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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\_\_\_\_\_  
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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

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**I. INTRODUCTION**

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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;

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- 1       • The Company’s analysis of the bids received through the RFP  
2       process, which narrowed the field to the three 200 MW resources we  
3       propose to add to our system;
- 4       • A description of the proposed resource additions:
  - 5           ○ A PPA with Geronimo Energy for the 200 MW Courtenay wind  
6           project in Stutsman County, North Dakota;
  - 7           ○ A PPA with Geronimo for the Odell wind project located near  
8           Mountain Lake, Minnesota; and
  - 9           ○ The 200 MW Pleasant Valley wind project being developed by  
10          RES Americas near our Grand Meadow Wind Farm in  
11          southeastern Minnesota, which, upon completion, RES Americas  
12          will transfer to the Company; and
- 13      • The effects of our proposed resource addition on the Company’s  
14      pending peaking plan proposal in Case Nos. PU-13-194 and PU-13-  
15      195.

16  
17      I conclude my testimony with a discussion of the development and  
18      operational risks that the Company identified for these Projects, and the steps  
19      we have taken to mitigate those risks.

20  
21                   **II. REQUEST FOR PROPOSAL PROCESS**

22  
23    Q.   WHAT PROMPTED THE COMPANY TO ISSUE AN RFP FOR WIND GENERATION?

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

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1  
2 Our 2011-2025 Resource Plan identified the need for additional wind  
3 resources, if these resources were competitively-priced relative to traditional  
4 generation. Part of our strategic plan was to monitor the market for wind  
5 energy and pursue new resources when it appeared they were likely to be cost  
6 effective. When the January 2013 federal legislation extended the Production  
7 Tax Credit to projects that begin construction activities by the end of 2013, we  
8 believed there may be opportunities to secure additional wind resources for  
9 our integrated system at cost-effective prices, since the PTC can account for a  
10 substantial portion of a wind project's total cost.

11  
12 Q. PLEASE DESCRIBE THE COMPANY'S RFP PROCESS.

13 A. We issued the RFP on February 18, 2013, and notified national and regional  
14 media and trade press. In the notification, we provided a link to our website  
15 where the RFP, model Power Purchase Agreement, and standard bidder  
16 forms were located.<sup>1</sup>

17  
18 The RFP was open to proposals of any size up to 200 MW and of various  
19 structures including utility ownership, PPA or any combination thereof with  
20 no preference given to any particular type of structure. Bidders were  
21 encouraged to e-mail questions or call the designated point of contact for the  
22 RFP prior to the submission of their proposals. The RFP outlined the  
23 submittal requirements including completion of standard bidder forms  
24 designed to ensure adequate and consistent collection of information from

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<sup>1</sup> These documents are available at [http://www.xcelenergy.com/About Us/Our Company/Projects and RFPs/2013 Upper Midwest Wind Power Request for Proposals](http://www.xcelenergy.com/About%20Us/Our%20Company/Projects%20and%20RFPs/2013%20Upper%20Midwest%20Wind%20Power%20Request%20for%20Proposals)

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

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

11  
12 Q. WHAT WAS THE REPOSENSE TO THE RFP?

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

18  
19 **III. COMPANY ANALYSIS OF PROPOSALS**

20  
21 Q. HOW DID THE COMPANY ANALYZE THE PROPOSALS?

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

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

6  
7 The initial screening process allowed us to identify the most cost-effective  
8 projects so we could focus our efforts on those having the best potential to  
9 provide long-term value to our customers. Based on the distribution of  
10 levelized cost we narrowed our review to bids that were at or below  
11 \$29/MWh. We chose the cutoff price of \$29/MWh, as it provided for a  
12 reasonable number of the most cost-effective proposals from which to focus  
13 further review efforts. There were 14 projects within the established levelized  
14 price threshold area.

15  
16 Q. WHAT WERE THE NEXT STEPS TO FURTHER NARROW THIS FIELD OF PROPOSED  
17 PROJECTS?

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

26

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

5

6 Q. HOW WAS THE PLEASANT VALLEY PROJECT SELECTED?

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

12

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

19

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

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

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1 costs, environmental risk, developer experience and several other criteria. The  
2 process resulted in the Company entering into agreements for the Courtenay,  
3 Odell, and Pleasant Valley projects.  
4

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

7 A. Yes. We engaged an independent auditor to examine whether the process for  
8 obtaining and evaluating responses to the RFP was biased. The independent  
9 auditor's report, included as Exhibit\_\_\_\_(SWW-1), Schedule 3 to my testimony,  
10 concluded that the Company's RFP process was free from bias, and afforded  
11 each proposal equitable care and consideration. In addition, the report noted  
12 that the process was rigorous, robust and consistent – and that the Company  
13 administered the process professionally and was thorough in its efforts.  
14

15 **IV. PROJECT DESCRIPTIONS**  
16

17 Q. PLEASE DESCRIBE THE COURTENAY PROJECT.

18 A. The Courtenay Project is a 200 MW wind energy generation facility. It is  
19 located along the edge of the Missouri Coteau in east-central North Dakota,  
20 northeast of Jamestown. We have entered into a 20-year PPA with Geronimo  
21 Energy to purchase all of the electric energy produced at Courtenay.  
22

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

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

3  
4 The Courtenay project will interconnect to the Otter Tail Power 345/115kV  
5 substation located north of Jamestown, North Dakota. The project is in the  
6 February 2013 Definitive Planning Phase of the MISO Generator  
7 Interconnection Process.

8  
9 Q. WHAT IS THE COURTENAY PROJECT'S CONSTRUCTION SCHEDULE?

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

16  
17 Q. WHAT ARE THE TERMS OF THE COURTENAY PPA?

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

23  
24 The purchase price of electric energy from Courtenay starts at [**TRADE**  
25 **SECRET BEGINS...**

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

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1 over the term of the agreement to be [TRADE SECRET BEGINS...  
2 ...TRADE SECRET ENDS].

3  
4 Q. PLEASE DESCRIBE THE ODELL PROJECT.

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

11  
12 The project will consist of up to 124 wind turbine generators and associated  
13 infrastructure. Associated infrastructure includes access roads, electrical  
14 collection system, meteorological monitoring stations, a project collector  
15 substation, a transmission line, a new interconnection substation, and an  
16 operations and maintenance facility.

17  
18 The Odell project will interconnect at a new 345/115 kV substation on the  
19 Lakefield Generation – Fieldon segment of Northern States Power's Lakefield  
20 Junction – Wilmarth 345 kV transmission line. Odell is part of the August  
21 2012 Definitive Planning Phase of the MISO Generator Interconnection  
22 Process.

23  
24 Q. WHAT IS THE ODELL PROJECT'S CONSTRUCTION SCHEDULE?

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

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1 will occur in 2013. Under terms of the Agreement, commercial operation  
2 shall occur no sooner than November 30, 2014 and no later than December  
3 31, 2015. This schedule is designed such that the project will qualify for the  
4 federal PTC, which will provide cost benefits to our customers.

5  
6 Q. WHAT ARE THE TERMS OF THE ODELL PPA?

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

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

16  
17 Q. PLEASE DESCRIBE THE PLEASANT VALLEY PROJECT.

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

24  
25 The Pleasant Valley project will consist of **[TRADE SECRET BEGINS...**

26 **...TRADE SECRET ENDS]** wind turbine generators

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

8  
9 The Pleasant Valley project will interconnect to Great River Energy's 345/161  
10 kV Pleasant Valley substation. The project has applied and will participate in  
11 the MISO August 2013 Generator Interconnection Study cycle, which will  
12 identify all required transmission upgrades required for the project to  
13 interconnect to the transmission grid.

14  
15 Q. WHAT IS THE PROJECT'S CONSTRUCTION SCHEDULE?

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

21  
22 Q. PLEASE DESCRIBE HOW XCEL ENERGY WILL ACQUIRE THE PLEASANT VALLEY  
23 PROJECT FROM RES AMERICAS.

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

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

3  
4 We have agreed to structure the transaction as a purchase of an LLC to allow  
5 RES Americas some flexibility in development of the Project, to create  
6 efficiencies in the mechanics of the Project transfer by taking advantage of  
7 certain legal merger constructs, and to provide certain tax benefits during  
8 development. This structure requires RES Americas to assume construction  
9 risk throughout the development and construction phase of the Project, as  
10 they are responsible for the physical construction of the Project.

11  
12 After the closing of the purchase, the Company will dissolve the LLC and  
13 reflect the Project assets on its books as if Pleasant Valley were any other  
14 Company owned generating facility. While the Company has not engaged in  
15 any transactions structured in this way in the past, our affiliate, Public Service  
16 Company of Colorado, has recently and successfully consummated such a  
17 transaction.

18  
19 Q. WHAT ARE THE TERMS OF THE PSA?

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

25  
26 Q. WHAT ARE THE COSTS OF THE PLEASANT VALLEY PROJECT?

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1 A. We estimate the total capital cost of Pleasant Valley will be approximately  
2 **[TRADE SECRET BEGINS... ...TRADE SECRET**  
3 **ENDS]**, including Xcel Energy’s anticipated development oversight and  
4 ownership transfer closing costs. Our PSA with RES Americas calls for  
5 payments of approximately **[TRADE SECRET BEGINS...**  
6 **...TRADE SECRET ENDS]** for development of the project. We estimate  
7 Xcel Energy’s development oversight and ownership transfer costs will be up  
8 to \$4 million. We have included an additional **[TRADE SECRET**  
9 **BEGINS... ...TRADE SECRET ENDS]** in our capital estimate  
10 and project analysis to cover the risk of additional transmission  
11 interconnection costs the Company may be responsible for. We calculate the  
12 25-year, levelized cost of electricity to be **[TRADE SECRET BEGINS...**  
13 **...TRADE SECRET ENDS]**, based on all capital costs and our estimates of  
14 O&M.

**V. STRATEGIST ANALYSIS OF PROJECTS**

17  
18 Q. HOW DID THE COMPANY EVALUATE THE COST-EFFECTIVENESS OF THE  
19 PROJECTS?

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

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

3  
4 Q. WHAT ASSUMPTIONS DID THE COMPANY MAKE IN ITS EVALUATION TO  
5 INCREASE THE CONFIDENCE LEVELS OF ITS MODELING RESULTS?

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

13  
14 Wind generation produces financial benefits by reducing the costs of both  
15 fossil fuel generation and purchased energy from the market. When wind  
16 resources are producing energy, generation from conventional resources such as  
17 natural gas plants can be reduced without impacting the reliability of service to  
18 our customers. The energy from our proposed 600 MW wind portfolio is  
19 expected to avoid the purchase of over 170 billion cubic feet of natural gas  
20 over their contract and service lives, as well as avoid the purchase of almost  
21 13,000 gigawatt hours of energy. The Strategist analysis accounts for these  
22 cost savings, as well as the impact of the capital commitments or PPA  
23 payments associated with the wind generation additions.

24  
25 Q. WHAT WERE THE COST BENEFITS OF THE PROJECTS AS QUANTIFIED BY THE  
26 STRATEGIST ANALYSIS?

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

8

**Table 1: Net PVRR Impact (Savings)**

<b>PVRR (\$ millions)</b>	<b>Reference Case</b> <i>(\$0/ton CO<sub>2</sub>)</i>	<b>Low Gas</b> <i>(1.7% growth rate)</i>
Pleasant Valley 200MW	(\$90)	(\$17)
Odell 200MW	(\$53)	(\$1)
Courtenay 200MW	(\$60)	(\$10)
Portfolio 600MW	(\$184)	(\$14)

9

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

13

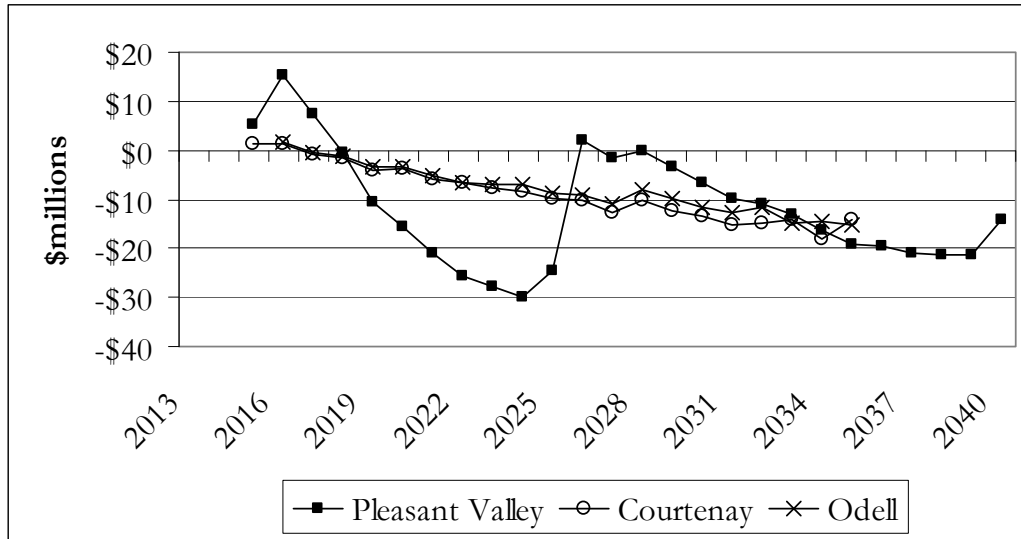
14 Q. HOW ARE THESE COST SAVINGS SPREAD OVER TIME?

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

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**Figure 1: Annual Net Costs (Savings)**



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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.

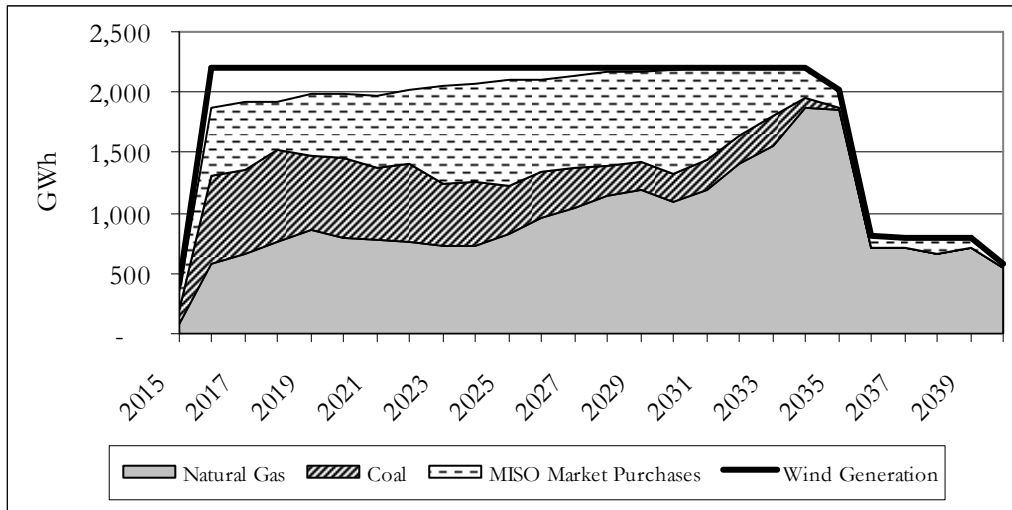
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Q. WHAT WILL THE ANNUAL IMPACTS BE ON THE NSP SYSTEM?

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**



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13  
14  
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17

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

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

4  
5 From 2015 through 2025, this accounts for more than ten percent of the total  
6 energy produced by the three projects. This is a very conservative estimate of  
7 curtailment, and is a result of how the MISO market is modeled in Strategist.  
8 Currently, less than 1.4 percent of wind is actually curtailed on the NSP  
9 System. Having the conservative 10+ percent estimate of curtailment built  
10 into our model ensures that the net benefits to our customers are not being  
11 overstated, and that the realized customer bill reductions may actually be  
12 larger than forecasted.

13  
14 Q. WHAT OTHER BENEFITS DO THE 600 MW OF WIND PROVIDE?

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

20  
21 Strategist simulations indicate that the additional 600 MW of wind will avoid  
22 the need for seven bcf of natural gas and over 600 GWh of MISO market  
23 purchases annually; over the lifetime of the projects, a total of 176 bcf of  
24 natural gas and over 13,000 GWh will be displaced.

25  
26 Likewise these resources will create a hedge against potential federal CO2

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

7  
8 To illustrate the benefit of these projects, Table 2 below shows the base case  
9 volumes of natural gas, market purchases and CO2 emissions – and the deltas  
10 against these factors for the studied projects.

11  
**Table 2: Hedge Value**

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

12 Q. WHAT IS THE ESTIMATED RATE IMPACT ON THE COMPANY'S NORTH DAKOTA  
13 CUSTOMERS?

14 A. We expect that soon after initial operation, customers' overall bills will be  
15 lower as a result of the proposed wind projects. Our Strategist analysis  
16 forecasts that the cost of Pleasant Valley and the PPA projects will be more  
17 than offset by decreases in the cost of fossil fuel and other purchased energy.

18  
19 While the 600 MW of wind resources represents the largest individual

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1 renewable energy acquisition we have made, the relative impacts are small due  
 2 the large size of the NSP System. Table 3 below provides estimates of how  
 3 average rates will be impacted by the proposed projects. Over the first four  
 4 years, the average impact on a typical residential bill would be a monthly  
 5 *increase* of 18 cents. Over the next seven years (2019-2025), our models  
 6 forecast an average *decrease* of 51 cents per month, resulting in a net decrease  
 7 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	<b>0.01¢/kWh</b>	<b>0.05¢/kWh</b>	<b>0.02¢/kWh</b>	<b>0.00¢/kWh</b>	<b>(0.03¢/kWh)</b>	<b>(0.05¢/kWh)</b>

	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	<b>(0.06¢/kWh)</b>	<b>(0.07¢/kWh)</b>	<b>(0.08¢/kWh)</b>	<b>(0.09¢/kWh)</b>	<b>(0.08¢/kWh)</b>

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

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

14  
 15 The cost for Courtenay and Odell are modeled as simple \$/MWh cost rates  
 16 that adjust once per year to account for the fixed price escalations specified in

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

3  
4 For Company-owned projects, the upfront purchase price needs to be  
5 translated into a projection of annual revenue requirement associated with  
6 financing, operations, depreciation, and taxes. Projections of upfront and on-  
7 going capital investments and annual operating and maintenance expenses also  
8 need to be developed. To test how variations from the capital expenditures  
9 and O&M would impact the overall cost-effectiveness of the projects, we  
10 conducted sensitivity tests in Strategist of plus and minus 25 percent of  
11 projected on-going capital investments and O&M expenses.

12  
13 The economic benefit of an owned-wind project is highly-dependent on the  
14 annual generation from the site. Each additional MWh produced by a  
15 Company-owned project increases the value of the project because the higher  
16 the production, the lower the average costs will be, and therefore, the larger  
17 the benefits. To test how average capacity factors impact the economic value  
18 of Pleasant Valley performed Strategist sensitivity using +/- 5 percent of the  
19 expected annual generation. The base assumption for the life of each  
20 ownership option was 25 years, and sensitivities were performed for 20-year  
21 and 30-year lives.

22  
23 Q. PLEASE DESCRIBE THE OTHER PRINCIPAL ELEMENTS OF THE MODELING.

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

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1 transmission congestion and line losses for new resources.

2  
3 The TWY profiles were adjusted to match the target annual generation. The  
4 Strategist model also included an additional wind integration cost to account  
5 for incremental operating reserves that may be required to support the  
6 intermittent nature of the projects. The levelized cost of the wind integration  
7 was \$3.62/MWh, equivalent to over \$7 million annual.

8  
9 In accordance with the latest MISO ELCC analysis, we modeled Courtenay  
10 and Odell as having a 13.3 percent accredited capacity value. However, per  
11 MISO's tariff and business practices, in order to receive accreditation as a  
12 capacity resource, it must have firm delivery rights either with Network  
13 Resource Interconnection Service or firm transmission service (Network  
14 Integration Transmission Service or Firm Point-to-Point Transmission  
15 Service). Our expectation is that these resources will not be given this  
16 designation until 2021 when various transmission system upgrades, including  
17 MISO's MVP projects, are complete. Our modeling efforts reflect the  
18 expected capacity accreditation in 2021.

19  
20 The Strategist model does not explicitly model transmission congestion and  
21 line losses for new resources. To ensure that we are accounting for all the  
22 costs associated with our wind proposal, we included the congestion and line  
23 loss estimates from MISO's 2012 Promod model. The Promod model  
24 contains detailed information on the transmission topology in MISO, and has  
25 the ability to forecast hourly prices at individual nodes throughout the system.  
26 It is the same model that MISO used in their most recent round of

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

5  
 6 Q. WHAT WERE THE RESULTS OF THE STRATEGIST MODELING?

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

**Table 4: PVRR Results (\$millions)**

			30 Year	20 Year	+5%	-5%	+25%	-25%
			Operating	Operating	Capacity	Capacity	On-Going	On-Going
			Life	Life	Factor	Factor	Ownership	Ownership
	Base	Low Gas	Life	Life	Factor	Factor	Costs	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)**

			30 Year	20 Year	+5%	-5%	+25%	-25%
			Operating	Operating	Capacity	Capacity	On-Going	On-Going
			Life	Life	Factor	Factor	Ownership	Ownership
	Base	Low Gas	Life	Life	Factor	Factor	Costs	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)

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

4  
5 Q. DID THE COMPANY CALCULATE THE STRATEGIST RESULTS IN TERMS OF  
6 LEVELIZED COST?

7 A. Yes. Levelized prices are a fixed \$/MWh price that have the same NPV as the  
8 actual cost streams generated by Strategist. I have found that putting the  
9 Strategist results in terms of \$/MWh is more intuitive and leads to better  
10 understanding of the analysis. As mentioned previously, in addition to the  
11 direct project costs, the Strategist model also adds cost for wind integration,  
12 transmission congestion, and line losses. The primary benefit of the projects  
13 is displaced generation from fossil fuel resources, but the model also tracks  
14 capacity credits based on the cost of natural gas combustion turbines. Table 6  
15 below illustrates how the levelized costs of the agreements are more than  
16 offset by the value of avoided generation.

**Table 6: Levelized Costs Analysis - \$/MWh**

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

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**VI. IMPACT ON CAPACITY NEED**

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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

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

5  
6 Q. WHAT RISKS DID THE COMPANY IDENTIFY?

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

12  
13 Q. PLEASE DESCRIBE THE FEDERAL PTC RISK.

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

20  
21 We believe these projects will meet the requirements necessary to qualify for  
22 the PTC, and that the risk has been reasonably mitigated in the relevant  
23 agreements. As it relates to the Courtenay and Odell Projects, Geronimo  
24 assumes the risk of qualifying for the PTC if the Projects are unable to meet  
25 the requirements. Under the PSA for the Pleasant Valley Project, RES  
26 Americas is required to **[TRADE SECRET BEGINS...**

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...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

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1 for the completion of certain punch list items after the closing, as well as an  
2 additional holdback amount in the event that curable breaches, not to exceed

3 **[TRADE SECRET BEGINS... ..TRADE**  
4 **SECRET ENDS]**, exist at closing.

5  
6 Q. WHAT ARE THE PRINCIPAL RISKS THE COMPANY ASSUMES UPON ACQUIRING  
7 THE PROJECT FROM RES AMERICAS?

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

14  
15 For example, we have performed prudent analysis with respect to  
16 interconnection costs and believe that RES Americas' estimate of these costs  
17 is reasonably close to the interconnection costs the project is expected to  
18 require. We also require that all contracts RES Americas enters into for the  
19 project are satisfactory to the Company. We have also confirmed that  
20 payments for land rights associated with the project are in the form of  
21 ongoing annual lease payments properly treated as O&M expenditures and not  
22 capital development costs. Last, we believe that our prudent operation and  
23 maintenance of the project will mitigate significant out-year capital  
24 contributions.

25  
26 Q. ARE THE COSTS OF THESE RISKS REFLECTED IN THE PURCHASE PRICE FOR THE

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1 PROJECT?

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

12

13 Q. PLEASE DESCRIBE THE TRANSMISSION INTERCONNECTION RISK.

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

19

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

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

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

7  
8 We expect the Interconnection Agreement will be completed and executed  
9 within the next seven months. While final interconnection costs associated  
10 with the Courtenay project will not be fully-known until the System Impact  
11 and Facility studies are completed and an Interconnection Agreement is  
12 executed, the results known to-date support the Geronimo proposal. Further,  
13 as part of the PPA, Geronimo will absorb the generation interconnection cost  
14 risks.

15  
16 The Courtenay project has a unique operation risk associated with  
17 transmitting power over transmission lines not owned by a MISO member.  
18 Courtenay interconnects to the Ottertail Power Company's Jamestown North  
19 Dakota substation. While Ottertail Power is a MISO member, the  
20 transmission lines leaving the Jamestown substation are all owned by  
21 Minnkota Power Cooperative, which is not a MISO member. There are  
22 outstanding disputes over whether the situation requires additional payments  
23 to Minnkota. However, we have mitigated the impact of this possibility  
24 through the PPA, which requires Geronimo to absorb any such cost risks.

25  
26 Q. DESCRIBE THE TRANSMISSION INTERCONNECTION RISK WITH THE ODELL

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1 PROJECT.

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

14

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

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

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

8  
9 We will be working closely with MISO and RES Americas toward establishing  
10 a successful and cost-effective interconnection plan. The parties agree that  
11 some risk of additional cost remains since the MISO study process is not yet  
12 complete. We have agreed to **[TRADE SECRET BEGINS...**

13  
14  
15 **...TRADE SECRET ENDS]**. We believe this  
16 reasonably mitigates overly burdensome interconnection cost risk.

17  
18 In addition, we have contracted with a consultant to “simulate” the MISO  
19 generator interconnection System Impact studies to get a better idea of what  
20 the Company’ exposure is to increased interconnection costs. The results of  
21 this simulation support the RES Americas estimate of interconnection costs  
22 for the Project. However, because of the fluidity of the MISO  
23 interconnection process, we cannot know the magnitude of interconnection  
24 costs for certain, and believe it is prudent to include some level of additional  
25 cost in the project analysis. In recognition of the additional, yet unidentified,  
26 costs Xcel Energy may be responsible for, we have included a contingency of

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

3  
4       Q.   WHAT ARE THE ENVIRONMENTAL RISKS FOR THE PROJECTS?

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

12  
13      Geronimo is developing its Application for a Site Permit for the Odell Project.  
14      It expects to file for a site permit from the Minnesota Public Utilities  
15      Commission in July 2013, with receipt of the permit anticipated by March  
16      2014.

17  
18      Geronimo has been surveying the Courtenay Project following the U.S. Fish  
19      and Wildlife Service Land-Based Wind Energy Guidelines since Fall 2012.  
20      Importantly, the U.S. Fish and Wildlife Service noted that the Project is  
21      located outside of the whooping crane migration corridor. The project is also  
22      located east of any significant Piping Plover habitat. Geronimo filed its  
23      Application for a Site Permit with the Commission in April 2013 (Case. No.  
24      PU-13-064), with receipt of the permit anticipated by September 2013.

25  
26      Q.   PLEASE DESCRIBE THE ENVIRONMENTAL RISKS OF THE PLEASANT VALLEY

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1 PROJECT.

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

10

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

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

25

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

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

11  
12 Q. WHAT ARE THE OPERATIONAL RISKS OF THE PLEASANT VALLEY PROJECT?

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

22  
23 In each of these areas, we have included in our project evaluation conservative  
24 estimates of the expected on-going costs at Pleasant Valley. As noted  
25 previously, curtailment estimates are an order of magnitude higher than have  
26 been recently experienced. Capacity factor assumptions are lower than the

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


5

6 Q. DOES THIS CONCLUDE YOUR TESTIMONY?

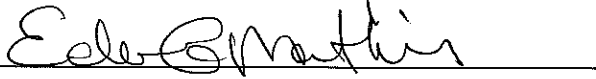
7 A. Yes, it does.

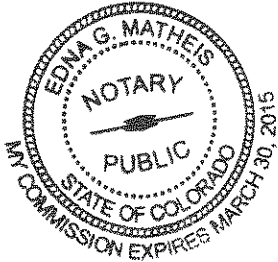


matters under his name were prepared under his direction, that he knows the contents thereof, and that the same is true and correct to the best of his knowledge and belief.

  
\_\_\_\_\_  
Steven W. Wishart

Subscribed and sworn to before me this 23<sup>rd</sup> day of July, 2013.

  
\_\_\_\_\_  
Notary Public  
My Commission Expires: 3/30/15



**Steven W. Wishart Jr.**

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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.