Public Document
Trade Secret Data Excised

DIRECT TESTIMONY AND SCHEDULES

JAMES A HEIDELL

STATE OF NORTH DAKOTA

BEFORE THE

NORTH DAKOTA PUBLIC SERVICE COMMISSION

NORTHERN STATES POWER COMPANY ADVANCE PRUDENCE – 1,550 MW WIND PORTOFLIO

CASE NO. PU-17-120

EXHIBIT
tabbies
PSC-1

TABLE OF CONTENTS

I. Introduction and Qualifications

Q. Would you please state your name, affiliation, and address?

A. My name is James A. Heidell. I am a Director at PA Consulting Group ("PA"). My business address is 1700 Lincoln Street, Suite 1550, Denver, CO 80203.

Q. On whose behalf are you filing this testimony?

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

Q. Please summarize your qualifications and experience.

A. I have worked in the energy industry for the past 35 years, primarily specializing in electricity and utilities. I have worked on issues related to resource planning, rates, analysis of electricity markets, and analysis of the economics of financial transactions for utilities and wholesale generation owners. My academic background includes a BSE in civil engineering from Tufts University, a MS in engineering economics from Stanford University, and a MBA in finance from the University of Washington. I am a Chartered Financial Analyst. My CV is provided in Exhibit JAH-1.

Q. Have you testified before the North Dakota Public Service Commission previously?

A. Yes. I testified on behalf of Montana-Dakota Utilities in the matter of Montana-Dakota Utilities Co., and Otter Tail Corporation; Advance Determination of Prudence, Big Stone II Generating Station Case Nos. PU-06-481 and PU-06-482.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide the Commission with my assessment of the Northern States Power Company – Minnesota ("NSP" or the "Company") proposal to build, and contract, for an additional 1,550 MW of wind generation Projects to come on-line in 2019 and 2020 ("1,550 MW of Wind" or "Wind Portfolio"). NSP has applied for an Advance Determination of Prudence ("ADP") for the Wind Portfolio ("Application"). I have reviewed the Application, supporting testimony, and responses to interrogatories in order to develop a recommendation regarding whether:

- the proposed wind generation Projects will lower electricity costs for NSP's North Dakota customers;
- the wind generation Projects are needed;
- some or all of the wind generation Projects that comprise the Wind Portfolio should be approved under the ADP; and
- conditions should be put on an approval of the ADP.

Q. Would you please summarize the organization of your testimony?

A. Yes. I start with presenting my findings and recommendations and then I discuss in detail the analysis conducted to support my findings and recommendations. I then address additional factors considered. Finally, I address proposed conditions that should be included on approval of the ADP. My analysis is separated into six sections:

- A review of the Wind Portfolio evaluated (Section IV);
- An assessment of the need for the Wind Portfolio (Section V);
- An evaluation of the Company's modeling of the Wind Portfolio using Strategist (Section VI);
- An assessment of whether congestion and curtailment costs are likely to significantly degrade the economics of the wind generation Projects that comprise the Wind Portfolio (Section VII);

- Consideration of the value of the wind generation Projects in the context of the Midcontinent Independent System Operator ("MISO") market operations (Section VIII); and
- An assessment of the expected energy cost savings to the Company's North Dakota customers (Section IX).

Q. Are you sponsoring any exhibits to your testimony?

A. Yes. I am sponsoring the following exhibits:

- Exhibit JAH-1: CV of James Heidell
- Exhibit JAH-2: Distribution of Historical LMPs at Proxy Node
- Exhibit JAH-3: Market-Based Calculation of Wind Project Revenues

II. Summary of Recommendations

Q. What is your recommendation with regards to approving the Company's Application for an ADP to add an additional 1,550 MW of Wind to the NSP integrated system?

A. My recommendation is that the Commission conditionally approve the Application on the basis that the wind generation Projects are individually and collectively projected to lower electricity costs for NSP's North Dakota customers. However, I note that there is no immediate need for the capacity provided by the 1,550 MW of Wind and that the Projects are not needed as a result of any North Dakota statute or regulatory requirement. My recommendation is consequentially based solely on the projected economic benefits of the Projects, based on their lowering electricity costs. I evaluated these economic benefits based upon information presented by the Company, supplemented by my evaluation of their analysis and my own supporting analysis.

Q. What conditions should this Commission put on the approval of the ADP?

A. As I noted, my recommendation for approval is based on the conclusion that the Wind Portfolio will lower electricity costs for NSP's North Dakota customers compared to the alternative of not developing the Wind Portfolio. In order for customers to realize these projected savings, it is necessary for the Company to:

- Secure 100% of the Production Tax Credits ("PTC") for all of the Projects;
- Secure interconnection to the MISO grid and firm transmission service within the stated budgets;
- Construct the four self-build Projects within the stated budgets; and
- Ensure that the third party Project builders deliver the Projects on budget.

Therefore, I recommend the following conditions on the approval of the ADP with regard to the allocation of the cost of the Wind Portfolio:

- The Company's shareholders should be responsible for any shortfall as a result of not securing 100% of the PTC rate;
- Recovery of Project construction, interconnection, and transmission costs for the four self-build Projects should be limited in aggregate to no more than **[TRADE SECRET]** (adjusted for any Projects not constructed);
- Construction costs for the two wind generation Projects that are third party built, owned and transferred to the Company ("BOT") should be limited to no more than **[TRADE SECRET]**in aggregate (adjusted for any Projects not constructed);
- The Company should be provided an incentive if the four self-build Projects collectively are constructed and interconnected below the budget;
- As part of its monthly fuel cost adjustment filings to the Commission, the Company should provide monthly reports of curtailment and negative pricing observations at each of the seven Projects, including any known reasons for observed curtailment and negative pricing; and
- The Company should provide quarterly construction progress reports to the Commission until the last Project is in service, indicating the development status of each Project.

III. Findings

Q. Would you please provide a summary of the findings in your testimony that support your recommendation regarding the Commission's approval of the ADP?

A. Based upon my review and analysis of the testimony filed in the Application, the exhibits contained within the Application, and the information produced in discovery, I conclude the following:

- The wind generation Projects are anticipated to dispatch into the MISO market at prices that will result in margins that ultimately yield electricity cost savings for North Dakota customers. Resources in MISO are dispatched based upon short run marginal costs ("SRMC"), subject to constraints on generation units and transmission. With SRMC of virtually zero, the proposed Projects will dispatch ahead of thermal resources and generate margins that are projected to lower the Company's overall electricity costs.
- The levelized costs of the Projects are below the likely alternative market energy and capacity cost. The Company's estimated savings, expressed as the Present Value of Revenue Requirements ("PVRR"), are approximately $1,599 million (in 2017 dollars) for the total NSP integrated system over twenty five years. Using a simplified yet reasonable methodology, I developed an alternate baseline estimate of $1,417 million in 2017 dollars.
- I have made adjustments to my baseline estimate to come up with expected electricity cost savings in the range of $782 million – $1,417 million.
- The Projects are not needed for capacity. As with all wind projects, these Projects provide limited capacity benefit to the system relative to their nameplate capacity. The capacity, at least in the future, should have some value. However, the Company notes that it does not need capacity until the mid-2020s timeframe.
- Local transmission congestion may result in the degradation of the value of certain Projects, but not to the extent that the Projects will increase electricity costs to NSP's North Dakota customers. Both the Company and I have concluded that while there will likely be some congestion costs associated with these

Projects, those costs are not expected to materially impact the projected electricity cost savings. The Company's analysis of savings includes an estimate of congestion costs and intermittent generation integration costs.

- A change in projected market fundamentals, such as very low natural gas prices, could reduce the proposed Projects' overall savings. However, the savings are not projected to be eliminated even in a very low natural gas price environment (as observed in 2016, where sub $2.50/MMBtu average natural gas prices yielded average MN Hub energy prices of approximately $20.70 per MWh, approximately **[TS]** per MWh above the average levelized cost of the Wind Portfolio). This is due to the fact that the levelized cost of the Portfolio remains competitive with the variable costs of MISO coal-fired generators and higher heat rate natural gas-fired generators (even in a $2.50/MMBtu natural gas price environment).
- No adverse impacts to North Dakota reliability were identified. Neither the Company nor I have identified any adverse impacts to reliability associated with these Projects.
- The estimation of ratepayer benefits conforms to North Dakota requirements to exclude externalities.

IV. Overview of the 1,550 MW Wind Portfolio

Q. What are the wind generation Projects that the Company is proposing?

A. The Company is proposing to acquire a 1,550 MW portfolio of wind generation Projects to be added to the NSP integrated system. The Portfolio includes eight Projects at seven locations: two of which are Purchase Power Agreements ("PPA"), four of which company built and owned, and two of which are third party BOT. The proposed Portfolio is described in Table 1. All of the Projects are projected to be in-service by the end of 2020. The 2020 end date is critical since the Projects must be in service within four years of the end of the year that construction commenced. The Company, through the purchase of components for the self-build projects, has established a 2016 construction start date, which is necessary for receiving the full PTC versus a reduced or zero value PTC. Both the start and end dates are critical, since starting construction by the end of 2016 and completing construction within four years are two of the requirements for qualifying for the full PTC under IRS Safe Harbor and Continuity Safe Harbor requirements.[1]

Table 1. Proposed Wind Projects

Project Name	Size(1)	Type(2)	Location	In-Service Date
Blazing Star I	200 MW	Self-Build	Lincoln County, MN	4Q 2019
Blazing Star II	200 MW	Self-Build	Lincoln County, MN	3Q 2020
Freeborn	200 MW	Self-Build	Freeborn County, MN Worth and Mitchell Counties, IA	4Q 2020
Foxtail	150 MW	Self-Build	Dickey County, ND	3Q 2019
Clean Energy #1	100 MW	PPA	Mercer and Morton Counties, ND	4Q 2019
Crowned Ridge	600 MW	BOT/PPA	Codington County, SD	4Q 2019
Lake Benton	100 MW	BOT	Pipestone County, MN	4Q 2019

(1) Nameplate rating
(2) Self-Build: Projects developed and owned by the Company
BOT: Build – Operate – Transfer. Developed and constructed by a third-party, then purchased, owned, and operated by the Company thereafter.
PPA: Power Purchase Agreement.

Q. What is the status of each proposed wind generation Project's interconnection agreement?

A. Each wind generation Project was assigned to one of MISO's Definitive Planning Phase ("DPP") cycles to conduct an Impact Study, which determines what transmission constraints must be addressed to maintain system reliability. Some of the Projects' Impact Studies are complete, while the majority are still pending. The status of each Project's interconnection is provided below in Table 2.

[1] IRS Notice 2017-4

Table 2. Interconnection Status

Project Name	MISO DPP Cycle	Estimated Completion	Estimated Cost of Network Upgrades	Estimated Cost of Interconnection
***** Trade Secret Data Begins				
Blazing Star I	Feb 2016	Dec 2017	[TS]	[TS]
Blazing Star II	Aug 2016	June 2018	[TS]	[TS]
Freeborn	Feb 2015	TBD(2)	[TS]	[TS]
Foxtail	Aug 2014	Aug 2016(1)	[TS]	[TS]
Clean Energy #1		May 2014	[TS]	[TS]
Crowned Ridge	Feb 2015 Aug 2015 Feb 2017	3Q 2018	[TS]	[TS]
Lake Benton	NA(3)	NA	[TS]	[TS]
Trade Secret Data Ends *****				

(1) Foxtail's Generator Interconnection Agreement ("GIA") was executed August 30, 2016.
(2) Freeborn's Impact and Facilities Studies are complete, and the GIA is under negotiation.
(3) Lake Benton is a repowering of the existing Lake Benton II wind facility, in operation since 2000. Lake Benton will use the existing interconnection.

Q. What is the estimated construction cost and total levelized cost for each wind generation Project?

A. The estimated construction cost and Levelized Cost of Energy ("LCOE") for each Project are shown in Table 3. LCOE is an economic assessment of the discounted annual cost to build and operate a power generating asset over its lifetime, divided by the discounted annual energy output of the asset over the same lifetime.

The Clean Energy #1 Project, one of the Projects that has a rebuttable presumption of prudence under North Dakota law since it is located in North Dakota, is shown as the most expensive of the seven Projects. It is also the smallest Project at 100 MW. However, it is important to note that while the Clean Energy #1 Project is a 20-year PPA, the Company calculated the LCOE on a 25-year basis so that all Projects are compared over a consistent timeframe.[2] The LCOE over the 20-year contract is **[TS]**/MWh. The

---

[2] Advanced Prudence – 1,550 MW Wind Portfolio Application, p 35.

Company inserted an assumption that the Project would be paid the market avoided cost of energy for the output for years 21–25. It does not appear that the Company has the obligation to extend the PPA. My perspective is that an extension would not necessarily be priced at the market avoided cost of energy, but rather what the Company could procure replacement generation under a new wind contract selected through competitive bidding.

It is important to note that the LCOE does not translate into an equal cost to ratepayers in each year. The Company-owned assets will have a large rate base in the initial years that decreases as the Projects are depreciated. However, the ten years of the PTC offsets the rate base, and the revenue requirement increases after ten years. The rate treatment will also depend on the treatment of the PTC. In addition, the PPAs are not structured as levelized payments. For example, Clean Energy #1 has a low payment for the first ten years and then the rate increases for the last ten years of the contract. Alternatively, the Crowned Ridge PPA [**TRADE SECRET**]. The revenue requirement implications of the owned wind generation Projects and the PPA wind generation Projects are discussed in the Section VII (the economic analysis section) of my testimony.

Table 3. Project Costs

Project Name	Construction Cost	Network & Interconnection	Total Cost**	LCOE
***** **Trade Secret Data Begins**				
Blazing Star I	[TS]	[TS]	[TS]	[TS]
Blazing Star II	[TS]	[TS]	[TS]	[TS]
Freeborn	[TS]	[TS]	[TS]	[TS]
Foxtail	[TS]	[TS]	[TS]	[TS]
Clean Energy #1 (PPA)	[TS]	[TS]	[TS]	[TS]
Crowned Ridge (PPA)	[TS]	[TS]	[TS]	[TS]
Crowned Ridge	[TS]	[TS]	[TS]	[TS]
Lake Benton	[TS]	[TS]	[TS]	[TS]
Trade Secret Data Ends *****				
** Total costs include AFUDC, construction and interconnection do not include AFUDC				

V. Resource Need

Q. Does the Company need these wind generation Projects to satisfy a capacity need or reserve margin requirement?

A. No. The Commission employs a "need + least cost" requirement when evaluating new resources. The Company has identified in a separate docket, and referenced in this docket, that it does not anticipate a capacity shortfall until the mid-2020s.[3]

> "Xcel Energy does not anticipate a load serving need to arise until the mid-2020's, after the Wind Portfolio will be fully in-service."
> [Page 3 of the Application]

Q. Why should the Commission grant an ADP for these wind generation Projects if they do not conform to the Commission's "need + least cost" requirement for new resources?

A. The Company asserts that because the wind generation Projects are projected to lower the Company's system average cost, the Projects should be considered "least cost". Further, the Company argues that the Projects will add capacity to the Company's system in anticipation of the mid-2020s capacity need. The Company also notes in its Application that the Commission has approved prior wind projects which were not strictly needed for capacity purposes at the time of their approval.

Q. Do you agree that the wind generation Projects could be considered least cost and will satisfy a future capacity need?

---

[3] Case No. PU-12-813, in the Company's Application for a Resource Treatment Framework

A. Yes. An initial indication of a Project's cost effectiveness is its LCOE. The Company's Projects have LCOE values which are lower than the Company's system average cost and expected MISO market clearing prices.[4] Further, when the Projects' production is included in the Company's system planning models, the models indicate that the Projects are cost effective. I discuss the economic evaluation of the proposed Projects in more detail in Sections VII and IX below.

Q. How do the proposed wind generation Projects impact the Company's generation mix from a resource diversity perspective?

A. The Company has been steadily increasing the percentage of wind resources in its generating portfolio since the mid-2000s. Prior to the addition of the proposed Projects, in 2015 the Company's system energy consisted of approximately 27 percent nuclear, 34 percent coal, 14 percent wind, 15 percent natural gas, and 10 percent hydro, biomass, and other renewables. After the addition of the proposed Projects and other clean energy sources, the wind portion of the system energy is projected to increase to 25 percent by 2030.

Q. What are the implications of the Company's system becoming increasingly reliant upon Variable Energy Resources ("VER") such as wind generation?

A. The Company will need to rely upon MISO for integration of VERs. MISO requires certain ancillary services (i.e., contingency and regulating reserves) and revenue sufficiency guarantees to be borne by the costs of wind generation and other VERs. Additionally, increased wind generation is projected to cause increased costs to the Company's coal-fired generation through increased cycling, and additional costs for gas storage to manage the variability in natural gas-fired generation due to VERs.

---

[4] System cost from Strategist analysis, NDPSC-2-003 Attachment A

Q. Were the costs of relying upon MISO to integrate the Projects onto the system considered in the Company's analysis?

A. Yes. The Company relies upon the 2015 Wind Integration study prepared for NSP by EnerNex for estimates of MISO integration costs and coal plant cycling costs. The study was commissioned by NSP at the Minnesota Public Utility Commission (MPUC's) direction and the purpose of the study was to determine the cost of integrating an additional 1.8 GW of wind into NSP's system. Assumptions for these costs were incorporated into the Company's Strategist modeling.

VI. Review of the Company's Analysis Using the Strategist Model

Q. How did the Company evaluate the proposed wind generation Projects' impacts on its system costs?

A. In addition to evaluating the Projects' LCOE, the Company conducted planning studies using the Strategist resource planning model. Strategist simulates the operation of the NSP System and estimates the total cost of energy over the life of the Projects on a present value basis.

Q. Would you more fully describe how the Strategist model works?

A. Strategist simulates the operation of electric systems for a given planning period. The model calculates the cost of serving a system's demand and energy requirements incorporating any required capacity reserves. Key model inputs include fuel prices, market electricity prices, and current and potential supply and demand side resources. The model, proceeding one year at a time, simulates the dispatch of the system, though it does not specifically forecast each hour, which is a critical limitation that I discuss below. Moving forward through the planning period, Strategist will determine the point at which new resources are needed to satisfy capacity requirements, and will add various combinations of potential new resources and account for the total system costs (capital plus operating) associated with each combination, or portfolio. At the end of the model run, Strategist produces the least cost portfolio.

Q. Do you believe that Strategist is limited in its ability to accurately evaluate the economics of adding 1,550 MW of Wind to the Company's system?

A. Yes. Strategist has limitations, particularly with respect to the evaluation of wind and solar resources. It uses some hourly information; however, it is not a chronological dispatch model. There are two specific limitations of Strategist related to its ability to properly assess the economics of wind and solar generation. The first limitation is related to Strategist's projections of system resources' operations. Rather than solve for the least-cost amount of generation in each hour to satisfy that hour's projected energy requirement, the model employs what is known as a load duration curve methodology. Load duration curves calculate the amount of time in a given month or a given year that a system requires a certain level of capacity. For example, a load duration curve projects the amount of time a system requires at least 10,000 MW of operating capacity, the amount of time the system requires at least 9,000 MW of operating capacity, and so on. By "stacking" available resources in order of lowest operating cost to highest operating cost and overlaying the stack with the load duration curve, the model can quickly estimate the projected operation of each asset until the total system needs are met, beginning with lowest cost resources and incrementally utilizing higher cost resources.

However, in using the load duration curve methodology to determine resource requirements, the model loses precision. By not explicitly projecting operations for each generator in each hour of the study period, as well as generator and transmission constraints, the model tends to understate the operations of higher cost peaking resources, as well as understate the ramping and cycling operations of dispatchable resources. Both of those understatements in turn understate the total system costs related to scenarios with increased amounts of variable energy resources, such as the Wind Portfolio.

The second limitation is that Strategist performs a statistical averaging of the energy attributed to non-dispatchable, intermittent resources such as wind generation. Strategist uses a typical week approach by using a one week sample and repeating that typical week to represent a full month of output. This averaging loses the variability of the maximum and minimum generation of the facility within the month, which again causes the model to understate additional system costs associated with ramping other dispatchable resources to accommodate the intermittent resources.

Q. Given its limitations, do you believe the Strategist analysis is a sufficient indicator of the value of adding the proposed Wind Portfolio to the Company's system?

A. Yes, when transmission congestion, curtailment, and market prices are incorporated as exogenous model inputs. Even while acknowledging Strategist's shortcomings in accurately representing both hourly system loads and intermittent generation facilities, the Company's analysis demonstrates that the proposed facilities will provide significant savings for its customers. Because the proposed facilities' LCOE estimates are lower than the Company's system average cost, I believe the facilities will still represent savings to the Company's customers under a reasonable range of market conditions.

Q. Did you review the Company's Strategist modeling?

A. Yes. Specifically, I reviewed the following:

- The results of the planning scenarios the Company conducted via Strategist;
- The representation of each specific Project's cost and operating characteristics in the model; and
- The representation of the Company's natural gas and market price projections in the model.

Q. Would you please summarize the scenarios that the Company evaluated using Strategist?

A. Yes. The Company developed scenarios that it labeled "Markets On" and "Markets Off". Markets On refers to the assumption that the Company is a member of MISO and can buy and sell electricity from and to the MISO market, while Markets Off assumes a closed utility system. In Markets Off, the Company ran cases where excess energy production has value and does not have value. The Company also ran a "Low Gas" case with the Markets On assumption. The Company also prepared a number of sensitivity analyses assuming 30- and 20-year lives for the turbines, plus and minus five percent capacity factors, and low and high ongoing operating costs. However, those six cases were prepared under the Markets Off scenario.

Q. Do you consider the scenarios the Company developed and analyzed to be reasonable?

A. Partially. Testing the Wind Portfolio's cost-benefit sensitivity to changes in natural gas prices is highly appropriate. However, the Markets Off scenario cases are not as appropriate given that in reality, the NSP system does operate within the MISO market and is therefore not a closed system in terms of generation dispatch to serve system load and resulting market prices. In the Markets On scenario cases, a key assumption is the MISO market prices. In addition to natural gas price sensitivity, it is also important to consider how adding significant amounts of wind and solar generation would impact market prices.

Q. Do you consider the Markets Off scenario cases to be relevant for this Commission to consider?

A. No. My understanding is that the Markets Off scenarios were developed for the MPUC. I do not believe it is appropriate to ignore the reality that NSP participates in the MISO market, and presumably will do so for the life of the proposed Projects. However, the change in savings between some of the Markets Off scenarios provides some insight into the range of potential savings estimates.

Q. Did you review the Company's representation of the Projects in the Strategist model?

A. Yes. I reviewed the individual Projects' revenue requirements for the self-build and BOT Projects and the pricing for the two PPA projects. I also review projected production for all Projects.

Q. What did you conclude regarding the Company's representation of the Projects in the Strategist model?

A. I found the representation to be reasonable. I checked the Company's revenue requirements model for the Self-Build and BOT Projects and confirmed that the revenue requirements were accurately represented in the Strategist inputs for those Projects. For the PPA Projects, I confirmed that the PPA price in the Strategist modeling matched each given bid's price. For all Projects, the total generation projected in Strategist reflected the given Project's expected capacity factor.

Q. Did you review the representation of the Company's system in the Strategist model?

A. Yes. I reviewed the following information related to the Company in the Strategist model:

- The Company's peak demand and energy forecast;
- The representation of the Company's financial assumptions; and
- The fuel and market price projections that the Company assumed in the model.

Q. What did you conclude regarding the representation of the Company's system in the Strategist model?

A. The representation of the Company's peak demand and energy forecast is appropriate given the Company's discussion of the derivation of that forecast.[5] Further, I believe the Company's financial assumptions such as the Weighted Average Cost of Capital ("WACC"), inflation rate, and tax assumptions are consistent with those assumptions identified in the Company's Application and recent Resource Plan.

Q. What did you conclude regarding the representation of the Company's natural gas and market price projections in the Strategist model?

A. In Section IX, I discuss my evaluation of the reasonableness of the fuel and market price projections. My review of the Strategist model concluded that the representation of those projections in the model was reasonable.

VII. Analysis of Congestion Costs and Curtailment Risk

Q. Did the Company include any estimates of congestion costs?

A. Yes. Congestion costs were developed by the Company's Transmission Planning group from PROMOD Locational Market Pricing ("LMP") simulations for years 2020 and 2025 using the MTEP 16 database. The levelized value of congestion for the entire Wind Portfolio was \$3.26/MWh.[6] The levelized congestion value differed slightly by Project and the Company included these values in addition to a separate calculation of the LCOE for each Project based upon revenue requirements, wind integration costs and wind induced coal cycling costs are included as part of the total PVRR Levelized Costs Analysis.

---

[5] The Company's Fall 2016 Load Forecast was included in the Application, along with a discussion of what had changed from the Company's previous Fall 2014 Load Forecast, which was used in the 2016-2030 Upper Midwest Resource Plan.

[6] Advanced Prudence – 1,550 MW Wind Portfolio Application, Table 3, p 41

Q. Did you assess the reasonableness of the Company's congestion estimate?

A. Yes. I reviewed the nodal prices that resulted from the Company's PROMOD analysis, analyzed historical real-time prices for those existing MISO pricing nodes that I determined to be representative proxies of pricing at the interconnection points for each Project, and conducted a load flow analysis to develop a general understanding of how current congestion patterns will change with the addition of the Projects and the completion of major transmission projects.

Q. What were you able to determine based on your review of the nodal prices?

A. Historically, the overall difference between the average of the proxy nodes and the load node have been on the order of [TS]/MWh, and that difference is the total of both congestion and loss components.

Q. How did you go about selecting "proxy nodes" for your analysis of historical pricing and congestion?

A. Based on the specified interconnection points for each of the Projects, I first identified a number of candidate proxy nodes for each of the Projects based on both geographic and future "electric" proximity after planned transmission upgrades enter service. For each Project, I analyzed the congestion and marginal loss components for the candidate proxy nodes to determine if there were dramatic differences in either the average values or their patterns. Because there was relatively little difference in the average congestion and marginal loss components within a candidate group, the selection was straightforward. I utilized real-time price data covering the 18-month period from January 2016 through June 2017.

Q. What proxy nodes did you identify for each Project?

A. The proxy node for each Project is shown below in Table 4.

Table 4. Project/Proxy Node Match

Project	Proxy Node
Foxtail	Tatanka
Crowned Ridge	Big Stone
Lake Benton	Buffalo Ridge
Clean Energy #1	Stanton
Blazing Star I	Blue Lake
Blazing Star II	Blue Lake
Freeborn	Crystal Lake

Q. How did you utilize the historical data to evaluate the reasonableness of the Company's estimate of future congestion?

A. First, I started with the assumption that MISO transmission capacity additions will increase transfer capability and reduce congestion between high wind resource regions and load centers. Hence, recent historical congestion patterns represent a base, or worst case representation of likely future congestion once the current tranche of MVP and CapX2020 transmission projects are fully in-service.[7] To develop a picture of historical congestion, I first characterized the average basis, or price difference, between each proxy node and the NSP load node ("NSP.NSP"). Next, I evaluated how the overall LMP basis was affected by differences in the congestion and marginal loss components of LMPs.

Q. What did your analysis of historical data indicate regarding the difference in LMPs between the wind Project proxy nodes and the NSP load node?

[7] MVP is a portfolio of transmission projects that MISO identified as Multi-Value Projects because they provide significant reliability and economic benefits. The CapX2020 plan is an 11-utility plan to build new transmission lines in Minnesota, North Dakota, and South Dakota, and Wisconsin.

A. As I noted above, I focused my analysis on real-time prices over the recent past (January 2016 through June 2017). Over that period, prices at the proxy nodes have averaged between 3.1 percent and 12.8 percent below prices for the NSP load node. Prices for each of the wind Project proxy nodes and the NSP load node are shown on page 2 of Exhibit JAH-2.

Prices for all of the nodes, including the NSP load node, reflect substantial congestion. However, the difference in congestion value is relatively modest, ranging from -$4.48/MWh at the Freeborn proxy node to -$3.42/MWh for the NSP load node, for a spread of $1.06/MWh. Prices also reflect relatively large marginal loss components. Additionally, in this case, differences in the marginal loss component are actually greater than the differences in the congestion component. Marginal losses range from -$3.08/MWh for the Clean Energy #1 proxy node to -$1.35/MWh for the NSP load node, for a spread of $1.73/MWh. The large difference in marginal losses reflects the fact that the Clean Energy #1 Project will be located relatively distant from the Company's load, while the NSP load node is the closest to load.

Q. Why is it important to understand the relative contribution of congestion and marginal losses to the overall difference in prices between the wind Projects and NSP load?

A. Once fully in service, the proposed MVP and CAPX2020 transmission will have a substantial impact on overall congestion across the NSP and Iowa MISO zones. However, the increased transfer capability resulting from these Projects will not significantly alter the patterns of marginal losses across the region. Hence, we would expect there to be little change in the marginal losses for the wind Projects and the NSP load node over time. Since the average marginal losses account for approximately two-thirds of the difference in prices between the NSP load node and the Wind Portfolio, there will still be a difference in prices as shown in Exhibit JAH-2. Hence, that portion of the historical price difference can be expected to remain in the future.

Q. How do the Company's projections compare to the historical data?

A. As I noted above, prices at the wind Project proxy nodes have averaged 9.6% below those for the NSP load node. The Company's projected values for the difference between the prices NSP load pays and the average for the Wind Portfolio to start at **[TS]**/MWh in 2019, escalating at inflation thereafter. The 2019 price difference represents approximately **[TS]** of NSP's projected 2019 prices, which would indicate that NSP is only projecting a slight reduction from the observed historical differences in LMPs. This is a conservative estimate given the substantial transmission additions that are projected to enter service over the next several years.

Q. Do you conclude that the Company's curtailment estimate is a reasonable assumption?

A. Yes. I conducted two analyses to satisfy myself that the Company's estimates were reasonable. Since wind generation projects in MISO are treated as a Dispatchable Intermittent Resources ("DIR"), I analyzed the distribution of historical prices at each of the Project proxy nodes. In addition, I conducted a forward looking load flow analysis to determine if the Projects would be subject to substantial future congestion created by transmission overloads.

Q. What was the result of your analysis of historical prices?

A. I found that there were relatively few hours when real-time prices at the proxy nodes were below zero and even fewer hours when they were below the negative value of the PTC (i.e., when the PTC no longer offsets the negative price amounts). The Freeborn proxy node had negative prices for 7.0 percent of the hours between January 1, 2016 and June 30, 2017. For the other Projects, the number of negatively-priced hours ranges from a low of 2.5 percent to a high of 3.4 percent. The nodes experienced negative prices below the PTC threshold in less than 1.0 percent of hours. These results are summarized on page 1 in Exhibit JAH-2.

Given expected transmission expansion, I conclude that the company's curtailment estimate of 4% is reasonable, and possibly conservative, given that wind Projects would be expected to generate at prices above the PTC threshold.

Q. How was the load flow analysis conducted?

A. First, available data associated with the transmission interconnections of the eight proposed wind Projects were reviewed. Next, each Project was located on transmission system maps. The MSIO base case power flow was reviewed with a focus on the general transmission system configuration around the project nodes and loading in the vicinity of each project and its relationship to NSP load centers. This subjective review was informed by reference to MISO Transmission Expansion Planning ("MTEP") reports and other MISO studies conducted over the past several years.

Following the subjective review, the Projects were modelled in an Eastern Interconnection Reliability Assessment Group ("ERAG") / Multiregional Modeling Working Group ("MMWG") power flow case representing summer peak conditions for 2025 using PowerWorld Simulator. The model included known transmission system upgrades in the applicable area, including those identified for the Projects. Known generating unit retirements were also modeled.

The output for the Projects were initially set to zero, and were then controlled by Simulator's Available Transfer Capability ("ATC") module to increase generation until overloads or voltage violations were found. Numerous cases were modelled involving various sinks and alternative dispatch patterns for thermal generation in the NSP MISO zone. In addition, a high-wind case was modelled, wherein all wind generation in the Dakotas, Minnesota, and Wisconsin was increased from an average of about 45 percent of nameplate rating to an average of 70 percent of nameplate rating. The NSP zone was designated as the sink for the generation from the wind Projects.

While these cases represent only a small portion of the possible dispatch scenarios, they are adequate to identify likely constraints and their severity. In particular, the constraints identified are generally consistent with known system constraints, many of which have been considered for relief either in conjunction with proposed generation projects which have subsequently been canceled or as economic projects.

Q. What was the result of the load flow analysis?

A. The various scenarios modeled resulted in similar constraints, though at differing generation levels. I consider the reduction of all NSP thermal generation as the most realistic, and it resulted in the highest transfer capability. In the modeling cases where the thermal generation was not redispatched to relieve any constraints, there were instances of 115 kV or 230 kV lines overloading for the outage of a 345 kV line. However, it was relatively easy to dispatch around those constraints by adjusting the generation from various thermal units that were upstream from the constraints. Nearly all of the potential overloads observed would most likely be resolved by reconductoring short sections of lines, or with other relatively low cost solutions. The same overloads occurred in the high wind (i.e., worst) case, typically at somewhat lower output levels for the Wind Portfolio. However, again it was possible to redispatch thermal generation to allow the Wind Portfolio to generate at its maximum total output.

By demonstrating that it will be possible to dispatch around the identified constraints, the results of the load flow analysis are consistent with Company's findings, and both sets of results are generally consistent with observed historical real-time price behavior. Further, the observed constraints are mostly included in the MISO Northern Area Study of 2013, which MISO continues to monitor. As more wind comes online in the Dakotas, transmission projects to relieve these constraints are projected to have improving benefit/cost ratios and thus become more compelling for inclusion in MTEP, if they are not constructed in conjunction with specific wind projects.

VIII. Analysis of the Projects as Dispatched into the MISO Market

Q. How will the wind Projects earn revenues in the MISO market?

A. The Projects will earn revenues based upon dispatching against the clearing price in the MISO market. The market clearing price will reflect congestion and losses allocated to each generator's interconnection node. In most hours, wind units are essentially price takers since they have virtually zero SRMC with the exception of the PTC, which incents them to generate even if market prices are negative.

The same concept is true for the Company's thermal generation - if the SRMC of the generators is below the market price, then in most instances the generators should be dispatched. The implication is that in hypothetical situations where adding the 1,550 MW of Wind does not change market prices, the Company's thermal units will still dispatch and there are not technically fuel savings from adding the wind units, but instead there are increased revenues from market sales. However, MISO dispatches generation to meet load. Therefore, if new lower cost generation is added and dispatched into the market, then what was the marginal unit will either have to reduce generation or will not run, and a lower cost unit will set the marginal price. Depending on the amount of generation added, the load at a given hour, and the slope of the dispatch curve, the price adjustment could be very small or could be significant.

Q. What are the implications of dispatching into the MISO market with respect to evaluating the savings from the Wind Portfolio?

A. The savings to customers can be estimated by the forecast of revenues from market sales less the forecast of the costs of the Projects. Under this valuation framework, the

Strategist analysis using the Markets On logic becomes a very complex tool to perform a relatively simple calculation. The market revenues from the Wind Portfolio are the product of the generation times the forecast of market prices.

Q. Have you performed a calculation of the savings based upon a forecast of market prices?

A. Yes. I calculated the market revenues based upon the hourly production profile of each Project, summed into on- and off-peak generation by month, and multiplied by the on- and off-peak MISO forecast of Minnesota Hub prices provided by the Company with an associated adjustment for congestion. I included capacity revenues based upon the MISO Market Monitor's estimate of the net Cost of New Entry ("CONE") and subtracted the Company's estimates for renewable integration and coal plant cycling costs.[8] I then calculated the annual savings based upon the revenue requirements prepared by NSP. This calculation is shown in Exhibit JAH-3

Q. What are the estimated savings?

A. The estimated net present value of savings for the base case are $1,417 million. This estimate of savings is approximately 11% lower than the Company's estimate.

Q. Is this approach to estimating Project revenues consistent with how investors evaluate investments in power generation projects in the MISO market?

A. Yes, at a high level. However, investors are typically interested in understanding hourly price patterns versus monthly average on- and off-peak prices. In addition, investors

---

[8] Net CONE estimate from *MISO Competitive Retail Solution Responses to Stakeholder Input and Questions*, The Brattle Group, October 6, 2016.

focus on how the forecast of market prices was developed to evaluate the reasonableness of the market price forecast.

Q. Does the Strategist model create the forecasts of the market prices?

A. No. The market prices are an exogenous input to Strategist. The market prices prepared by the Company would have either been purchased from a third party vendor or developed internally with a different model. In this instance the Company indicated that the market forecast is based upon the Intercontinental Exchange prices for the short term and a blend of three long-term fundamental forecasts from Wood Mackenzie, Cambridge Energy Research Associates ("CERA"), and PIRA.[9] Strategist uses the market prices to determine whether the market or NSP generation should be used to meet the utility's load and to calculate revenue and costs associated with market energy sales.

Q. Are the market electricity prices impacted by natural gas prices?

A. Yes. When natural gas-fired generation units are the marginal units setting market prices, there is a strong relationship between gas prices and power prices. The MISO Market Monitor reports that over the last 13 months, the correlation coefficient between the Henry Hub natural gas price and the MISO RT LMP was almost a 0.77.[10]

Q. How does the forecast of natural gas prices compare to historical prices and other forecasts?

A. The natural gas price forecast appears reasonable. Figure 1 shows the historical Ventura gas hub prices and the Company's forecast used in the analysis, as well as the Energy

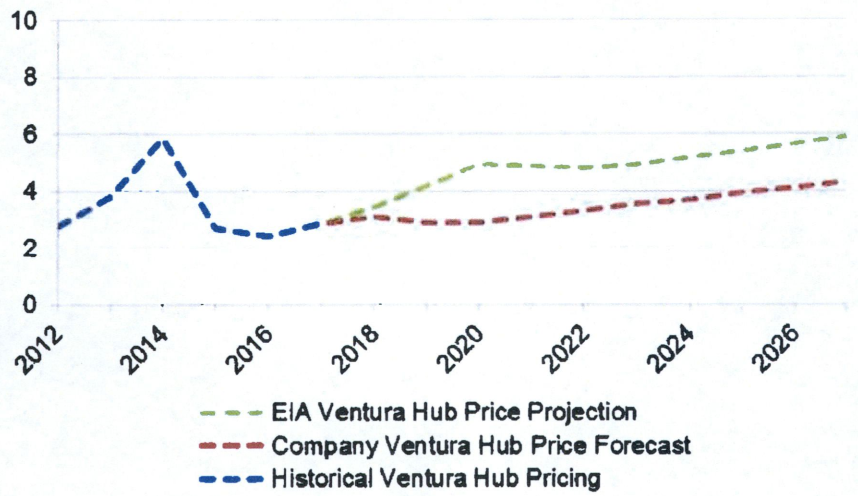
---

[9] Exhibit PJM-1 Schedule 3 p 7.

[10] MISO May 2017 Monthly Market Assessment Report, Market Evaluation and Design, July 13, 2017, p 17.

Information Administration's ("EIA") forecast for comparison[11]. Though the EIA forecast experiences a substantial increase relative to the Company's forecast between 2018 and 2020, beyond that period the two forecasts increase at nearly the same rate. In general, lower gas prices will tend to reduce the value of the energy cost savings of the proposed wind Projects, and given that the Company's forecast is approximately $2/MMBtu lower than the EIA forecast, I believe the forecast is reasonable.

Figure 1. EIA Natural Gas Price Forecast vs. NSP Forecast ($/MMBtu)



Q. How does the forecast of market power prices compare to historical prices?

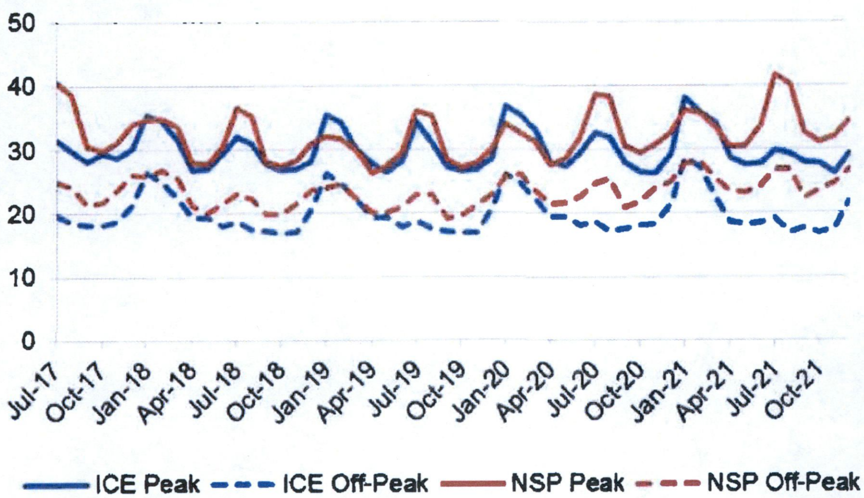
A. Because market power prices are highly correlated to natural gas pricing, the 2012-2016 power prices followed a similar pattern to natural gas prices, with power prices having risen in the 2013-14 timeframe, followed by a sharp decline in 2015 and a small increase since then. For the purposes of this evaluation, I noted that the 2015-16 prices were the lowest of the five year period.

[11] The EIA forecast was created using EIA's Reference Case Henry Hub forecast, to which PA Consulting's estimate of basis differential and transport costs were added to project the Ventura Hub forecast.

Q. How does the Company's forecast of market power prices compare to current forward prices?

A. The current on-peak forward prices are approximately $2.25/MWh below the Company forecast and the off-peak forward prices are approximately $3.45/MWh below the Company forecast.[12] This is illustrated in Figure 2.

Figure 2. Current MIN HUB Forwards versus NSP Forecast ($/MWh)



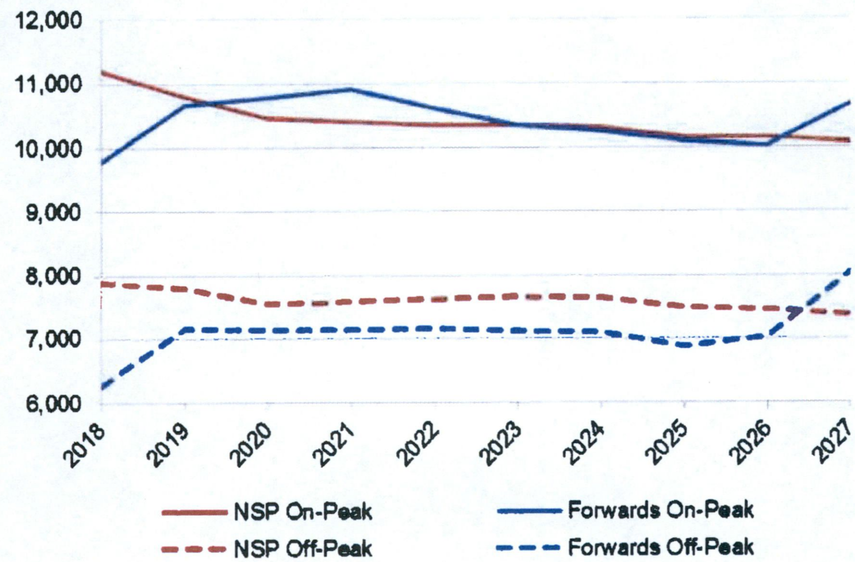
Q. Does the Company's market power price forecast appear reasonable based upon the calculated market heat rate?

A. I calculated monthly on- and off-peak market heat rates using the monthly market price and gas price forecasts used by NSP as inputs to Strategist, and did the same using the forward market power price and natural gas price forecasts. The analysis revealed that

[12] Forwards as of July 13, 2017 for the Minnesota Hub as reported by ICE https://www.theice.com/marketdata/reports/142

through 2027, the Company's implied on-peak heat rates were either lower than, or generally equal to the forward market implied heat rates, suggesting the Company's numbers aligned with the market. The Company's off-peak implied heat rates are consistently higher than the forward market off-peak heat rates, which will tend to overstate the wind Projects' energy cost savings. This comparison is shown in Figure 3.

Figure 3. Market Heat Rate Forwards versus NSP Forecast (Btu/kWh)



Q. Did you estimate how the revenues from the Wind Portfolio would change under different market power price scenarios?

A. Yes. I evaluated the proposed Wind Portfolio under a variety of market power price scenarios. In particular, to project the revenues in a low natural gas price scenario, I used the Company's low natural gas cost assumptions and projected the corresponding monthly market power prices using the Company's base case implied heat rates. I also developed a scenario based upon a drop in the market heat rate that would result from higher penetration of wind and solar generation.

Q. What are the estimated savings based upon the different market power price scenarios that you developed?

A. The results are shown below in Table 5. The sensitivity analyses are intended to be indicative of downside performance. I would expect the actual results to differ had I developed new market prices with an hourly chronological dispatch model.

Table 5. Market Price Sensitivity Analyses

Scenario	Estimated Savings $ (Millions)	% Decrease in Savings	Description
Base Case	1,417		
Low Gas Case	783	(44%)	Company low gas prices
Higher Renewable Penetration	887	(37%)	Months with on or off-peak market heat rates in excess of 7,000 capped at 7,000. Months with heat rates below 7,000 remain unchanged.
Higher Renewable Penetration and Low Gas Prices	372	(73%)	Combined assumptions from the low gas and high renewable penetration assumptions.

Q. Is it likely that market power prices will decrease to the point that these Projects are not economic?

A. I do not think it is likely, since the market power prices would have to drop below the levelized cost of the Projects. Even at a long-term average market heat rate of 7,000 Btu/kWh and $3/MMBtu natural gas, these Projects will be cost effective based upon the revenue requirements that the Company has calculated.

IX. Economic Analysis

Q. Did you review the Company's economic analysis of the levelized cost of the Projects and the estimated electricity cost savings to ratepayers?

A. Yes, I reviewed the individual spreadsheet models provided by the Company as well as the ratepayer savings analysis that is based upon the Strategist model runs. My conclusion is that the spreadsheet models were developed correctly and that the reported levelized costs are consistent with the models. Of course, these results are based upon a number of critical assumptions. I previously discussed the assumptions related to natural gas costs, wholesale market power prices, and congestion costs. In this section of my testimony, I review additional assumptions, including: the cost of capital, Project lifetime, Project output, wind integration costs, capacity costs, O&M costs, and the PPA pricing.

Q. Do the levelized cost and revenue requirements models include wind farm decommissioning costs?

A. No. I reviewed the Company's spreadsheet models and did not identify a capital expenditure or increase in O&M at the end of 25 years to cover decommissioning costs.[13]

Q. If decommissioning costs were excluded, is it your expectation that it would change your recommendations regarding approval of the ADP?

A. No. I assume a cost of $50,000 (in real terms) per turbine at the end of the 25-year period as the decommissioning cost, net of salvage value. This increases the levelized cost of the Projects on the order of **[TS]**/MWh.[14]

Q. Did the Company use an appropriate discount rate in calculating the present value of savings and the levelized cost?

---

[13] Confidential responses to 16-077 DOC-010 Attachments B,C,G,H & I

[14] Decommissioning cost estimate based upon the New York Black Oak Wind Farm Decommissioning Plan.

A. Yes, the discount rate is appropriate. The Company used a [TS] percent discount rate in the levelized cost calculations for Company-owned Projects and a 5.833 percent discount rate for PPAs.[15] The [TS] is the after tax WACC. A [TS] percent discount rate is hard coded into the spreadsheet models even though the Company calculates a before tax WACC of [TS]. The discount rate is based upon the capital structure and return assumptions in Table 6.

Table 6. Cost of Capital Assumptions

Component	Structure	Return	Before Tax WACC
L-T Debt	[TS]	[TS]	[TS]
Common Equity	[TS]	[TS]	[TS]
S-T Debt	[TS]	[TS]	[TS]
Total			[TS]

The NSP Return on Equity ("ROE") assumption of 9.2 percent is below the average ROE of 9.77 percent awarded in 42 electric rate cases in 2016.[16]

Q. What Project lifetime is assumed in calculating the present value of savings and the levelized cost of the Wind Portfolio?

A. The savings calculations for the two PPAs use the life of the contracts, while the owned wind farms assume a 25-year life in the Company's base case. However, the Company also ran sensitivity analyses with 20- and 30-year Project lives. The 20-year life reduced

---

[15] See 16-0777 DOC-010 Alt B...Alt I in the tab "Levelized Cost".

[16] SNL Rate Case Statistics, https://www.snl.com/interactivex/RateStatistics. According to SNL Rate Case Statistics the MNPUC authorized a ROE of 9.72% in the last rate case.

the savings by approximately 18 percent.[17] I conducted an independent analysis and also calculated an 18 percent reduction in savings.

Q. What is an appropriate Project life to use?

A. PA routinely reviews wind energy projects to help investors obtain financing. The 25-year assumption is commonly used in the industry. However, I am also aware that some research and experts suggest a 20-year life.[18] Therefore, my conclusion is that while 25 years is common, the consideration of benefits based upon a 20-year life is also a reasonable conservative assumption.

Q. How is the capacity of the wind Projects valued in the economic analysis?

A. The spreadsheet financial models address costs and not revenues. The value of the capacity is embedded in the Strategist analysis.

Q. Does the economic analysis include any assumption regarding wind integration costs?

A. The summary of the levelized cost of each individual Project does not include wind integration costs. However, the Company provides an estimate of \$0.53/MWh - \$0.56/MWh depending on the Project.[19] The wind integration costs, transmission congestion costs, and coal plant cycling costs are included in the Company's analysis of

---

[17] Advanced Prudence – 1,550 MW Wind Portfolio Application Tables 1 & 2 pp. 38-39. Reduced savings based upon comparing the case of Markets off Dump Energy Credit (\$1,541M savings) with Markets Off 20-Year Life (\$1,269M savings)

[18] For example, a project design life of 20 years was the default baseline value in a survey of experts related to calculating the LCOE of onshore wind. Forecasting Wind Energy Costs and Cost Drivers: The Views of the World's Leading Experts, Wiser et al, LBNL-1005717.

[19] Advanced Prudence – 1,550 MW Wind Portfolio Application, Table 3, page 41.

the impact of the Projects on North Dakota's revenue requirements and in the savings estimates.[20]

Q. What is the basis for the wind integration and coal plant cycling cost assumptions?

A. The Company uses its 2015 Wind Integration Study provided as part of its Upper Midwest 2016 – 2030 Resource Plan.

Q. Are the wind integration cost assumptions reasonable?

A. Yes, they appear reasonable. I am aware of a number of studies that attempt to quantify the costs and understand that estimates vary and are also a function of the penetration of intermittent renewables, the overall generation mix, and the size of the power market. In addition to reviewing the Xcel 2015 Wind Integration Study, I also reviewed a summary of other studies which indicates that most estimates are in **[TRADE SECRET]** range.[21]

Q. Did you evaluate the impact of changes in production as a result of curtailment or deviations from expected performance?

A. Yes. The Company evaluated the impact of a five percent change in capacity factor using the Markets Off scenario and identified that it would result in a $537 million decrease in savings if the capacity factor drops by 5 percent, and a $146 million increase in savings if the capacity factor increases by 5 percent. I attribute the asymmetrical adjustment to the Markets Off scenario. I assume that the Strategist model is either using the excess wind production to back down thermal generation and reduce fuel purchases, or dumping the electricity if the thermal generation cannot be backed down. In the model, dumped energy is assigned a value of 50 percent of the market LMP. I assume that in most

---

[20] Advanced Prudence – 1,550 MW Wind Portfolio Application, Table 5, page 42.
[21] 2015 Wind Technologies Market Report, U.S. Department of Energy, August 2016, p 73.

instances under the Markets Off scenario, the increased wind generation assumption results in burning less fuel, and that is what is reflected in the savings.

I took a different approach to modeling the five percent change in capacity factor. While a slightly idealized assumption, I assumed that a five percent change in output from the Wind Portfolio is small enough to not move the MISO market price. Therefore, whatever Company thermal generation units were profitable to dispatch into the market will continue to be profitable. Therefore, a five percent change in output results in a five percent change in the revenues that the Wind Portfolio will receive when it is dispatched into the MISO market. This logic results in a five percent adjustment, increasing or decreasing the Wind Portfolio savings by $146 million.

Q. Are the congestion cost assumptions reasonable?

A. Yes. As I explained earlier in this testimony, the results are reasonable based upon analysis developed by PA and other studies.

Q. Did you review the O&M cost assumptions incorporated into the estimate of savings?

A. Yes. I reviewed the costs for each Project and compared those costs to average costs reported in a 2016 National Renewable Energy Laboratory ("NREL") study.[22] While the Project O&M costs are above the average reported in the study, the study noted that their survey of costs was difficult to validate. A summary of the O&M costs is shown below in Table 7. I averaged four years of costs, expressed in 2015 dollars, to develop an average Project O&M cost. I also noted that NSP developed a sensitivity analysis where O&M

[22] 2015 Cost of Wind Energy Review, Mone, Hand, et al., National Renewable Energy Laboratory, March 2017.

and maintenance CapEx is increased and decreased by ten percent and the ongoing maintenance CapEx is adjusted by 30%.

Table 7. Summary of O&M costs

Project	2015 $/kW Average O&M
Blazing Star I	[TS]
Blazing Star II	[TS]
Crowned Ridge	[TS]
Foxtail	[TS]
Freeborn	[TS]
Lake Benton	[TS]
NREL Study	[TS]

Q. Did you evaluate how a ten percent increase in O&M costs would impact the estimated savings?

A. Yes. I noted the Company's estimate that a 10 percent increase in O&M and 30 percent increase in ongoing CapEx costs would decrease savings by $64 million.[23] I also completed an independent analysis using the individual Project models and calculated decreased savings of $57 million. As a downside sensitivity, I consider either number to be a reasonable estimate.

Q. Does the economic analysis include any valuation of environmental or economic development benefits?

A. No, neither environmental nor economic development benefits are incorporated into the estimated savings to ratepayers or levelized cost analysis. My understanding is that exclusion of these two items is consistent with North Dakota statute.[24]

---

[23] See Table 2 of Martin Direct p 45 scenario "Mkts Off Dump Energy Credit" and Table 3 of Martin Direct p 48 scenario "Mkts Off High On-Going Costs.

[24] *See* N.D.C.C. § 49-02-23.

Q. What are your conclusions with regards to the Company's estimate of $1,599 million of savings from the Wind Portfolio?

A. My conclusion is that the Projects will result in electricity cost savings to North Dakota customers. I propose some adjustments to the Company's savings estimate to reflect a more conservative view. However, directionally, my results do not differ from the Company's analysis. These adjustments are shown below in Table 8.

Table 8. System Wide Estimated Savings

Component	Savings (adjustment)	Comment
Base Case Estimate	$1,417 million	Markets On Base Case
Project Life Adjustment	($290 million)	20-year conservative estimate
Wind Project Construction and Interconnection Costs	$0	North Dakota customers held harmless for overruns as part of ADP
Adjusted Savings Estimate	$1,127 million	

Q. Have you developed a downside case?

A. Yes. Note that I do not view it as likely that all of the events included in the downside case will be concurrent. However, even if all the events were to occur concurrently, the Wind Portfolio would still be projected to achieve energy cost savings. This scenario is shown in Table 9.

Table 9. Estimated Savings in Downside Scenario

Component	Savings (adjustment)	Comment
Initial Company Estimate	$1,417 million	Markets On Base Case
Project Life Adjustment	($290 million)	20-year conservative estimate
Wind Project Construction and Interconnection Costs	$0	North Dakota customers held harmless for overruns as part of ADP
5% Decrease in Output	($141 million)	Attributable to any number of factors including curtailment and outages
O&M Cost Adjustment	($57 million)	10% higher O&M costs & 30% higher maintenance CapEx
Low Gas Prices	($634 million)	Company low gas prices
Adjusted Savings Estimate	$295 million	This is not an expected value of savings

Q. Have you reviewed the rate impacts associated with the projected savings?

A. Yes. As noted in the Application, rates are projected to initially increase as a result of construction costs, and then start to decrease in 2020 as the wind Projects come online. The estimated monthly impact for residential customers using 750 kWh/month as an average usage estimate will be an increase in the monthly bill of $0.44. However, by 2022, the monthly savings will increase to $0.92/month, with maximum monthly savings in the 2027 period. These numbers differ from what I calculate based upon the revenues of dispatching the Projects into the market less the revenue requirement associated with the Projects. Nevertheless, the savings are similar.

Q. Did you review the pricing of the two PPAs?

A. Yes. The Crowned Ridge PPA price per MWh [**TRADE**]**SECRET**]. The Clean Energy PPA starts [**TRADE SECRET** **TRADE SECRET** **TRADE SECRET** **TRADE SECRET** **TRADE SECRET** **TRADE SECRET**], the cost per MWh is still substantially below the base case forecast of the market cost of power.

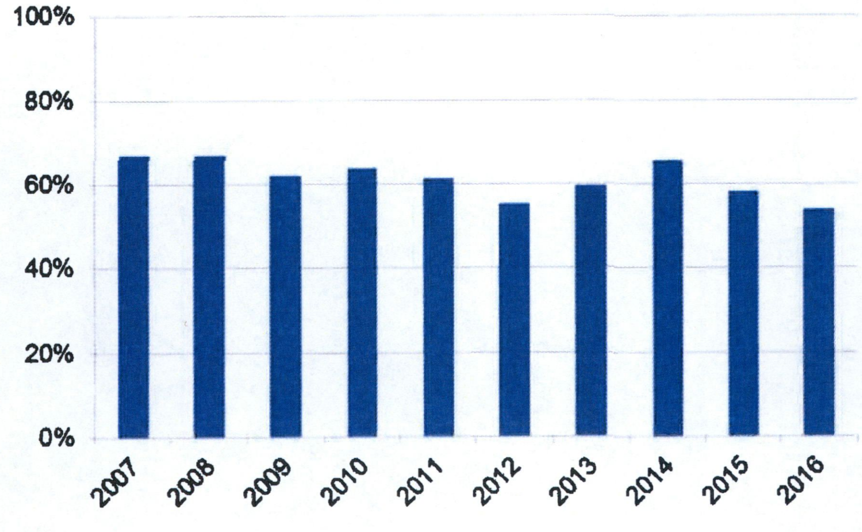
X. Other Issues Considered

Q. Will these Projects increase the cost of power from coal generation in North Dakota?

A. Yes. It is likely that these Projects will contribute to the increased cost of coal generation on a dollar per MWh basis. However, it is difficult to quantify what the specific impact of these Projects will be. Collectively, Minnesota, North Dakota, South Dakota, and Wisconsin have added over 5.8 GW of wind projects in the last decade, and there is an additional 3.8 GW of proposed and permitted wind projects.[25] These projects collectively contribute to a need for coal plants to cycle more, operate less efficiently, and spread fixed costs over fewer MWh generated. As shown in Figure 4, the average capacity factor of MISO coal plants has been in decline over the past decade, with the exception of an uptick in part attributed to a significant cold snap (often referred to as "the Polar Vortex") in December 2013 – January 2014.

[25] Figures for MISO, Energy Velocity

Figure 4. MISO Coal Plants Aggregate Capacity Factor[26]



Q. Has the Company provided an estimate of the increased cost to coal plants?

A. Yes. The Company provided an estimate of $1.48/MWh for "wind induced coal cycling".[27] I reviewed the 2016 study on the impact of wind and solar on the cost of coal plant cycling in the Public Service Company of Colorado (an Xcel Energy subsidiary) system. The scenario with the largest amount of wind added in the northern Colorado region was limited to 900 MW, and the conclusion of the study is that the levelized cycling cost is $1.14/MWh.[28] I also reviewed a 2013 NREL study of the impact of wind and solar on coal plant cycling in the west, and the high cost scenario estimated a cycling cost of $1.28/MWh.[29] Based upon these two studies, I concluded that $1.48/MWh is a reasonably conservative assumption.

---

[26] Source: SNL

[27] Advanced Prudence – 1,550 MW Wind Portfolio Application, Table 3, page 41.

[28] Wind and Solar-Induced Coal Plant Cycling and Curtailment Costs on the Public Service Company of Colorado System, Xcel Energy Services, Inc., May 13, 2016.

[29] The Western Wind and Solar Integration Study Phase 2: Executive Summary, Lew & Brinkman, National Renewable Energy Laboratory, NREL/TP-5500-58798, September, 2013 https://www.nrel.gov/grid/wwsis.html

Q. Is the increased cost of coal plant cycling included in the Company's estimate of the present value of savings to North Dakota customers?

A. Yes, it is incorporated into the Strategist analysis. The analysis only incorporates the cost until 2040, which is the assumed shutdown date of the last NSP coal plant, but other coal plants in the region will not necessarily shut down by that date.

Q. If the Commission rejects the ADP, will the increased coal plant cycling cost be avoided?

A. I do not believe so. Given that the MPUC has approved NSP's application for 1,550 MW of Wind, it is my understanding that the Projects will be constructed regardless of the Commission decision. In addition, as I noted above, there is a large amount of wind that is targeted for construction in addition to the 1,550 MW, which will also impact the coal plants.

Q. Did the Company accept the lowest cost Projects for the Wind Portfolio?

A. I did not conduct an extensive review; however, I believe so. The Company engaged Leidos Engineering, LLC ("Leidos" or the "Auditor") as an independent auditor. The audit began with the development of Request for Proposal ("RFP") documents, continued through the evaluation of proposals, and ended with the final selection of short-list bidders. The main objectives of the audit were to (1) ensure that RFP documents provided sufficient information for bidders; (2) identify and address any potential bias in the evaluation criteria; and (3) verify that the evaluation criteria were applied in a fair manner.

I have reviewed the audit report and the Auditor reviewed the modeling, due diligence, and evaluation criteria used by the Company in its procurement process for the purpose of identifying irregularities, bias, or discrimination which may have been applied during the selection of Projects for the Wind Portfolio. The Auditor found no material issues. The Auditor reviewed the Company's LCOE model and confirmed that it provided a fair and reasonable evaluation of the LCOE of the proposed Projects.

XI. Recommendations

Q. Should the Commission grant an ADP for the proposed wind Projects?

A. Yes, although I recommend that the ADP include the following qualifications:

- North Dakota ratepayers should not have to pay any additional costs if the Company fails to get the full PTC for any of the Projects;
- Recovery of wind Project construction, interconnection, and transmission costs for the four Company self-build Projects should be limited to no more than [**TS]** million in aggregate (adjusted for any Projects not constructed);
- Construction costs for the two BOT Projects should be limited to no more than **[TS]** million in aggregate (adjusted for any projects not constructed);
- A financial incentive to the Company should be created whereby if the Projects collectively are constructed and interconnected below budget, the savings are shared;
- In conjunction with the monthly fuel cost adjustment filings to the Commission, the Company should provide monthly reports of curtailment and negative pricing observations at each of the seven Projects, and any known reasons for observed curtailment and negative pricing; and
- The Company should provide quarterly construction progress reports until the last Project is in service, indicating the development status of each Project.

Q. What are the economic consequences if the Company does not meet the safe harbor requirements for starting construction in 2016 and or meets the target but does not meet the four-year completion requirement under the Continuous Construction Test?

A. In the extreme, if the Projects do not qualify for the PTC, the LCOE increases by approximately 150 percent per Project, as shown in Table 10.

Table 10. Levelized Cost without PTC

Project Name	LCOE with PTC	LCOE without PTC
***** Trade Secret Data Begin		
Foxtail	[TS]	[TS]
Clean Energy #1	[TS]	[TS]
Crowned Ridge	[TS]	[TS]
Lake Benton	[TS]	[TS]
Blazing Star I	[TS]	[TS]
Blazing Star II	[TS]	[TS]
Freeborn	[TS]	[TS]
Trade Secret Data Ends *****		

Q. Why should Company shareholders absorb the full risk of not qualifying for the full PTC?

A. The justification for the 1,550 MW of additional wind is based on the premise that it will lower energy costs for ratepayers. The Company has testified that in both the PPA and BOT Projects, the bidders assume the risk of completing the Projects in time to qualify for the full PTC.[30] The Company also states the following for the Projects that it constructs.

> "We have developed a comprehensive project schedule that involves the sequenced construction of the four self-build projects to keep the projects on track to ensure qualification for 100 percent of the PTCs." [Advanced Prudence – 1,550 MW Wind Portfolio Application, p 44]

[30] Advanced Prudence – 1,550 MW Wind Portfolio Application, p 43

Q. How should the maximum recovery of construction cost for the self-build and BOT Projects be adjusted if one or more Projects does not get built?

A. The costs should be adjusted for the Projects not built by the total costs shown in Table 3 of this testimony.

Q. Why are you recommending that the Company bear the risk of cost overruns related to the Projects' construction and transmission interconnection costs?

A. The company has indicated that it has taken a number of measures to ensure that the Projects stay on budget. These measures include:

- For BOT Projects, the construction risk is assigned to the bidder;[31]
- For PPA Projects, the Company is not obligated to make payments prior to the commercial online date ("COD");[32]
- For self-build Projects, the Company states that it has mitigated the risk through constructing multiple Projects;[33] and
- Transmission interconnection cost risks for BOT and PPA Projects have been mitigated through agreements with each Project's developer.[34]

Since the Company has indicated that it has implemented these procedures for controlling costs, it should assume the responsibility for implementing the measures. Additionally, the customers have no control over these costs and these Projects are not needed but for the Company's commitment to reduce power costs. Finally, if the bidders are held to the construction costs, the Company should also be held to the construction costs.

---

[31] Advanced Prudence – 1,550 MW Wind Portfolio Application, p 44
[32] Advanced Prudence – 1,550 MW Wind Portfolio Application, p 44
[33] Direct Testimony of Chandarana p 25
[34] Advanced Prudence – 1,550 MW Wind Portfolio Application, p 45

Q. Is the MPUC requiring that the Company be held to the construction costs?

A. My understanding is that MPUC Staff have recommended that NSP be responsible for costs higher than what was bid or assumed.[35] At the time of preparing this testimony, a final order from the MPUC had not been made public.

Q. If the Company bears the risk of cost overruns, how should the Commission treat construction and interconnection cost savings?

A. I am proposing a sharing of savings where 60% percent go the North Dakota ratepayers and 40% is retained by the Company. The sharing is intended to provide the Company with an incentive to aggressively pursue cost control. However, I do not recommend that the Company retain 100% of the savings since the Company should be aggressively pursuing cost controls even without incentives as part of its obligation to operate efficiently.

Q. What are your recommendations with regards to reporting?

A. In order for the Commission to be kept current on the construction progress, I recommend that the Company file quarterly reports on the status of the construction of the self-build Projects as well as the BOT and PPA Projects. In addition, in the ongoing monthly fuel cost adjustment reports, the Company should include information about the amount of curtailments and negative pricing, and any available explanation for those curtailments and prices.

Q. **Is it your expectation that the recommended reporting will create a large burden on the Company?**

---

[35] https://www.edockets.state.mn.us/EFiling, Docket 16-777, document ID 20176-133101-01

A. No. My understanding is that the reporting is similar to what the MPUC is already requiring.

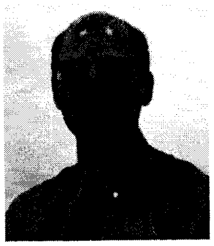
Q. Do you have any recommendations regarding future review of new resource additions?

A. Yes. I recommend that the Commission consider a review process for NSP resource planning to be more proactive in defining the needs of North Dakota customers. My understanding is that NSP files its resource plan in North Dakota but the Commission does not formally review or respond to the plan. I recognize that the Commission has limited resources to review the plans and has limited influence on resource selection since North Dakota constitutes approximately 5-6 percent of the integrated system in terms of sales. However, even if the Commission does not formally approve the plans, I believe it would be appropriate and beneficial for the Commission to provide some formal guidance related to what resource retirements and additions are consistent with the needs of North Dakota

Q. Does this conclude your testimony?

A. Yes.

Jim Heidell



Jim Heidell specializes in electric and gas utility regulation, utility finance, wholesale electricity markets, evaluation of renewable energy technologies and financial analysis of complex investments. Mr Heidell assists clients with due diligence associated with acquisition of natural gas and electric utilities and wholesale energy market transactions. Mr Heidell has prepared and submitted testimony in both regulatory proceedings and civil contract damages cases. Mr Heidell also specializes in strategic analysis and evaluation of opportunities associated with renewable / alternative energy technologies. .

Primary expertise

- Electric and natural gas utility regulation and finance
- Analysis of wholesale electric markets
- Renewable Energy Technologies
- Asset valuation / M&A Advisor
- Damages estimation for civil litigation

Related experience

- Strategic planning
- Financial modelling of complex investments
- Financial planning

Qualifications

- 30-years' experience with electric & gas utilities and electricity markets
- MBA University of Washington
- MSE Engineering Economics, Stanford University
- BSE, Civil Engineering, Tufts University
- CFA

Primary expertise

Utility Regulatory Support - Prepare expert testimony in regulatory hearings related to resource acquisition, QF issues, rate impacts, marginal and embedded cost of service, and rate design. Developing marginal and embedded cost studies for regulated utilities.

Renewable Energy Technologies - Develop business plans, market positioning strategies, and financial analysis of renewable technologies including PV cell manufacturing, flywheels, and fuel cells along with renewable generation technologies including solar thermal, geothermal, wind, battery storage, and IGCC projects.

Analysis of Electric Markets - Develop energy and capacity forecasts for U.S. power markets to support: strategic investments by utilities and major energy companies, development of utility risk management strategies, and corporate strategies for generation asset acquisition and disposition.

Asset Valuation / M&A Advisor - Provide valuation advice for acquisition of electric generation portfolios, single power plants, transmission projects, electric utilities, and gas distribution companies. Work also included review of wholesale and retail regulatory pricing mechanisms and analysis of associated risk.

Damages Estimation for Civil Litigation Testimony - Prepare expert witness testimony to support power contract litigation, property tax cases, power plant development agreements, and quantification of economic damages.

Financial Analysis - Long-term modelling of utility finance. Analysis of major capital investments using a variety of tools to incorporate uncertainty and risk.

Key client achievements

UTILITY REGULATORY SUPPORT

Analysis and testimony on behalf of Constellation Energy Group related to typical merger and acquisition conditions required by regulators in utility and non-utility transactions. Testimony related to the EDF / Constellation joint venture.

Testimony related the use and design of ratchet rates on behalf of Northern Indiana Public Service Company. Testimony related to the application of ratchets to the client's unique position and appropriate recovery of costs.

Analysis of the economics of an electric utility's interruptible rates including the value of interruptions versus the payments received by customers. Developed recommendations for pricing interruptible rate programs that were consistent with the utility's avoided costs and ISO markets.

Developed electric cost-of-service studies, rate design, and testimony to support Puget Sound Energy in multiple general rate cases in Washington. The engagements included addressing issues such as special rates for strategic customers with competitive options, line extension policies, and rates to address revenue attrition.

Developed natural gas cost-of-service studies, rate design, and testimony to support Puget Sound Energy in a general rate case in Washington.

Prepared marginal cost of service studies and testimony to support Montana-Dakota utilities in multiple Montana rate cases.

Assist Montana-Dakota Utilities in development of its integrated resource plan through analysis of options using the Strategist planning model.

Supported Montana-Dakota Utilities in answering a complaint in front of the South Dakota Public Utilities Commission regarding a wind generator requesting a contract under the provisions of PURPA.

Provided expert testimony related to Montana Dakota's proposed participation in the Big Stone II power plant. Prepared and delivered testimony provided in multiple hearings in North Dakota and Minnesota.

Prepared testimony on behalf of Hydro One Networks regarding rate shock and how to address necessary rate changes associated with the restructuring of the electric utility business in Ontario.

Developed an analysis or weather risk associated with the retail power sales of IPALCO. Effort was conducted as part of a comprehensive risk assessment conducted by AES. Models of the weather / load relationship were developed and then integrated with the rate structures and cost adjustment mechanisms to assess the utility's overall exposure to weather risk.

Advised Old Dominion Electric Cooperative on options for acquiring new generation in a depressed power market and incorporation of the analysis in their long-term resource planning.

MEXICO ENERGY MARKET REFORM

Developed rate proposals for PEMEX SDC tariffs for transportation, conditioning and storage of oil and natural gas. The rate proposals were the final stage of a project that started with benchmarking tariff structures in key markets worldwide, development of business considerations, development of appropriate cost of service and rate design principles, preparation of a revenue requirement, development of a cost of service model and study, and development of proposed rates for the PEMEX services.

Developed long-run electricity price forecasts multi-national energy companies reflecting the rules of the reformed market. Price forecast based upon an hourly chronological dispatch model.

Delivery of a workshop for rate design for CFE transmission. Review of distribution and transmission revenue requirements for CFE and analysis of financial implications of energy reform on CFE.

ELECTRIC MARKETS RISK MODELING

Advised major European trading company on entering the U.S. electricity trading business. Project included selection of target markets, characterization of types of trading opportunities, characterization of market volumes, identification of target customers, review of key licensing requirements, and development of a high level business strategy.

Provided support to a bond insurance company to prepare an assessment of the distribution of income from a fleet of peaking power plants in the South-East. Analysis used to review the provision for loss reserves.

Supported a bond insurance agency in determining the probability that a fleet of Mid-West generation assets would generate insufficient cash to meet debt payments and reserve requirements.

Developed an Excel based model for a mid-west public utility to assist in developing annual targets for the amount of surplus generation capacity to be sold as merchant and in contracts of varying tenor. The model was integrated into the corporate financial model to assist in identifying the appropriate risk profile to support building the reserve fund and to delay future rate increases.

M&A and BANKRUPTCY ADVISOR

Advised creditors of the Puerto Rico Power Authority (PREPA) with regards to restructuring over eight billion dollars of debt. Multiple analyses were developed to support the restructuring negotiations including the development of a financial model to forecast the revenue requirement under different scenarios of fuel costs, types of generation resources, and cost savings initiatives.

Prepared an analysis of New Mexico Gas Company to support a prospective buyer. We assisted multiple clients with due diligence related to the acquisition of gas LDCs. Assisted the client with a review of the deal model including: assumptions about rate cases, assumptions regarding ROE, sales growth by rate class, and revenue by rate class. The engagement also included an assessment of the regulatory climate and potential conditions and costs associated with obtaining regulatory approval of the transaction.

Prepared a valuation of the Mountaineer Gas Company including the analysis of regulatory issues to support the debt financing associated with the purchase of the energy company.

Assisted an infrastructure fund in valuing power contracts and reviewed the regulatory model used in conjunction with establishing the price to bid for the acquisition of Northwestern Utility.

Prepared an analysis of Duquense Light to support an infrastructure fund's bid for the utility. The analysis included projections of growth opportunities through distribution & transmission investment, analysis of the POLR load obligation, and a review of key regulatory issues.

Developed a valuation model of Mirant including analysis of debt carrying capacity to assist a strategic player in the U.S. Power Industry determine whether to make an unsolicited offer to purchase Mirant.

Assisted an international oil company in development of modelling processes and assumptions to support a corporate effort to acquire a fleet of U.S. merchant generating assets.

Support a strategic player in valuing the Lake Road Generation Plant as part of their bid to acquire the asset in a competitive auction. Effort involved projection of future gross margins of the plant, analysis of the ISO-NE Forward Capacity Market, and analysis of transmission constraints.

Directed the valuation of the entire NRG portfolio on behalf of the bank creditors in the NRG bankruptcy hearings. The valuation work included advising on a range of types of generation assets in the U.S. as well as in Europe, South America, and the Asia-Pacific region. Mr Advised on the fairness of offers for assets being disposed of by NRG.

Assisted creditors in the valuation of assets in the NEG bankruptcy including the options for completing unfinished gas-fired generation assets. Served as the interim finance manager for the Lake Road Generation facility.

Member of team that advised Calpine as part of the company's restructuring and plan of reorganization. Assignment included analysis of the Canadian portfolio, advising on the sale of generation assets, modelling of long-term turbine maintenance costs, and the valuation of complex power contract.

Assisted the lenders on valuation and strategy related to AES' turn-back of the Granite Ridge Power Plant to the lender group.

Advised the bank and lender group on valuation and strategy related to the bankruptcy of the Kendall Power Plant.

ELECTRIC GENERATION FINANCE SUPPORT:

Market expert report for the Landfill Energy Systems, a national 66 MW portfolio of fourteen landfill gas power plants. The market expert report included a discussion of the key attributes of each of the power markets that the portfolio encompasses, long-term forecasts of wholesale electricity prices, and forecasts of gross margins.

Independent Market Expert Report to support the financing of the repowering and development of a fleet of combined cycle and simple cycle power plants in the ERCOT market. The independent market expert report was used to support the syndication of loans and obtaining debt ratings associated with investing over $1 billion in the Barney Davis, Nueces Bay, and Laredo Energy Center facilities.

Independent Market Expert Report to support the financing of Sequent Power's purchase of the Wolf Hollow 730 MW combined cycle power plant located in ERCOT. The report was used to support the

PA

syndication and rating of over $400M of primary and mezzanine debt. The report incorporated forecast of gross margins for both the contracted and non-contracted portions of the facility as well as providing a detailed description of the ERCOT market conditions and key assumptions to the financial analysis.

Independent Market Expert Report to support the financing of Invenergy's purchase of the partially completed Grays Harbor 620 MW combined cycle power plant located in the Pacific Northwest. The report was used to support the syndication and rating of over $100M of debt. The analysis included valuing both hedged and unhedged positions for the facility and conducting extensive due diligence regarding how NW power markets are likely to evolve and the role of independent power in a market dominated by vertically integrated public and investor-owned utilities.

Independent Market Report to support the refinancing of the Dynegy corporate revolver. The effort included analysis of multiple U.S. power markets, valuation of the fleet of generation assets and associated contracts, and review of regulatory conditions impacting the Company's ability to realize earnings in markets with competitive auctions to serve load.

Multiple forecasts of California power market prices including support of a bid for a cogeneration facility located in the San Francisco Bay area and sale of La Rosita.

Forecast of the New England power markets to support a bid for the First Light Generation Assets.

Forecast of the California and SPP power markets to support a bid for assets from the EIF portfolio.

Analysis of the ERCOT, PJM and MISO markets for multiple bids for merchant gas fired generation plants.

Development of multiple Confidential Information Memorandums to support the sale of power plants. CIMs included description of the wholesale power markets and summaries of the key attributes of the assets to be sold in auction.

Preparation of sale offering of the Audrain power plant in response to Ameren solicitation to acquire new resources. Effort included evaluation of likely competitors and the development of the bid strategy.

Advise on pricing for offering power contracts as well as the sale of gas-fired combined cycle power plant in the South-East. Pricing and sale price based upon projections of the value of the power plant as a merchant unit, assessment of potential competitors, and the analysis of transmission constraints.

Additional Expertise - Expert Testimony

Before the Arizona Corporation Commission, Direct and Settlement Testimony Of James A. Heidell, Docket No. E-01345A-16-0036 and Docket No. E-01345A-16-0123 In The Matter Of The Application of Arizona Public Service Company for a Hearing to Determine the Fair Value of the Utility Property of the Company for Ratemaking Purposes, To Fix a Just and Reasonable Rate of Return Thereon, To Approve Rate Schedules Designed to Develop Such Return.

Before the Public Utilities Commission of Nevada, Direct and Rebuttal Testimony Of James A. Heidell, Docket No. 16-06006, In The Matter of the Application of Sierra Pacific Power Company, d/b/a NV Energy, Filed pursuant to NRS 704.110(3), addressing its annual revenue requirement for general rates charged to all classes of Electric customers.

Before the Public Service Commission of Maryland, Rebuttal Testimony Of James A. Heidell, Case No. 9173, Phase II In The Matter Of The Current And Future Financial Condition Of Baltimore Gas And Electric Company.

Before the Indiana Utility Regulatory Commission, Rebuttal Testimony in Northern Indiana Public Service Company's request to raise rates in Cause No. 43526. Testimony on behalf of the utility related to ratchets and other mechanisms appropriate to recover costs allocated to large energy using customer classes.

Before Public Service Commission of the State of North Dakota, Direct and Rebuttal Testimony in Montana Dakota Utilities Co., and Otter Tail Corporation; Advance Determination of Prudence, Big Stone II Generating Station Case Nos. PU-06-481 and PU-06-482. On behalf of Montana-Dakota Utilities. 2007 & 2008. On behalf of Montana-Dakota Utilities.

Before the Public Service Commission of the State of Montana, Direct and Rebuttal Testimony in Montana-Dakota's General Rate Case – Marginal Cost of Service Study, Docket No. D2010.8.82. On behalf of Montana-Dakota Utilities.

Before the Public Service Commission of the State of Montana, Direct and Rebuttal Testimony in Montana-Dakota's General Rate Case – Marginal Cost of Service Study, Docket No. D2007.7.79. On behalf of Montana-Dakota Utilities.

Before the Minnesota Public Utilities Commission, Direct and Rebuttal testimony on behalf of Montana-Dakota Utilities regarding a Certificate of Need for the Big Stone II Power Plant, Docket No. CN-05-619. On behalf of Montana-Dakota Utilities.

Before the Ontario Electric Board, Expert Report regarding the 2006 Electric Rate Distribution Handbook and Rate Mitigation, on behalf of Hydro One Networks, Inc. January 2005.

Before the Washington Utilities and Transportation Commission, Direct Testimony in 2004 General Rate Case Regarding Electric Cost of Service & Rate Design and Gas Rate Design, April 2004. On behalf of Puget Sound Energy.

Before the Washington Utilities and Transportation Commission, Direct Testimony in 2001 General Rate Case Regarding Electric Cost of Service & Rate Design, November 2001. On behalf of Puget Sound Energy.

Before the Washington Utilities and Transportation Commission, Testimony Regarding the Need for a Special Competitive Rate for Intel. Docket No. UE-960299, 1996. On behalf of Puget Power.

Before the Washington Utilities and Transportation Commission, Rebuttal Testimony in the Merger of Puget Power and Washington Natural Gas Regarding Electric Rates, Docket Nos. UE-95-1270 & UE-960185, 1995. On behalf of Puget Power.

City of Rochester, Minnesota v. Southern Minnesota, State of Minnesota, County of Olmsted File No: 55-C3-05-002712. Testimony on behalf of the City of Rochester regarding the interpretation of a power contract. Testimony and deposition 2008.

Amana Society, Inc. and Amana Farms, Inc. v. GHD, Inc. and Excel Engineering, Inc. Testimony on behalf of GHD, INC regarding the economic performance of a manure digester and evaluation of claims of damages by Amana. Expert Report 2012, Jury Trial September 2012.

Affidavit of James A. Heidell & Mark Repsher, Appropriate Approach to Calculating the Weighted Cost of Capital, Docket No. ER14-2940-0000, U.S. Federal Energy Regulatory Commission, October 15, 2014.

Affidavit of James A. Heidell & Mark Repsher, on behalf of Peabody Energy Corporation to stay the final Clean Power Plan rule, September 9, 2015.

Declaration and report of James A. Heidell & Mark Repsher, Utility and Allied Petitioners' motion to stay the final Clean Power Plan rule, October 16, 2015.

Proxy Node LMP Distribution

LMP Range ($/MWh)	Number of Hours with Prices in Indicated LMP Range: Clean Energy #1 (Stanton)	Fox Tail (Tatanka)	Freeborn (Crystal Lake)	Lake Benton (Buffalo Ridge)	Blazing Star I&II (Blue Lake)	Cumulative Percentage of Hours with Prices in below Indicated LMP Range: Clean Energy #1 (Stanton)	Fox Tail (Tatanka)	Freeborn (Crystal Lake)	Lake Benton (Buffalo Ridge)	Blazing Star I&II (Blue Lake)
<-50	8	4	2	4		0.1%	0.0%	0.0%	0.0%	0.0%
-50--45	2		2			0.1%	0.0%	0.0%	0.0%	0.0%
-45--40	4	2	8	2	1	0.1%	0.0%	0.1%	0.0%	0.0%
-40--35	2	3	27	1	1	0.1%	0.1%	0.3%	0.1%	0.0%
-35--30	7	7	29	5	9	0.2%	0.1%	0.5%	0.1%	0.1%
-30--25	**17**	**14**	**21**	**13**	**9**	**0.3%**	**0.2%**	**0.7%**	**0.2%**	**0.2%**
-25--20	26	20	41	19	12	0.5%	0.4%	1.0%	0.3%	0.2%
-20--15	37	28	41	11	20	0.8%	0.6%	1.3%	0.4%	0.4%
-15--10	44	32	79	29	33	1.1%	0.8%	1.9%	0.6%	0.6%
-10--5	82	62	216	57	75	1.7%	1.3%	3.5%	1.1%	1.2%
-5-0	215	188	452	311	169	3.4%	2.7%	7.0%	3.4%	2.5%
0-5	558	522	518	589	393	7.6%	6.7%	10.9%	7.9%	5.5%
5-10	811	732	745	764	617	13.8%	12.3%	16.6%	13.7%	10.2%
10-15	1,661	1,490	1,418	1,532	1,159	26.5%	23.6%	27.4%	25.4%	19.0%
15-20	4,324	4,015	3,504	3,995	3,749	59.4%	54.2%	54.1%	55.9%	47.6%
20-25	3,091	3,469	3,148	3,211	3,825	82.9%	80.7%	78.1%	80.3%	76.7%
25-30	1,120	1,291	1,485	1,307	1,557	91.5%	90.5%	89.4%	90.3%	88.6%
30-35	463	536	571	533	651	95.0%	94.6%	93.7%	94.3%	93.5%
35-40	230	255	279	250	298	96.8%	96.5%	95.9%	96.2%	95.8%
40-45	115	136	152	158	160	97.6%	97.5%	97.0%	97.4%	97.0%
45-50	86	93	102	96	114	98.3%	98.3%	97.8%	98.2%	97.9%
>50	225	229	288	241	276	100.0%	100.0%	100.0%	100.0%	100.0%
Total # of Hours	13,128	13,128	13,128	13,128	13,128					

Comparison of Proxy Nodes with Load Node

Average Real Time Nodal Prices and Components: 1-1-2016 to 6-20-2017								
		Price Components ($/MWh)			Percent LMP Basis (%)	Basis Components ($/MWh)		
Wind Project	Proxy Node	LMP	Congestion	Loss		LMP	Congestion	Loss
NSP Load	NSP.NSP	21.79	(3.42)	(1.35)	0.0%	0.00	0.00	0.00
Fox Tail	MDU.TATANKA1	19.83	(4.11)	(2.62)	-9.0%	(1.95)	(0.69)	(1.27)
Crowned Ridge	OTP.BIGSTON1	19.43	(4.07)	(3.06)	-10.8%	(2.35)	(0.64)	(1.71)
Lake Benton	NSP.BUFFR_TR2	19.60	(4.14)	(2.83)	-10.1%	(2.19)	(0.72)	(1.47)
Clean Energy #1	GRE.STANTO1	19.01	(4.43)	(3.08)	-12.8%	(2.78)	(1.01)	(1.72)
Blazing Star I&II	NSP.BLUE_LK7	21.11	(3.75)	(1.70)	-3.1%	(0.68)	(0.33)	(0.35)
Freeborn	ALTW.CRYLAKE 2	19.13	(4.48)	(2.95)	-12.2%	(2.65)	(1.05)	(1.60)
Wind Portfolio Average		19.69	(4.16)	(2.71)	-9.6%	(2.10)	(0.74)	(1.35)

Marginal Losses

Average Real Time Nodal Price Basis Between Wind Projects and NSP Load Node: 1-1-2016 to 6-20-2017							
Wind Project	Proxy Node	LMP Basis	Congestion Basis	Loss Basis	LMP Basis	Congestion Basis	Loss Basis
Fox Tail	MDU.TATANKA1	(1.95)	(0.69)	(1.27)	100%	35%	65%
Crowned Ridge	OTP.BIGSTON1	(2.35)	(0.64)	(1.71)	100%	27%	73%
Lake Benton	NSP.BUFFR_TR2	(2.19)	(0.72)	(1.47)	100%	33%	67%
Clean Energy #1l	GRE.STANTO1	(2.78)	(1.01)	(1.72)	100%	36%	62%
Blazing Star I&II	NSP.BLUE_LK7	(0.68)	(0.33)	(0.35)	100%	49%	51%
Freeborn	ALTW.CRYLAKE2	(2.65)	(1.05)	(1.60)	100%	40%	60%
Wind Portfolio Average		(2.10)	(0.74)	(1.35)	100%	35%	64%

JAH - 3

STATE OF NORTH DAKOTA
PUBLIC SERVICE COMMISSION

Northern State Power Company
Advance Prudence – 1,550 MW Wind Portfolio
Application

Case No.: PU-17-120

VERIFICATION

STATE OF WASHINGTON)
) **ss.**
COUNTY OF _SAN JUAN______)

James A. Heidell, being first duly sworn on oath, deposes and states that he has read the testimony and exhibits submitted in the above captioned matter under his name, that they were prepared by him or under his direction, that he knows the contents thereof, and that the same are true and correct to the best of his knowledge and belief.

James A. Heidell

James A. Heidell

Subscribed and sworn to before me this 27 day of July, 2017.

DENNIE A CARTER
NOTARY PUBLIC
STATE OF WASHINGTON
COMMISSION EXPIRES SEPTEMBER 16, 2020

Dennie A. Carter

Notary Public
My Commission Expires: 7/26/2020