BEFORE THE

PUBLIC SERVICE COMMISSION OF THE STATE OF NORTH DAKOTA

IN THE MATTER OF THE APPLICATION OF NORTHERN STATES POWER COMPANY, A MINNESOTA CORPORATION, FOR ADVANCE DETERMINATION OF PRUDENCE FOR A POWER PURCHASE AGREEMENT WITH GERONIMO WIND ENERGY, LLC)	DOCKET NO. PU-12-059

PUBLIC REDACTED VERSION

INITIAL TESTIMONY

OF

RICHARD S. HAHN

ON BEHALF OF

THE NORTH DAKOTA PUBLIC SERVICE COMMISSION

ADVOCACY STAFF

EXHIBIT

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AUGUST 31, 2012

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INITIAL TESTIMONY

OF

RICHARD S. HAHN

I. QUALIFICATIONS

Q. Please state your name, position, and business address.

A. My name is Richard S. Hahn. I am employed by La Capra Associates, Inc. ("La Capra") as a Principal Consultant. My business address is One Washington Mall, 9th Floor, Boston, Massachusetts 02108.

Q. Please summarize your professional experience and qualifications.

A. I received my Bachelor's in Science, Electrical Engineering, in 1973, and my Masters in Science, Electrical Engineering, in 1974, both from Northeastern University. I received my Masters in Business Administration from Boston College in 1982. Since joining La Capra, I have worked on many projects related to energy markets, forecasts of wholesale market prices, utility resource planning projects, and asset valuations. Prior to joining La Capra, I worked at NSTAR Electric & Gas (formerly Boston Edison Company) from 1973 to 2003. Throughout my career, I have gained and demonstrated considerable experience and expertise in utility planning activities. I am a registered professional electrical engineer in the Commonwealth of Massachusetts. My resume is provided in Exhibit RSH-1.

Q. Have you previously testified before this Commission?

A. Yes. I previously testified in Docket No. PU-11-165, the proceeding to review the joint request by Otter Tail Power and Montana Dakota Utilities for an Advanced Determination of Prudence to install the Big Stone Air Quality Control system, and in Dockets Nos. PU-11-395 PU-11-396, the proceedings to review the requests by Montana Dakota Utilities for an Advanced Determination of Prudence and a Certificate of Public Convenience and Necessity to construct a new gas-fired combustion turbine generating unit.

Q. Please summarize La Capra Associates and its business.

A. La Capra Associates provides consulting services in energy planning, market analysis, and regulatory policy in the electricity and natural gas industries. We serve a national and international clientele from our offices in Boston, Massachusetts, Portland, Maine, and Williston, Vermont providing consulting services to a broad range of organizations involved with energy markets, including renewable energy producers, private and public utilities, energy producers and traders, energy consumers and consumer advocates, regulatory agencies, and public policy and energy research organizations. Our technical skills include power market forecasting models and methods, economics, management, planning, rates and pricing, and energy procurement, and contracting. Our experience includes detailed analyses of energy and environmental performance of the electric systems, economic planning for transmission, and market analytics.

II. PURPOSE OF TESTIMONY

Q. On whose behalf are you appearing in these proceedings?

A. I am testifying on behalf of the North Dakota Public Service Commission Advocacy Staff ("Advocacy Staff").

Q. Please describe the purpose of your testimony.

A. La Capra has been retained by the Advocacy Staff to assist in reviewing the application of Northern States Power ("NSP" or "The Company") for an Advance Determination of Prudence ("ADP") related to its proposed Power Purchase Agreement ("PPA") to purchase 200 MW of electric energy from Geronimo Wind Energy, LLC generated at the Prairie Rose Wind Project located in Minnesota. Specifically, we were asked to provide a detailed analysis and conclusion related to the necessity and economic prudence of the PPA. Our assessment methodology was to utilize the discovery process to obtain a detailed understanding of NSP's filing and the underlying assumptions, inputs and analyses.

III. SUMMARY OF TESTIMONY

Q. Please summarize your conclusions and recommendations.

A. Based upon my review of NSP's Application, I conclude that because this project is not needed and is more costly than other alternatives. On a present value basis, the PPA will cost $41 million to $64 million more than other resources. Therefore, the proposed PPA is not in the public interest. I recommend that the requested ADP not be granted.

IV. OVERVIEW OF THE APPLICATION

Q. Please summarize NSP's Application.

A. NSP has filed an application for an Advance Determination of Prudence for a Power Purchase Agreement with Geronimo Wind Energy for the output of the 200 MW Prairie Rose Wind project ("PRW" or the "Project"). According to the Company, the PPA is a "prudent and cost-effective opportunity to achieve a portion of our future energy supply requirements."[1] The Project will enter service by the end of 2012 and is located in Rock and Pipestone Counties, Minnesota. The project will connect with the grid at the interconnection point of Xcel's Angus Anson peaking plant using Net Zero Interconnection Service.

The Company's Application contains discussion of the following issues:

- Request for Proposal Process: The Application discusses the 2012 RFP process, an overview of the responses, and the justification for selection of the Prairie Rose project.
- Description of the PPA: The PPA covers the entire output of the Project for a 20-year term. The PPA energy price begins at **[TRADE SECRET BEGINS** ______________________________ ______________________________ **TRADE SECRET ENDS]**.[2] The PPA also allows the use of a provisional interconnection agreement using Net Zero Interconnection Service ("NZIS"). MISO tariff revisions allowing the use of NZIS are currently under consideration at

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[1] Application, p. 1.
[2] Application, pp. 8-9.

FERC and the Prairie Rose project has not yet received a permanent interconnection agreement.

- <u>Reasonableness of the PPA</u>: The Application presents two economic analyses – a comparison of the PPA to a natural gas generation alternative and an analysis using the Strategist resource planning model – to support the reasonableness of the project. The Application also discusses how the project will help the Company achieve its requirements and goals under out-of-state Renewable Energy Standards ("RES") and North Dakota's Renewable Energy Objective ("REO").
- <u>Other Agreement</u>: The application also contains a contract entitled "DEVELOPMENT AND PURCHASE OPTION AGREEMENT AND SEPARATE OPTION TO PURCHASE TRANSMISSION LINE" which provides the Company with options to (a) acquire the transmission line being constructed by PRW to interconnect to the MISO system, and (b) acquire additional wind generation assets that may be constructed at the PRW site. It is my understanding that the Company is not seeking any approvals relative to this agreement. If any of the options available to NSP pursuant to this agreement are exercised, the Company will seek any additional required approvals at that future time.

V. STANDARD OF REVIEW

Q. What approval is the Company seeking in this application?

A. NSP is seeking an ADP for the PRW PPA.

Q. What is the basis for the Company's request for an ADP?

A. Provisions for an advance determination of prudence are set forth in North Dakota law.[3] That provision was amended in 2011 and became law on August 1, 2011. I have conducted my review of this application under the provision of the now-current advance determination of prudence law.

Q. What are the key provisions of the ADP law as it pertains to the Company's application?

A. The statute defines a resource addition as the "construction, modification, purchase, or lease of an energy conversion facility, renewable energy facility, demand response system, transmission facility, or a contract to acquire energy, capacity, or demand response for the purpose of providing electric service. A public utility that intends to make a resource addition may file an application with the Commission for an advance determination of prudence regarding the resource addition."[4] Because the Company will use the energy purchased from PRW to provide electric service, it is my understanding that the Project qualifies for consideration. The Commission may issue an ADP if all of the following conditions are met:

a) The public utility files with its application a projection of costs to the date of the anticipated commercial operation of the facility addition;

b) The commission provides notice and holds a hearing, if appropriate, in accordance with N.D.C.C. § 49-02-02; and

[3] N.D. Century Code § 49-05-16.
[4] Ibid.

c) The commission determines that the facility is reasonable and prudent.[5]

VI. NEED FOR THE PROJECT

Q. Why is the Company seeking to purchase additional wind energy at this time?

A. According to the Company's RFP, NSP seeks to acquire cost-effective wind resources prior to the current expiration date of the Federal Production Tax Credit. As stated on page 1-5 of NSP's Application for Resource Plan Approval 2011-2015 (MPUC Docket E002/RP-10-825):

> "Because the Federal Production Tax Credit ("PTC") is scheduled to expire at the end of 2012, we believe we should continue to explore acquisition of wind power to capture PTC savings for our customers. However, we do not need to add wind power to comply with RES/REO milestones in the next five years. Requesting proposals for additional wind generation prior to the expiration of the PTC provides us with an opportunity to achieve pricing that remains cost-effective for customers under a variety of future scenarios. If the results of our bidding program do not provide adequate benefits we have the option to defer acquisitions and still stay on track with compliance."

According to the application[6] filed by the Company with the Minnesota Public Utilities Commission, the PRW purchase is a cost-effective part of its ongoing efforts to implement a wind acquisition strategy as outlined in our Renewable Energy Plan to meet Minnesota's Renewable Energy Standard ("RES") requirements and similar requirements and goals in the other states we serve in the upper Midwest. NSP further states that it has enough renewable generation to

[5] Ibid.
[6] See page 3 of the Company's June 30, 2011 filing with the Minnesota Public Utilities Commission in Docket No. E-015/AA-11-713. The Minnesota PUC approved this PPA on December 28, 2011.

meet intermediate milestones over the next few years. However, to meet the RES requirements in 2017 and beyond, as well as the renewable energy requirements and goals in the other jurisdictions, NSP must add approximately 2,000 MW of additional wind powered generation to its system by 2020. (Page 7) Current federal tax incentives and market conditions create a significant opportunity to keep the cost of wind additions to its system very cost-effective by adding some additional wind resources now. (Page 11) The Company says it can comply with MN requirements through 2016 through the use of banked RECs.

Q. What do you conclude regarding the need for this Project?

A. I conclude that the PRW PPA is an "opportunity purchase" being made by NSP. This purchase is not needed for capacity, energy, or compliance with renewable energy standards or obligations for at least five years. This purchase is being made purely in anticipation of the expiration of the Production Tax Credit at the end of 2012.

VII. EVALUATION OF RFP METHODOLOGY

Q. Please describe the RFP process employed by NSP?

A. NSP issued an RFP for up to 250 MW of wind on September 16, 2010. Proposals were due October 15, 2010 and NSP received 143 bids on 106 sites totaling 9,189 MW. The Company narrowed this down to a short list of 6 bidders based on pricing, wind turbine availability, site control, the status of plans to interconnect with the MISO system, financial information on the project's developer, and any exceptions to the proposed standard form of the PPA.

Q. What were types of ownership structures were allowed?

A. According to page 1-2 of the RFP, which was provided as Attachment A to Data Request ND PSC 3-1, the RFP allowed for the following ownership structures:

- Purchased Power Agreements ("PPA);
- Community-Based Energy Development ("C-BED") projects;
- Projects that offer NSP asset ownership such as, the acquisition of construction ready sites, options regarding future ownership and development of sites and projects; or
- Any combination of the above.

Q. What were the interconnection and transmission requirements of the RFP?

A. According to page 2 of the RFP, one of the following requirements for the interconnection and transmission must be met:

- The project has an interconnection agreements in place with the Midwest ISO,
- The project is engaged in facilities studies in the definitive planning phase with the Midwest ISO, or
- The project is proposing a "Net Zero" subordinated dispatch arrangement with a peaking generation plant.

Q. Were there any specific requirements for proposals involving Net Zero interconnections?

A. Page 3 of the RFP states that the Bidder shall be responsible to utilize dedicated transmission lines from the project site to the peaking plant substation, the costs for which are included in their proposed pricing.

Q. Was there a preference stated in the RFP for projects located in a certain state?

A. No. The only location requirement was that the project had a Point of Delivery in the MISO system.

Q. Once the bids were submitted, how were they narrowed down to the short list?

A. PPA proposals and projects that would be owned by NSP were evaluated separately. In the evaluation of PPA proposal, the Company focused on proposals with contract prices less than **[TRADE SECRET BEGINS __________ TRADE SECRET ENDS]** on a levelized basis. The Company then asked follow up questions of these proposals to determine which of these projects would be able to move forward in a timely manner. Then, the Company performed a transmission screening to answer the following questions:

- Does the project meet the RFP transmission requirements?
- Does the project have a reasonable chance of obtaining a Generator Interconnection Agreement with MISO, the Transmission Provider, to support a December 31, 2012 in-service date?
- Are there any transmission infrastructure issues that would impact the projects ability to interconnect or result in excessive generation curtailment?

The projects that would be owned by NSP were screened based on interconnection and transmission network requirements, costs and the ability to complete the project by the end of 2012. NSP did not use any a quantitative scoring system for the bid evaluation.

Q. Why were the proposals in North Dakota eliminated?

A. The North Dakota proposals were eliminated for several reasons. About half of the North Dakota proposals were above the **[TRADE SECRET BEGINS ________ TRADE SECRET ENDS]** initial threshold and were eliminated. The remaining proposals were eliminated because of concerns about the feasibility of a 2012 on-line date and/or issues associated with the transmission interconnection.

Q. What is your assessment of the RFP?

A. At a high level, I find the Company's RFP to be reasonable. The project information required of each bidder generally targeted knowledge that would be useful in identifying the desirable projects for further consideration. The availability of the NZIS option, which as the potential to dramatically reduce the cost of developing a wind project through the avoidance of any required system upgrades, was clearly highlighted in the RFP, so all prospective bidders at least knew of this option. I do have some concerns regarding the implementation of the RFP. The Company received **[TRADE SECRET BEGINS ______ TRADE SECRET ENDS]** bids from Projects located in North Dakota. One of these projects was **[TRADE SECRET BEGINS ____________________________ ____ ____ ____ TRADE SECRET ENDS]**. This project was rejected by the Company, and excluded from the short list of projects which moved into a negotiation phase with NSP.

Q. What reasons did the Company offer for not including this project on the short list?

A. This project proposed to interconnect to the MISO system, so it will not incur the "pancaked" transmission charges discussed in the Haeger testimony on behalf of the Company. The Company stated that it rejected this project because it was not sufficiently far along in the MISO system impact study process to achieve an in-service date by the end of 2012. The Company did not provide any additional information on this rationale, nor has it provided the actual bid packages that were submitted by the responders to the RFP.

Q. Do you agree?

A. No. In the Company's testimony, it discusses in detail its commitment to develop new wind projects specifically located in North Dakota, and its past unsuccessful attempts to fulfill that commitment. In light of this situation, I believe that the **[TRADE SECRET BEGINS _____________ TRADE SECRET ENDS]** project should have been placed on the short list. Its proposed pricing was significantly lower than the PRW. Its North Dakota location would have contributed to the fulfillment of NSP's commitment to the State. In addition, achieving an in-service date of December 31, 2012 was not an absolute criterion for complying with the RFP requirements. On page 4, the RFP provides a Schedule/ Timeline for the RFP process, which as noted, is estimated and subject to change. This section of the RFP lists December 31, 2012 as the Latest **<u>Desired</u>**

Commercial Operation Date. (Emphasis added). Given that NSP does not need any new wind resources until at least 2016, it would have made sense to consider such an attractive proposal located in North Dakota, and not simply reject it because it might not be able to achieve a December 31, 2012 in-service date. In doing so, the Company appears to have excluded a project that is much more economical than the chosen project.

Q. Do you have any other concerns?

A. I am also concerned about the equity and fairness of the NZIS approach. I discuss this concern in more detail in the next section of this testimony.

VIII. NET ZERO INTERCONNECTION SERVICE

Q. Please explain the significance of the NZIS.

A. NZIS allows a new generation project to connect to the grid at an interconnection point already approved for an existing generator. As long as the combined output delivered by the two generators does not exceed the capacity approved for the interconnection point, the combined output of the generators has a "net zero" incremental impact on the grid. In the case of Prairie Rose, the project is being constructed to connect to the grid at the interconnection point already approved for Xcel's Angus Anson generating plant. The combined output of the facilities will be electrically controlled to not exceed the maximum output currently allowed for the Angus Anson plant. If necessary, PRW will curtail its output to accommodate generation by the Angus Anson plant.

Q. What is the regulatory status of NZIS?

A. On November 1, 2011 MISO made a Section 205 filing with FERC to revise Attachment X to its tariff. The primary revision was the incorporation of NZIS as a type of Energy Resource Interconnection Service.[7]

Several parties intervened in the docket to protest the revisions on various grounds, including that the nature of NZIS is anti-competitive and violates open-access and transparency requirements. On March 30, 2012 FERC issued an order expressing support for the NZI concept, but required MISO to revise the tariff language further to "ensure that Net Zero Interconnection Service is offered on a fair, transparent, and non-discriminatory basis[8] The revisions are due to be filed by September 30, 2012.

Also on March 30, 2012, FERC issued an order conditionally accepting the provisional generator interconnection agreement ("GIA") for the Prairie Rose project. A provisional GIA allows interconnection prior to completion of necessary network upgrades for traditional interconnection. A generator operating under a provisional GIA is potentially at risk of being curtailed any time there is insufficient transmission capacity from its in-service date until the System Impact Study is complete and the necessary upgrades constructed and placed in-service. FERC's conditional acceptance of the GIA is subject to MISO receiving approval for the tariff revisions to be filed by September 30.[9]

Q. What is the advantage of NZIS from the utility or generator perspective?

A. By utilizing existing transmission capacity, new projects using NZIS are able to

[7] FERC Docket No. ER12-309.
[8] Order Conditionally Accepting Tariff Revisions, FERC Docket No. ER-12-309, ¶302 (March 30, 2012).
[9] Order on complaint and establishing hearing and settlement judge procedures, further Order on interconnection agreement, and dismissing rehearing. FERC Docket No. ER12-188 (March 30, 2012).

interconnect without paying for costly upgrades to the transmission system. In the case of Prairie Rose, it is able to interconnect quickly and without upgrade cost by using the capacity approved at the point of interconnection for the Angus Anson plant. PRW also avoids the MISO process for performing a system impact study. An NZIS does result in greater utilization of the existing transmission system, especially if the transmission capacity is shared with a peaking unit. Such peaking units generally operate at fairly low capacity factors, meaning that they are typically on-line only at the time of the system peak. Thus, in many hours of the year, that transmission capacity might not be used can be used through the NZIS.

Q. Are there disadvantages to NZIS?

A. Yes. There are some significant disadvantages to NZIS. First, because the generator utilizing NZIS can only deliver energy to the grid when the transfer capacity is not being used by the primary generator, there is a chance that there will be periods when the NZIS project will be unable to deliver energy to the grid.

Second, because the project utilizing NZIS does not have guaranteed access to deliver energy, such projects are not eligible to receive capacity credit. This means that the Prairie Rose project will not receive such credit or any associated capacity revenues. This issue is discussed further in Section VIII below.

In addition, the use of NZIS may result in unequal access to the transmission system. In this case, NSP was willing to share Angus Anson's transmission capacity with PRW, because it was buying the output of both units.

However, this does not mean that all owners / operators of existing peaking units would be so willing. If PRW wanted to interconnect at the Split Rock substation, share Angus Anson's transmission capacity, but sell its output to another utility besides NSP, would NSP agree to it? Were other potential bidders unable to secure NZIS because they wanted to sell to another entity? In my view, the use of NZIS raises questions regarding the ability of all prospective transmission customers to gain access to the system on an equal and non-discriminatory basis.

Lastly, the use of NZIS raises economic concerns. PRW has received a valuable asset - namely the right to use existing transmission capacity - which has been paid for by NSP ratepayers. In theory, PRW should have lowered its bid price by the value of that asset. Unfortunately, since PRW bid a bundled price, we have no idea if the full value of the asset given to PRW will accrue to NSP ratepayers. The question to be asked is: What would NSP charge PRW for the right to use existing transmission capacity if some other utility besides NSP were buying the output of PRW. This should be the amount by which PRW has reduced its bid. The use of NZIS by PRW at an unknown cost may actually have allowed PRW to obtain prices in excess of its reasonable cost and still remain cost competitive versus other projects on the short list that NSP were also negotiating with in parallel.

Q. Will the Prairie Rose project eventually pursue conventional interconnection?

A. No. The Company's initial testimony indicated that transitioning the Prairie Rose project to conventional interconnection was an option.[10] In subsequent discussions with the Company and responses to discovery questions, however, NSP has made it clear that there are no plans to pursue conventional interconnection.[11, 12]

Q. Are there any outstanding risks associated with NZIS?

A. Yes there are. In addition to the disadvantages noted above, there is some regulatory uncertainty that may jeopardize the benefits of NZIS. MISO is seeking FERC approval to revise its tariff to explicitly define NZIS as an interconnection option, but the tariff revision filing has not yet received final FERC approval. FERC has conditionally accepted the Prairie Rose provisional interconnection agreement pending MISO's tariff revisions. The interconnection agreement will remain conditional until FERC's final order.

The Company is confident that the tariff revisions will be approved and that the conditional approval will stand. However, there is still some risk that it will not be approved and this could jeopardize the viability of the project. If the project is required to obtain conventional interconnection, it could threaten its viability, depending on the cost of required upgrades.

Q. What do you conclude regarding the use of NZIS?

A. It is probably too late to change anything for this RFP. If the Commission denies the Company's request for an ADP, then the issue is moot. In future RFPs where the use of NZIS is allowed, the Company should address the issues I have raised herein.

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[10] Haeger Direct, p. 14:4-12.
[11] Response to ND PSC 1-12(a).
[12] Response to ND PSC 3-6(a).

IX. STRATEGIST ANALYSIS

Q. Please provide an overview of NSP's Strategist analysis.

A. The Company utilized the Strategist resource planning model to evaluate the reasonableness of the PPA. The modeling is described in the Application as well as the Wishart Direct Testimony. Essentially the analysis models a base case of the Company's system without the Prairie Rose project and compares the production cost of this base case to a scenario in which the Prairie Rose project is added as an available resource. The total system cost for each scenario is presented as the present value of revenue requirement (PVRR) and the difference between the total PVRR for scenarios represents the impact of the PPA to the system.

Q. What were the results of the Strategist analysis?

A. The Company's Application states that the Strategist analysis showed that the Prairie Rose PPA would have a total impact of $5.4 million on the PVRR of the system.[13] This is a total for the whole system, and North Dakota's share of this would be $0.3 million, assuming a 5.8% load ratio share.[14]

Q. Do you have any concerns related to the methodology of the analysis?

A. Yes I do. I have reviewed workpapers provided by the Company related to the Strategist analysis and I believe that the $5.4 million estimate significantly understates the actual impact of the Prairie Rose PPA. There are two major flaws in the analysis that yielded the low impact: the inclusion of a capacity credit that

[13] Application, p. 12.
[14] Response to ND PSC 1-10.

will not be available for the Prairie Rose project, and the use of a natural gas forecast that was significantly higher than estimates in the Company's possession at the time that the Application was filed.

Q. Please explain the issue with the capacity credit.

A. At the time of filing the Application, MISO allowed wind resources to receive capacity credit for 12% of the total nameplate capacity (24 MW for the Prairie Rose project). The Company's Strategist modeling incorporated revenue from this credit in the model run that included the addition of the Prairie Rose project.[15] However, this is an inappropriate assumption because the Project will not receive this credit (or revenue) as a result of the interconnection by NZIS.

Q. Was the Company aware that the Prairie Rose project will not be eligible for this capacity credit?

A. Yes. The Haeger Direct Testimony admits that because of the NZIS, "Prairie Rose will not qualify for an additional capacity credit…"[16] The testimony appears to suggest at points that the Company could pursue a conventional interconnection in the future when additional transmission capacity is added as part of MISO's CapX2020 projects.[17] However, the Company has since clarified that the PPA is structured as an NZIS project and there is no intention to transition to conventional interconnection, which would be necessary to receive the capacity credit.[18,19]

[15] Haeger Direct, p. 14.
[16] Ibid, p. 13:25-26.
[17] Ibid. p. 14:4-12.
[18] Response to ND PSC 1-12(a).
[19] Response to ND PSC 3-6(a).

Q. What is the impact on the PVRR if the capacity credit is removed from the analysis?

A. As noted in Company testimony, the loss of the capacity credit revenue adds $18 million to the net impact on the PVRR.[20] Assuming the same 5.8% responsibility for North Dakota, this equates to an additional $1.04 million to ratepayers in the state.

Q. Please explain your concern with the natural gas price forecast used in the Strategist analysis.

A. The Company performed the Strategist analysis using a natural gas forecast from January 2011. As a sensitivity case, the Company duplicated the Strategist analysis using a natural gas price forecast 20% lower than the base case forecast. Figure 1 below compares the base case and low scenarios.

[20] See Haeger Direct, p. 14:4-23 and Wishart p. 4:23-5:5.

Figure 1
Strategist Scenario Natural Gas Forecasts ($/MMBtu)[21]
[TRADE SECRET BEGINS

TRADE SECRET ENDS]

The natural gas price forecast is a critical assumption impacting the Strategist results. The Company's analysis shows that the Strategist run using the lower gas price yields a PVRR impact of $46.2 million, an increase of $40.8 million over the $5.4 million impact reported in the Application.[22]

The Company has stated that it updates its natural gas forecast almost daily.[23] In the quarterly forecast data provided, it is clear that price outlooks were moving progressively lower over the course of 2011. By the time the Company filed the Application on January 31, 2012, the then-current natural gas forecast was substantially lower than the January 2011 forecast – approximately 25% lower for 2013 – and decreased further by the time the Company filed testimony

[21] Response to ND PSC 1-6, Attachment B; Response to ND PSC 1-1, Attachment B. The abrupt change in the low price scenario in the year 2048 was included in the Company's workpapers.
[22] Calculated using data derived from Response to Data Request ND PSC 1-7, Attachment E.
[23] Response to Data Request No. ND PSC 1-1(b).

on June 7, 2012. Figure 2 below compares the base case and low price scenarios used in the Strategist analysis with forecasts in the Company's possession in January and July 2012.[24]

Figure 2
Natural gas price forecast comparison ($/MMBtu)[25]
[TRADE SECRET BEGINS

TRADE SECRET ENDS]

Q. Do you believe it was reasonable for NSP to utilize the January 2011 forecast in its economic evaluation of the project?

A. No, I do not. By the time the Company filed the Application on January 31, 2012, it was clear that natural gas prices were dropping and the then-current forecasts were closer to the prices used in the sensitivity case with 20% lower prices. With the significant impact natural gas price assumptions have on the PVRR, I believe it would have been appropriate to present the results of the sensitivity case ($46.2 million PVRR impact) in the Application along with the base case results ($5.4

[24] Response to ND PSC 1-6, Attachment B.
[25] Response to ND PSC 1-6, Attachment B; Response to ND PSC 1-1, Attachment B.

million PVRR impact).

Q. Do you have any other concerns regarding the economic analysis?

A. The PPA appears to contain a provision to increase the price if actual losses between PRW and the interconnection point exceed a certain level. This provision was not part of the standard contract that was attached to the RFP, so it must have been added during the negotiation between NSP and PRW. This potential increase in price was not included in the Company's analysis, and it seems to be a violation of the spirit of the RFP.

Q. What conclusions do you draw from your review of the Strategist analysis?

A. In general, I support the use of the Strategist analysis as a method of evaluating the economic impact of the PPA. However, based on my review of the assumptions used in the modeling, I present the following conclusions:

- <u>Capacity credit</u>. Based on the testimony and discovery responses, neither the Company nor PRW appears to have any intention of ever pursuing conventional interconnection of the Prairie Rose project and receiving the capacity credit. If this is the case, the capacity credit should not have been included in the PVRR results reported in the Application. As written, the Application reports a low cost of the Prairie Rose project to the system.
- <u>Natural gas forecast</u>. I understand that forecasts are changing rapidly. However, at the point of filing the Application, the Company had information to suggest that the results of the sensitivity case may be a more accurate representation of the costs of the project. My view is that for the Commission to approve the project it should be aware that the

higher estimate of PVRR impact resulting from the lower gas price forecast is likely to be a more accurate representation of the actual impact of the PPA, rather than the base case results presented by the Company.

Q. What is the combined impact of the two changes you suggest?

A. The results presented in the Company's application state that the total PVRR impact is $5.4 million or $0.3 million for North Dakota ratepayers. Removing the capacity credit adds an impact of $18 million and using the lower gas forecast adds $40.8 million. Incorporating these two changes yields a new total PVRR impact of $64.2 million for the system and $3.72 million for North Dakota ratepayers. This means that the PRW PPA is expected to cost $64.2 million more than alternative resources on a net present value basis.

X. COMPARISON TO GAS ALTERNATIVE

Q. Please provide an overview of NSP's analysis comparing the Prairie Rose PPA to the natural gas alternative.

A. In order to compare the cost of energy under the PPA to alternative generation from a natural gas plant, the Company provides a comparison of pricing using a hypothetical gas generator with a heat rate of 7,000 btu/kWh. The price of energy from the gas plant consists of the fuel cost (calculated using a gas price assumption and heat rate), variable O&M, and a capacity cost adder. The Company performed the analysis using the base case and low gas price scenarios discussed above.[26] The cost of energy from Prairie Rose in this analysis consists of the PPA price and a wind integration cost. The results of the analysis reported

[26] Response to ND PSC 1-3, Attachment A.

in the Application show that beginning in 2016 the wind cost is lower than the cost of energy from the gas generator under either set of gas price assumptions.[27]

Q. Do you have any concerns with this analysis?

A. Yes. I have identified a few issues with the analysis that I believe require more clarity:

- Natural gas price assumptions
- Capacity cost adder
- Wind integration cost adder
- Inconsistent results with Strategist analysis

Q. What are your concerns with the natural gas price assumptions?

A. The Company presented the results of the analysis of energy from gas generation using both their base case and the low cost case include a 20% reduction in gas cost. As I have discussed previously, I believe that the lower estimate should be the primary point of comparison, rather than the base case.

Q. What are your concerns with the capacity cost adder?

A. The capacity cost adder is included in the price of the gas alternative to offset the capacity accreditation that the Company initially assumed that the project would be receiving a capacity credit for 12% of the project size. The wind price used in the analysis includes the PPA price and the wind integration cost. Offsetting these costs, according to the analysis, is the capacity revenue that the project could theoretically receive. When comparing the cost of wind energy to the

[27] Application, pp. 11-12.

natural gas alternative, the Company added to the cost of gas alternative energy a capacity cost equal to the credit the Prairie Rose project could receive.[28]

As I have discussed previously in this testimony, this is not a reasonable assumption by the Company's own admission, so this cost should be removed from the analysis. The Company acknowledges this fact as well.[29]

Q. If the capacity cost adder is removed from the cost of the gas alternative, what is the impact on the results of the analysis?

A. If the capacity cost is removed, the marginal savings from energy from the wind PPA is reduced. Figure 3 below recreates the graph from page 12 of the Application excluding the capacity cost adder.

Figure 3
NSP's Comparison of Prairie Rose PPA to Natural Gas Alternative
[TRADE SECRET BEGINS

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[28] Response to ND PSC 4-9.
[29] Response to ND PSC 4-9(d).

Using the lower gas forecast and removing the capacity cost adder, the marginal benefit of the PPA is significantly reduced.

Q. What are your concerns with the wind integration cost adder?

A. According to the Company, the wind integration cost adder includes the cost of "additional ancillary services required to maintain system stability in the presence of variable wind generation."[30] These ancillary services are typically provided by gas generators, so this cost as described by the Company is variable, dependent on gas prices. Therefore, if the low gas price scenario for the gas alternative is the primary point of comparison as I've suggested, it would be appropriate to also reduce the wind integration cost adder. The data provided by the Company is not sufficient to perform this adjustment. Hypothetically, if the wind integration cost adder consisted entirely of gas purchases, an appropriate adjustment would be to reduce this cost by 20%. The impact on the overall price of energy from PRW does decreases only marginally with a lower wind integration cost, as shown in Figure 4 below.

[30] Response to ND PSC 1-13(c).

Figure 4
Comparison of Prairie Rose PPA (with lower wind integration cost) to Natural Gas Alternative
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TRADE SECRET ENDS

Q. What are your concerns with the inconsistency between the results of the analyses?

A. The results of the Strategist analysis and the results of the gas alternative analysis present a considerably different view of the benefits of the wind PPA. **[TRADE SECRET BEGINS** ____ ____ ____ ____ ____. **TRADE SECRET ENDS]**

It is not surprising that the analyses yielded different results since they compare the cost of the PPA energy to significantly different benchmarks.

However, I do not think it is appropriate to use both analyses to support the Application.

Q. Do you have an opinion as to which analysis should be utilized in the evaluation of the PPA?

A. Yes I do. Since the addition of the energy of the PPA will not exclusively displace energy from natural gas generation, I do not believe that the natural gas alternative analysis is the most relevant to the determination of the prudence of the agreement. The Strategist analysis provides a more accurate and comprehensive view of the economic impact of the PPA on system costs.

Q. Please summarize your conclusions related to the natural gas alternative analysis.

A. As I have discussed, the inclusion of the capacity cost as part of the natural gas alternative price is inappropriate and should be removed. Additionally, as I have discussed previously in this testimony, I believe that the lower gas forecast is a more appropriate scenario to evaluate. When both of these changes are incorporated, the result is that the incremental benefit is substantially reduced.

Furthermore, I do not believe that the gas alternative analysis is the most appropriate way to evaluate the reasonableness of the PPA. Rather, my view is that the Strategist analysis is a more accurate representation of the impact of the project.

XI. DISPOSITION OF RENEWABLE ENERGY CERTIFICATES

Q. What are renewable energy certificates (RECs)?

A. RECs represent the renewable attributes of electric generation including rights to all environmental, social or other non-power benefits of renewable generation. RECs can be sold separately from the power attributes of generation and one REC represents one MWH of renewable power.

Q. How are they tracked?

A. RECs created in the NSP service area are tracked in the Midwest Renewable Energy Tracking System (M-RETS).

Q. Do North Dakota Customers currently accrue RECs as part of NSP's existing renewable energy contracts?

A. Yes. According to NSP's response to data request ND PSC 1-10, North Dakota customers are allocated about 5% of Northern States Power's renewable generation. The RECs associated with this generation accrue to North Dakota customers and cannot be used for compliance by Northern States Power in other states it serves.

Q. Do these RECs have value to North Dakota Customers?

A. Yes. The RECs could be sold and the proceeds used to offset the cost of power.

Q. Who are the potential buyers for the RECs?

A. NSP is prohibited from selling RECs to the other utilities in Minnesota until 2021 and would not be able to sell RECs alone to Wisconsin utilities for compliance with that state's RPS because the Wisconsin policy requires that the renewable power is used to meet the utilities retail load obligation. This leaves the voluntary REC markets for the majority of resource types. The one potential market for the compliance RECs is the North Carolina utilities which may buy out of state RECs for 25% of their compliance.

Q. What is the value of RECs to North Dakota Customers?

A. The value of RECs on the voluntary market is currently between **[TRADE SECRET BEGINS ____________ TRADE SECRET ENDS]** per REC generated in 2012. The value of out of state RECs in North Carolina should be similar to the voluntary market for most resources, but is significantly higher for poultry waste facilities due to a set-aside for poultry facilities in the state policy. There are very few poultry waste facilities making the RECs quite valuable. In response to Data Request No. ND PSC 1-18, NSP stated that it had sold poultry RECs in North Carolina for **[TRADE SECRET BEGINS ____________ TRADE SECRET ENDS]**

Q. What is NSP's current policy regarding RECs accruing to North Dakota Customers?

A. NSP stated in discussions with La Capra Associates that it is not their current policy to sell all RECs that accrue to North Dakota Customers as they are generated. The policy is to hold onto RECs until NSP believes the price is high enough to warrant selling. The hope is that RECs will be more valuable in the future. To date the only REC sale that NSP has completed is the sale of the poultry waste RECs in North Carolina. No other REC sales have been completed.

Q. Is this consistent with Commission ruling in Case PU-10-019?

A. No. In Case PU-10-019, the Commission orders NSP to set up a pilot program to sell excess RECs allocated to North Dakota customers. All RECs are to be considered excess through 2015 and 90 percent of the REC revenue is to be returned to North Dakota customers. The Company retains the other 10%. While the Commission acknowledges that the REC market is not a mature market, it does not specify a price below which NSP should not sell the RECs.

Q. If NSP were to sell all RECs allocated to North Dakota customers through 2015 at current prices, what would be the impact to customers?

A. According to *Xcel Energy's Renewable Energy Rate Impact Report* attached to the response to Data Request No. ND PSC 2-4, NSP will generate about 8,000,000 RECs per year between 2012 and 2015 of which about 5% or 400,000 will accrue to North Dakota Customers. If RECs are valued at \$0.50, this would equate to \$200,000 per year and it would be \$400,000 per year if REC prices are \$1/MWH. In 2015 and beyond, NSP will need to retire about half of these RECs to meet North Dakota's renewable energy goals. If NSP adds more renewable energy to its portfolio, the revenue from REC sales could be even higher.

Q. Will North Dakota Customers accrue RECs as part of the Geronimo Wind PPA?

A. Yes. According to Attachment A to Data Request ND PSC 1-18, North Dakota customers will be allocated 40.6 GWh per year from the Geronimo wind project.

Q. What is the value of these REC?

A. These RECs would be sold on the same voluntary market described earlier and would currently be valued between \$0.65 and \$0.95. In Data Request ND PSC 1-18, NSP calculated the NPV of these RECs over the life of the project to be \$384,000 if a \$1/MWH REC price is assumed. If prices increase and RECs sell for the \$3/MWH, the NPV would be \$1 million to North Dakota ratepayers.

Q. What REC value has NSP cited in its testimony?

A. Mr. Haeger cites a REC value of $3/MWH or an NPV of $1 million in his testimony. (Page 16:13-14)

Q. What is your recommendation with regard to REC sales?

A. I recommend that NSP sell the RECs on behalf of North Dakota Customers. Unless the REC markets in the region change, RECs generated at the PRW facility are likely to be sold on the voluntary market. According to NSP's response to Data Request No. ND PSC 4-24, newer vintages of RECs are more valuable on the voluntary market. If the PRW PPA is approved, NSP should sell the RECs generated by PRW in a timely manner to ensure that the value to North Dakota customers is maximized and the costs are minimized.

XII. CONCLUSIONS AND RECOMMENDATIONS

Q. Would you summarize your findings with respect to the issues before the Commission in this proceeding?

A. My findings are as follows:

- There is no real need for this project. This PPA is an "opportunity buy" and a hedge against the potential expiration/ non-renewal of the PTC.
- The form of RFP is generally reasonable. It solicits typical information that can be used to select winning project(s). All potential bidders were given adequate notice regarding the ability to utilize a NZI.
- I do have some concern regarding implementation of RFP. The early rejection of the **[TRADE SECRET BEGINS ________________ TRADE**

SECRET ENDS] project in ND, which has a much lower PPA price than PRW, may have eliminated a more desirable alternative to PRW. Despite adequate notice, concerns remain with the NZI. There is regulatory uncertainty regarding final approval by FERC. Furthermore, issues of non-discriminatory access remain, and the lack of a valuation of the NZIS effectively results in a non-transparent transfer payment to PRW.

- According to the Company's own filing, the project is not economic when compared to other conventional resources. With updated natural gas prices and the elimination of capacity value from the economic analysis, the economic comparison becomes even less favorable.
- PRW may not be the best wind project available from the RFP.

I conclude that because this project is not needed and because it is more costly than other alternatives, the proposed PPA is not in the public interest. Hence, I recommend that the requested ADP not be granted.

Q. Does this conclude your testimony?

A. Yes. It should be noted that at the time of the filing of this testimony, some discovery responses may still be outstanding or in the process of being reviewed. I will supplement this testimony as appropriate to reflect any new information received subsequent to filing.