guidelines consider commencement of construction to have occurred when physical work of a significant nature has started or five percent of the total cost of the facility has been incurred and the developer makes continuous efforts to complete the facility thereafter.

We believe these projects will meet the requirements necessary to qualify for the PTC, and that the risk has been reasonably mitigated in the relevant agreements. As it relates to the Courtenay and Odell Projects, Geronimo assumes the risk of qualifying for the PTC if the Projects are unable to meet the requirements. Under the PSA for the Pleasant Valley Project, RES Americas is required to **[TRADE SECRET BEGINS…**

…TRADE SECRET ENDS].

The PSA also contains extensive provisions **[TRADE SECRET BEGINS…**

…TRADE SECRET ENDS].

Q. WHAT ARE THE CONSTRUCTION AND CAPITAL RISKS?

A. By contracting only for the output of the Courtenay and Odell projects, the Company has fully-shifted the risks of development and construction to Geronimo Energy.

For the Pleasant Valley Project, the Company will carry some construction and out-year capital contribution risks for the project since we will own it. We believe the PSA with RES Americas is equitable, and reasonably shifts the bulk of these risks on the developer. For example, by purchasing a turnkey project, the Company mitigates its actual construction risk since RES Americas must construct the project prior to the Company purchasing it. Additionally, we have required RES Americas, through the PSA, to meet our technical criteria for Company-owned facilities.

The parties have also negotiated a customary holdback provision to provide

for the completion of certain punch list items after the closing, as well as an additional holdback amount in the event that curable breaches, not to exceed **[TRADE SECRET BEGINS… …TRADE SECRET ENDS],** exist at closing.

Q. WHAT ARE THE PRINCIPAL RISKS THE COMPANY ASSUMES UPON ACQUIRING THE PROJECT FROM RES AMERICAS?

A. The Company will assume all of the contracts that RES Americas has entered into for the Project, including leases, and must conform to the terms of those contracts, which could affect the total capital cost of the Project. The Company will also be responsible for any other capital costs that may arise during our ownership of the project. We believe that we have made reasonable efforts to mitigate these potential risks.

For example, we have performed prudent analysis with respect to interconnection costs and believe that RES Americas' estimate of these costs is reasonably close to the interconnection costs the project is expected to require. We also require that all contracts RES Americas enters into for the project are satisfactory to the Company. We have also confirmed that payments for land rights associated with the project are in the form of ongoing annual lease payments properly treated as O&M expenditures and not capital development costs. Last, we believe that our prudent operation and maintenance of the project will mitigate significant out-year capital contributions.

Q. ARE THE COSTS OF THESE RISKS REFLECTED IN THE PURCHASE PRICE FOR THE

PROJECT?

A. Yes. The purchase price we have negotiated with RES Americas reflects the risks that RES Americas is taking on fully, those risks that they share with the Company, and those risks that the Company will carry. To ensure that the developer delivers the quality of project bargained for, the Company will incur certain oversight costs during development, as well as closing costs associated with the transfer of the project to the company. Our analysis of the project reflects an additional **[TRADE SECRET BEGINS…** …**TRADE SECRET ENDS]** of potential capital costs over-and-above the purchase price to account for our costs and a contingency for risks associated with the cost of transmission.

Q. PLEASE DESCRIBE THE TRANSMISSION INTERCONNECTION RISK.

A. Since the MISO transmission interconnection process is not yet complete, there is some uncertainty around the final interconnection costs for the Courtenay, Odell, and Pleasant Valley projects. However, we believe that such risk has been reasonably mitigated in the agreement for each of these Projects.

Q. WHAT IS THE TRANSMISSION INTERCONNECTION RISK WITH THE COURTENAY PROJECT?

A. The Courtenay Project is presently part of the MISO February 2013 MISO generator interconnection study cycle, which will identify all required transmission upgrades required for the project to interconnect to the transmission grid. The full System Impact Study is not yet complete. However, Geronimo provided the Company the results of the thermal portion

of the Study, which identified the majority of the transmission facility improvements needed for interconnection. The stability portion of the Study has not been completed at this time. Following completion of this System Impact Study, MISO will conduct a Facility Study to determine the costs of the required improvements. Results from the Facility Study will be used to complete the Interconnection Agreement.

We expect the Interconnection Agreement will be completed and executed within the next seven months. While final interconnection costs associated with the Courtenay project will not be fully-known until the System Impact and Facility studies are completed and an Interconnection Agreement is executed, the results known to-date support the Geronimo proposal. Further, as part of the PPA, Geronimo will absorb the generation interconnection cost risks.

The Courtenay project has a unique operation risk associated with transmitting power over transmission lines not owned by a MISO member. Courtenay interconnects to the Ottertail Power Company's Jamestown North Dakota substation. While Ottertail Power is a MISO member, the transmission lines leaving the Jamestown substation are all owned by Minnkota Power Cooperative, which is not a MISO member. There are outstanding disputes over whether the situation requires additional payments to Minnkota. However, we have mitigated the impact of this possibility through the PPA, which requires Geronimo to absorb any such cost risks.

Q. DESCRIBE THE TRANSMISSION INTERCONNECTION RISK WITH THE ODELL

PROJECT.

A. The Odell project is presently part of the MISO August 2012 MISO generator interconnection study cycle, which will identify all required transmission upgrades required for the project to interconnect to the transmission grid. The final System Impact Study has been completed, and the Facility Study to determine the costs of the required improvements are underway. Results from the Facility Study will be used to complete the Interconnection Agreement. We expect the Interconnection Agreement will be completed and executed within the next five months. While final interconnection costs associated with Odell will not be fully-known until the Facility Study is complete and an Interconnection Agreement is executed, the results known to-date support the Geronimo proposal. Geronimo will absorb the generation interconnection cost risks as part of the PPA.

Q. WHAT IS THE TRANSMISSION INTERCONNECTION RISK WITH THE PLEASANT VALLEY PROJECT?

A. The Pleasant Valley Project has applied and will participate in the MISO August 2013 Generator Interconnection Study cycle, which will identify all required transmission upgrades required for the project to interconnect to the transmission grid. Following completion of this System Impact Study, MISO will conduct a Facility Study to determine the improvements that must be made and the costs of such improvements. Results from the Facility Study will be used to complete the Interconnection Agreement. We expect the Interconnection Agreement to be completed and executed within the next 12 months.

Although final interconnection costs associated with the Pleasant Valley Project will not be fully-known until the System Impact and Facility studies are completed and an Interconnection Agreement is executed, RES Americas has obtained an Optional Interconnection Study from MISO that provides support for the **[TRADE SECRET BEGINS… …TRADE SECRET ENDS]** of interconnection costs RES Americas estimated for the Project. This estimated amount is included in the purchase price.

We will be working closely with MISO and RES Americas toward establishing a successful and cost-effective interconnection plan. The parties agree that some risk of additional cost remains since the MISO study process is not yet complete. We have agreed to **[TRADE SECRET BEGINS…**

…TRADE SECRET ENDS]. We believe this reasonably mitigates overly burdensome interconnection cost risk.

In addition, we have contracted with a consultant to "simulate" the MISO generator interconnection System Impact studies to get a better idea of what the Company' exposure is to increased interconnection costs. The results of this simulation support the RES Americas estimate of interconnection costs for the Project. However, because of the fluidity of the MISO interconnection process, we cannot know the magnitude of interconnection costs for certain, and believe it is prudent to include some level of additional cost in the project analysis. In recognition of the additional, yet unidentified, costs Xcel Energy may be responsible for, we have included a contingency of

[TRADE SECRET BEGINS… …TRADE SECRET ENDS] in our estimate of the project's total capital cost.

Q. WHAT ARE THE ENVIRONMENTAL RISKS FOR THE PROJECTS?

A. Under terms of the PPAs for the Courtenay and Odell Projects, Geronimo is responsible for all applicable environmental permits, licenses, and approvals from any governmental authority required under applicable laws for construction, ownership, operation, and maintenance of the facility. The Projects are expected to have minimal impact on avian and bat species, based on significant research that has been performed in the region specific to environmental impacts of wind energy.

Geronimo is developing its Application for a Site Permit for the Odell Project. It expects to file for a site permit from the Minnesota Public Utilities Commission in July 2013, with receipt of the permit anticipated by March 2014.

Geronimo has been surveying the Courtenay Project following the U.S. Fish and Wildlife Service Land-Based Wind Energy Guidelines since Fall 2012. Importantly, the U.S. Fish and Wildlife Service noted that the Project is located outside of the whooping crane migration corridor. The project is also located east of any significant Piping Plover habitat. Geronimo filed its Application for a Site Permit with the Commission in April 2013 (Case. No. PU-13-064), with receipt of the permit anticipated by September 2013.

Q. PLEASE DESCRIBE THE ENVIRONMENTAL RISKS OF THE PLEASANT VALLEY

PROJECT.

A. RES Americas has obtained avian and bat surveys for Pleasant Valley. Based on these surveys, no significant impacts to avian and bat species are expected from the development, construction, commissioning and operation of the Pleasant Valley project. Even so, a requirement of the Site Permit is to develop an avian and bat protection plan to avoid and minimize possible adverse effects to avian and bat species. RES Americas will be working closely with the U.S. Fish and Wildlife Service and other applicable authorities to develop the plan.

Q. WHAT ARE THE POWER PRODUCTION AND CURTAILMENT RISKS FOR THE PROJECTS?

A. The Courtenay and Odell PPAs are designed to compensate Geronimo Energy for the actual electric energy delivered from the wind farms. This provides good incentive for Geronimo to properly maintain their turbines and maximize production. During our due diligence review of these Projects, we identified the risk of curtailment at the Odell site. Under typical PPAs, wind developers are paid by the utility in the event that their project is curtailed. To protect our customers from the costs typically associated with curtailments, we negotiated a provision in the Agreement that specifies that no payments will be made to Geronimo for curtailments or limitations imposed by MISO while the projects have conditional Interconnection Agreements. Additionally, our customers will not pay for curtailments associated with emergencies or transmission system maintenance outages.

If curtailment is high, however, our estimates of long-term benefits could be

affected, if the curtailment results in capacity factors significantly lower than those used in our analysis of the project's benefits. As I mentioned in my discussion of the Strategist analysis of the Projects, we used very conservative estimates of curtailment in our Strategist modeling to assess the potential impacts of curtailment. This resulted in an average curtailment level for the Projects of over 10 percent over the course of the first ten years of the Projects' lives – which is significantly more conservative than the actual 1.4 percent occurring over the recent 12 month period from May 2012 through April 2013. For this reason, we believe our estimates of long-term benefits are appropriately conservative.

Q. WHAT ARE THE OPERATIONAL RISKS OF THE PLEASANT VALLEY PROJECT?

A. Because the Company owns it, the operational risks associated with Pleasant Valley remain with the Company. However these risks are offset by the higher estimated benefits that flow from Company ownership. To the extent that annual generation at Pleasant Valley is lower than expected, we would lose energy at no significant change in cost, and the overall cost-effectiveness of the Project would decrease. Conversely, if annual generation is greater than expected, the customer benefits from the Project would increase. Owned projects also have some uncertainty in annual costs for operation and maintenance.

In each of these areas, we have included in our project evaluation conservative estimates of the expected on-going costs at Pleasant Valley. As noted previously, curtailment estimates are an order of magnitude higher than have been recently experienced. Capacity factor assumptions are lower than the

vendor relied-on, and sensitivity tests with even lower capacity factors still identify substantial cost savings can be had for customers. I discuss both of these potential operating risks in my testimony regarding the Strategist analysis of the projects.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

STATE OF NORTH DAKOTA
BEFORE THE
NORTH DAKOTA PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF NORTHERN STATES POWER COMPANY FOR AN ADVANCE DETERMINATION OF PRUDENCE FOR A 200 MW POWER PURCHASE AGREEMENT WITH THE COURTENAY WIND PROJECT	**Case No. PU-13-_____**
IN THE MATTER OF THE APPLICATION OF NORTHERN STATES POWER COMPANY FOR AN ADVANCE DETERMINATION OF PRUDENCE FOR A 200 MW POWER PURCHASE AGREEMENT WITH THE ODELL WIND PROJECT	**Case No. PU-13-_____**
IN THE MATTER OF THE APPLICATION OF NORTHERN STATES POWER COMPANY FOR AN ADVANCE DETERMINATION OF PRUDENCE FOR THE 200 MW PLEASANT VALLEY WIND PROJECT	**Case No. PU-13-_____**

VERIFICATION

STATE OF MINNESOTA)
) ss.
COUNTY OF HENNEPIN)

Steven W. Wishart, being first duly sworn on oath, deposes and says that he is 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 matters, that the testimony and schedules submitted in the above captioned

matters 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.

Steven W. Wishart

Subscribed and sworn to before me this 23rd day of July, 2013.

Notary Public
My Commission Expires: 3/30/15

EDNA G. MATHEIS NOTARY PUBLIC STATE OF COLORADO MY COMMISSION EXPIRES MARCH 30, 2015

Steven W. Wishart Jr.

(612) 508-0869
Steve@Wishart.com
1814 Kohinoor Pl.
Golden CO, 80401

EXPERIENCE

Xcel Energy, Minneapolis MN, Denver CO 5/12-Current
Director – Resource Planning & Bidding

Xcel Energy, Minneapolis MN, Denver CO 4/06-05/12
Manager / Sr. Analyst / Analyst – Strategic Analytics

Responsibilities:

- Oversee economic evaluation of large power supply projects for Xcel Energy.
- Prepare analysis for senior leadership that reports on expected value and value at risk for new generation assets, power purchases, conservation programs, wholesale sales, and other projects.
- Maintain complex model of the three Xcel Energy power systems for use in, project evaluation, rate forecasting, and policy analysis.
- Manage a group of quantitative analysts that evaluate various supply and demand side alternatives for all three Xcel Energy service territories.
- Serve as quantitative expert for resource planning and purchased power related dockets.

Major Projects:

- Colorado Clean Air Clean Jobs Act – Retire/repower 900MW of existing coal units in PSCo service territory for compliance with regional NOx legislation.
- 2010 Minnesota Resource Plan – 10 year projection of new resource acquisitions, retirements, renewable energy standard compliance, and enhanced conservation programs.
- Jones Station Repowering – Convert existing 240MW gas steam unit to 650MW combined cycle in SPS service territory.
- 2009 PSCo All-Source Solicitation – Modeling/evaluation of bids totaling 20,000MW. Including Gas, wind, solar PV, solar thermal with storage, compressed air storage, pumped hydro, wind/battery combo, and solar augmented combined cycle.
- Manitoba Hydro CON – Economic valuation of 10yr $1.6B purchase from MH.
- Nuclear Uprate Projects – Economic evaluation and expert witness for Prairie Island and Monticello nuclear uprate proceeding in NSP service territory.
- CO2 Regulation - Forecasted rate impacts of American Clean Energy and Security Act (ACES) on the Xcel Energy operating companies.
- Other - Bottom up redesign of Xcel's long-range planning models, focusing on consistency across jurisdictional operating companies and integration of best practices including Monte-Carlo simulation for risk evaluation. Represented Xcel Energy at MISO board of directors/stakeholder meetings on the topic of wind integration. Long range rate forecasts for management and stakeholders. Financial and economic analysis for Excelsior IGCC project. Analysis of long term power purchase from Manitoba Hydro. EEI regulatory accounting seminar.

Software:

- Strategist, Matlab, Prosym, Excel, Access.

Xcel Energy, Minneapolis MN
Demand Side Management (DSM) Technical Analyst 2/05-4/06

Responsibilities:

- Managed cost/benefit analysis of NSP's $45 million annual conservation and load management activities, including forecasting of financial incentives, and strategic planning.

Projects:

- Evaluation and contract negotiations of DSM bids in Colorado service territory.
- Conservation rulemaking in New Mexico, including design of financial incentive mechanism.
- Cost benefit analysis of NSP's three-year conservation and load management strategic plan.

Software:

- Strategist, DSManager, Matlab, Excel.

The Solar Store, Tucson AZ 10/98-8/00
Accountant

- AR/AP, payroll, inventory management, sales, solar energy system design & installation.
- Member of Concerned Arizonans for Renewable Energy (CARE) lobbied in support of solar tax credits in Arizona.

EDUCATION

PhD (all but dissertation) **Applied Economics, University of Minnesota, 3.7GPA** 8/02-1/05

Course Work:

- Emphasis - environmental and natural resource economics. Other course work - Financial economics, econometrics, dynamic programming, production economics, non-parametric frontier analysis, managerial economics, international trade, macro- and microeconomics.

Software:

- SAS, Matlab, Gauss, Stata, Mathematica.

MS Economics, University of Arizona, 3.8GPA 8/00-5/02

Course Work:

- Environmental economics, environmental law, econometrics, linear and quadratic programming, production economics, consumer economics.

Software:

- SAS, Stata, LimDep, Gams, Lindo, Gauss.

BS Finance, University of Arizona 8/92-12/96

Course Work:

- Financial markets and instruments, corporate finance, accounting, statistics, economics, marketing, Russian, French.