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TESTIMONY

JAMES A HEIDELL

STATE OF NORTH DAKOTA

BEFORE THE

NORTH DAKOTA PUBLIC SERVICE COMMISSION

NORTHERN STATES POWER COMPANY CASE NO. PU-20-433

ADVANCE DETERMINATION OF PRUDENCE – HEARTLAND DIVIDE II WIND PROJECT

49 PU-20-433 Filed 06/10/2021 Pages: 41
Exhibit 6 - Pre-filed Direct Testimony of James A. Heidell (Public)
Northern States Power Company

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I. Introduction

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

A. My name is James A. Heidell and I work as a Director for PA Consulting Group, Inc. (PA). My business address is 1700 Lincoln Street, Suite 3550, 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 or NDPSC).

Q. Please summarize your qualifications and experience.

A. I have worked in the energy industry for the past 40 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 an MBA in finance from the University of Washington. I am a CFA Charterholder. 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 (ADP), Big Stone II Generating Station Case Nos. PU-06-481 and PU-06-482. I have submitted pre-filed direct testimony on behalf of Advocacy Staff in the following dockets:

- Montana-Dakota Utilities' 2020 Natural Gas Rate Increase Application (Case Number PU-20-379);
- Montana-Dakota Utilities' request for an ADP and Certificate of Public Convenience and Necessity for an 88 MW Simple Cycle Combustion Turbine (Case Number PU-19-307);

- Northern States Power Company's request for an ADP for the Dakota Range III Wind Facility (Case Number PU-18-430);
- Northern States Power Company's request for an ADP for the Dakota Range Wind Project (Case Number PU-17-372);
- Northern States Power Company's request for an ADP for 1,550 MW of Wind (Case Number PU-17-120);
- Otter Tail Power Company's Request for an ADP for the Astoria CT and Merricourt Wind Project (Case Nos. PU-17-140, PU-17-141, and PU-17-143);
- Advance Prudence – Biomass Application for deferred accounting Northern States Power Company (Case Nos. PU-17-270, PU-17-271, and PU-17-322); and
- Northern States Power Company Resource Treatment Framework (Case Nos. PU-12-813 et al.).

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's (NSP or Company) request for an ADP for the proposed Power Purchase Agreement (PPA) between the Company and the Heartland Divide II Wind Project (Project). The 200 MW Project will be in Audubon County, Iowa. The Company is requesting an ADP for the 150 MW PPA, which would be treated as a system resource; the remaining 50 MW will be dedicated to serve the Minnesota Renewable*Connect Program.

The impetus for the 150 MW of wind is the Company's obligations under a Minnesota jurisdictional Retail Electric Service Agreement (RESA) with Honeycrisp LLC, an affiliate of Google LLC (Honeycrisp), for a planned data center in Becker, Minnesota (Honeycrisp RESA).

The Honeycrisp RESA requires the Company to procure incremental renewable generation to match the data center site's expected annual energy use. The Commission reviewed and approved, with conditions, a similar request related to the ADP for the Dakota Range III PPA (Case No. PU-18-430). The Dakota Range III project is targeted to serve 150 MW of the 300 MW needed for the first phase of the data center. The Heartland Divide Project is intended to fulfill the remaining 150 MW. The PPA energy prices are expected to lower the Company's overall generation costs.

The Company is proposing to allocate the Project's remaining 50 MW to the Renewable*Connect program. The costs of this 50 MW will be the sole responsibility of Minnesota customers.

II. Organization of the Testimony

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

A. Yes. I start with presenting my recommendations and findings and then I discuss in detail the analysis I conducted to support my recommendations and findings. I then address additional factors considered. Finally, I address proposed conditions if the ADP is approved. My testimony is separated into fifteen sections:

- A summary of my recommendations (Section III);
- A summary of my findings (Section IV);
- The impetus for the PPA (Section V);
- An overview of the PPA (Section VI);
- An overview of the Honeycrisp RESA (Section VII);
- An evaluation of the ADP (Section VIII);
- An assessment of the need for the Project (Section IX);
- Review of NSP's modeling (Section X);
- An evaluation of the Company's economic analysis of the Project (Section XI);
- My independent economic analysis of the Project (Section XII);
- Accounting for fuel and purchase cost power (Section XIII); and
- Consideration of additional issues (Section XIV).

Q. Are you sponsoring any exhibits to your testimony?

A. Yes, I am sponsoring two exhibits:

- Exhibit JAH-1: James Heidell CV
- Exhibit JAH-2: PA Projected Energy Cost Savings Compared to Market

III. Summary of Recommendations

Q. Do you recommend the Commission approve the Company's Application for an ADP to add the proposed Project to the Company's integrated system?

A. I believe the Commission should consider several factors as it determines whether to approve the Application. I concluded that NSP was reasonable to assume the PPA will provide energy cost savings for ND ratepayers, albeit minimal. Regardless, I have the following four concerns:

- The Company does not need the resource to meet energy and capacity requirements associated with its retail load obligations. Rather, the Company is taking a long position in the Midcontinent Independent System Operator (MISO) market and expecting the PPA cost to be lower than the revenues associated with selling the Project's energy in MISO Zone 3.
- The Company's proposal to procure a resource out of MISO Zone 1 creates greater basis risk between the value of the energy produced and the cost of the energy purchased to serve retail load.
- The Company appears to have selected this PPA based upon requirements to procure a new resource associated with the Honeycrisp RESA. The Company selected the resource because it has known interconnection costs; however, it is unclear whether the PPA represents the least cost option.
- The Company is proposing to bifurcate the PPA between a system resource and a resource dedicated to Minnesota. The bifurcation of resources was a complex and unresolved issue raised in the Company's Resource Treatment Framework (Case

Nos. PU-12-813 et al.) and the Company's proposal was not accepted by the Commission.

Because of these concerns, if the Commission approves the PPA, I recommend several conditions.

Q. If the Commission approves the PPA what conditions or qualifications do you recommend?

A. As conditions to its approval of the PPA, I recommend the Commission:

- Limit total PPA costs to how NSP identified them in its Application; ND customers should not be responsible for absorbing any contract modifications without further Commission review;
- Require NSP provide ND customers with their share of the Project's Renewable Energy Credits (REC) in NSP's Fuel Cost Rider (FCR) calculations;
- Insulate ND customers from any potential costs associated with NSP needing to purchase RECs to satisfy its commitments under the Honeycrisp RESA. Because the Honeycrisp RESA is a special retail rate developed under Minnesota jurisdiction, NSP should never be permitted to allocate costs associated with these REC purchases to ND customers; and
- Require NSP to treat the full 200 MW of the PPA as a system resource.

IV. Summary of Findings

Q. Would you please provide a summary of the findings you believe the Commission should consider as it determines whether to approve NSP's Application for an 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 find the following to be favorable to approving the Application:

- NSP reasonably expects that the Project will lower power costs to ND customers by decreasing net power costs to NSP as a result of selling the Project's output into MISO's Zone 3 energy markets at a price greater than the PPA cost;
- The incremental energy from the Project is not enough to materially impact NSP's resource energy mix or MISO's overall reliability;
- The resource addition aligns with NSP's stated intention to use Dakota Range III and the Project to fulfill incremental renewable generation requirements under the Honeycrisp RESA; and
- The Project appears to align with the long-term objectives of the Company.

While there are favorable facts, however, I also have the following concerns:

- The Project is not needed to serve NSP's retail load in the near term absent NSP's obligation under the Honeycrisp RESA to procure new renewable energy sources;
- The Project is not needed for capacity;
- While the expected data center load will create additional capacity requirements beyond the Project's accredited capacity, NSP failed to incorporate those costs into the Project's projected system savings; and
- Enabling NSP to allocate 50 MW to exclusively serve the Renewable*Connect Program reduces the benefit of the Project to ND customers and could create a precedent allowing a company to bifurcate a resource acquisition between a system resource and a non-system resource.

V. The Impetus for the PPA

Q. Would you please provide an overview of the Company's Application for the ADP?

A. The Company has requested an ADP for a PPA with Heartland Divide II, LLC, the owner of the Project. Heartland Divide II, LLC is a subsidiary of NextEra Energy Resources. The Project is scheduled to be online by the end of 2021 and the Company signed a 25-year PPA for the entire Project output. Notably, 150 MW of the 200 MW Project will be designated as a system resource (the subject of the ADP), while the other 50 MW will be dedicated to Minnesota to serve the Renewable*Connect program. The impetus for the PPA is the requirement under the Honeycrisp RESA to secure incremental new renewable resources to serve the planned data center's load. The Company has requested that the renewable energy attributes associated with the 150 MW be entirely retained by the Company to meet these obligations under the Honeycrisp RESA.

Q. Would you please summarize the retail service contract with Honeycrisp?

A. In January 2019, NSP entered into the Honeycrisp RESA to serve the load of a new data center at the Company's Sherco generating plant site in Sherburne County, Minnesota. The contract with Honeycrisp not only included pricing terms, but also a commitment by NSP to secure incremental new renewable resources to serve the load of the data center. NSP intends to serve the load of the first phase of the data center with 300 MW of new wind resources. In Docket PU-18-430 the Commission approved an ADP for the first 150 MW of wind from the Dakota Range III wind project, with conditions. NSP plans to use 150 MW from the Project to meet the remaining 150 MW of the data center's initial estimated need.

Q. Is the NDPSC being requested to approve the Honeycrisp RESA?

A. No. The Honeycrisp RESA is a Minnesota retail load contract approved by the Minnesota Public Utilities Commission (MPUC) in Dockets E-002/M-19-39 and E-002/M-19-60. My understanding is that the rates charged to retail customers in Minnesota are beyond the jurisdiction of the NDPSC.

Q. Will the Project be used to exclusively serve the Honeycrisp data center load?

A. No, NSP is proposing to treat 150 MW of Heartland Divide II as a system resource. The energy and capacity requirements imposed by the data center will be served from system resources (including any wholesale market purchases). Variations in data center load may impact whether NSP must retire RECs on behalf of the Project; however, it does not change NSP's commitments under the PPA.

Q. Is the analysis of the data center retail load relevant to North Dakota if it is beyond the jurisdiction of the NDPSC?

A. Yes, the selection of the Project was driven by the need to meet the Honeycrisp RESA and not by a resource need identified in the Company's IRP. NSP has an obligation under the Honeycrisp RESA to procure new renewable generation even if the Commission determines that the PPA has minimal or no benefits to North Dakota customers. While NSP reasonably expects the Project will provide rate savings to North Dakota customers, the extent to which adding a new major load in Minnesota may benefit North Dakota customers in part depends on how the capacity allocation changes based upon the actual data center load. For example, the Company's need for additional capacity resulting from the data center load will create an additional cost.

Q. Have you provided an analysis for the Commission considering the data center load to be simply additional organic load growth for the Company?

A. Yes. I believe it is appropriate for the Commission to consider the impacts of the data center load for reasons discussed earlier in my testimony. However, should the Commission wish to consider the data center load to be natural load growth that the Company has an obligation to serve, the analysis in Section XII of my testimony addresses this view and evaluates the economics of the proposed PPA independently of the load addition.

Q. What is the Renewable*Connect program?

A. The Renewable*Connect is a voluntary program for residential customers of NSP in Minnesota to subscribe to up to 100% clean energy. NSP retires the RECs associated with the resources used in this program for the benefit of the customers signing up for clean energy.

VI. Summary of Heartland Divide II PPA

Q. Have you reviewed the PPA?

A. Yes, I have reviewed the Wind Energy Purchase Agreement.[1]

Q. Would you please provide an overview of the PPA?

A. The company has signed a 25-year PPA with an expected commercial operation date at the end of December 2021. The confidential pricing is provided in the Company's pre-filed direct testimony and incorporated into my analysis of the expected benefits of the PPA. Heartland Divide II, LLC is responsible for obtaining all necessary permits and for constructing the Project, as well as all MISO interconnection costs. NSP is responsible for transmission costs beyond the Point of Delivery located in MISO Zone 3.

Q. What is the significance of the Point of Delivery located in MISO Zone 3 and not in Zone 1?

A. There will be pricing differences between the price at which NSP buys energy to meet its retail load obligations (which is the Minnesota Hub in Zone 1) and the price that it will be paid for the Project's energy sold to MISO in Zone 3. Later in my testimony I summarize my expectations regarding the price differential between MISO Zones 1 and 3.

Q. Are there other factors to consider in determining the pricing that a wind unit will get besides the MISO zone it is located in?

A. Yes, there is often a basis differential between the average zonal price and the node where a generator injects power into the grid. In my comparison of Zone 1 and 3 prices, however, I did not assume a basis differential.

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[1] NSP's confidential response to NDPSC Advocacy Staff Data Request 2-6. Wind Energy Purchase Agreement Between Northern States Power Company and Heartland Divide Wind II, LLC.

Q. Are there options for procuring new wind resources in Zone 1?

A. Yes, there are over 25 projects in the interconnection queue totaling 5.5 GW.[2] However, the cost of interconnection of these projects to the transmission system is not known.

Q. Why did NSP select a wind resource in Zone 3?

A. NSP was concerned about attempting to develop projects and not being able to obtain a timely estimate of definitive interconnection costs. **[Trade Secret Begins]** [redacted][3] **[Trade Secrete Ends]**

Q. Is NSP responsible for paying Heartland Divide II, LLC for curtailments?

A. No. Under the terms of the PPA, NSP will not pay for curtailments;[4] however, curtailments will reduce the energy sold to NSP.

Q. How is the interconnection treated in the PPA?

A. Heartland Divide II, LLC is responsible for contracting with MISO for the interconnection as well as paying for all interconnection costs and providing for firm transmission to the Point of Delivery in MISO Zone 3.

Q. Has NSP demonstrated that Heartland Divide II is the lowest cost option to add an additional 150MW of wind capacity to the NSP system?

A. No, NSP selected the Project based upon its ability to meet NSP's contractual commitment under the Honeycrisp RESA and to secure additional new wind resources

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[2] Source: https://www.misoenergy.org/planning/generator-interconnection/GI_Queue/gi-interactive-queue/

[3] NSP Confidential Response to Advocacy Staff 2-3.

[4] Response to Advocacy Staff 2-6, Wind Energy Purchase Agreement Between Northern States Power Company and Heartland Divide Wind II, LLC Section 7.2 (B)

prior to the expected commercial operation date of the data center.[5] I have noted elsewhere in my testimony that the Minnesota Department of Commerce has concerns about the Company's selection process.

Q. Is NSP's PPA with Heartland Divide II subject to the approval of the NDPSC?

A. Commission approval of the PPA is not a requirement, however, NSP has the option to terminate the PPA under certain conditions and NSP has the right to terminate the agreement if the NDPSC does not approve the requested ADP and affirm that all the costs are recoverable from retail customers.[6] There are multiple dates and conditions under the NDPSC approval clause where the Company can terminate the PPA.

VII. Summary of the Honeycrisp RESA

Q. Would you please provide an overview of the Honeycrisp RESA?

A. NSP negotiated, and the MPUC approved, a long-term RESA to develop and serve a new data center to be built on 315 acres of land at the Company's generating plant site in Sherburne County, Minnesota.[7] The initial term of the contract is ten years and requires NSP to add incremental renewable energy sufficient to meet the annual energy consumption of the data center. NSP will retire the RECs associated with the incremental renewable resources for the benefit of the Honeycrisp RESA in the amounts that match the data center load. The contract provides some flexibility for banking RECs so that the annual generation of the new resources does not have to exactly match the annual loads of the data center.

Q. How does NSP plan to meet the requirement for incremental renewable resources under the RESA?

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[5] NSP response to NDPSC Data Request No. 2-3 and the first paragraph of P 2 of NSP's application in this proceeding.

[6] NDPSC Data Request No. 3-3 and NDPSC Data Request No. 2-6 Power Sales Agreement Section 6-1

[7] Minnesota Docket E-002/M-19-39 & E-002/M-19-60, July 15, 2019.

A. NSP estimated that it needs 300 MW of wind generation. 150 MW from Dakota Range III has already been acquired and 150 MW of Heartland Divide II is intended to supply the balance.[8]

Q. Is Heartland Divide II needed to supply sufficient RECS to meet the data center energy requirements?

A. Based upon the data provided by the Company it appears that [**Confidential Data Begins**] [redacted] [**Confidential Data Ends**][9]

Q. Does the Honeycrisp RESA have specific commitments related to contracted demand or minimum energy requirements?

No. There are confidential load forecasts as well as an expected load factor associated with the load; however, there are no specific load commitments. Given the uncertain load growth pattern, the contract provides flexibility regarding the timing for meeting the annual energy requirements with incremental renewable resources.

Q. Will NSP have to build new transmission facilities to serve the data center?

A. Yes. The data center will be served at transmission-level voltage and NSP will be responsible for the costs associated with constructing a substation and transmission that will connect with the data center. The estimated cost of these facilities was disclosed in the Dakota Range proceeding, Case No. PU-18-430. It remains the Company's position

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[8] NSP Application for an ADP for the 200 MW Heartland Divide Wind II PPA at 7.

[9] Data center load provided in response to NDPSC 2-2. Annual production for Dakota Range III and Heartland Divide determined from response to NDPSC-1-2 Alt A from the tab "Resource Annual".

that North Dakota will share in recovery of these costs since North Dakota customers are receiving benefits from the data center.[10]

Q. Are the costs of the new transmission incorporated in the expected savings to North Dakota customers as result of the PPA?

A. No, those costs are not included.

VIII. Evaluation of the ADP Application and Project

Q. Would you please provide an overview of your analysis of the ADP application?

A. My assessment of the Project addresses two fundamental questions:

- First, is the Project needed to serve NSP's load?
- Second, will the Project lower energy and capacity costs for NSP's North Dakota customers?

Q. Does the Company need the Project to meet the energy requirements associated with NSP's retail load?

A. No. The IRP identifies the need for small amounts of energy efficiency, demand response, and distributed solar through 2025. The IRP shows 500 MW of solar being added annually in 2025 and 2026, with the first wind resources added in 2032.[11] In the North Dakota Scenario, however, NSP shows no wind units added in this decade and no utility scale solar added until 2029.[12]

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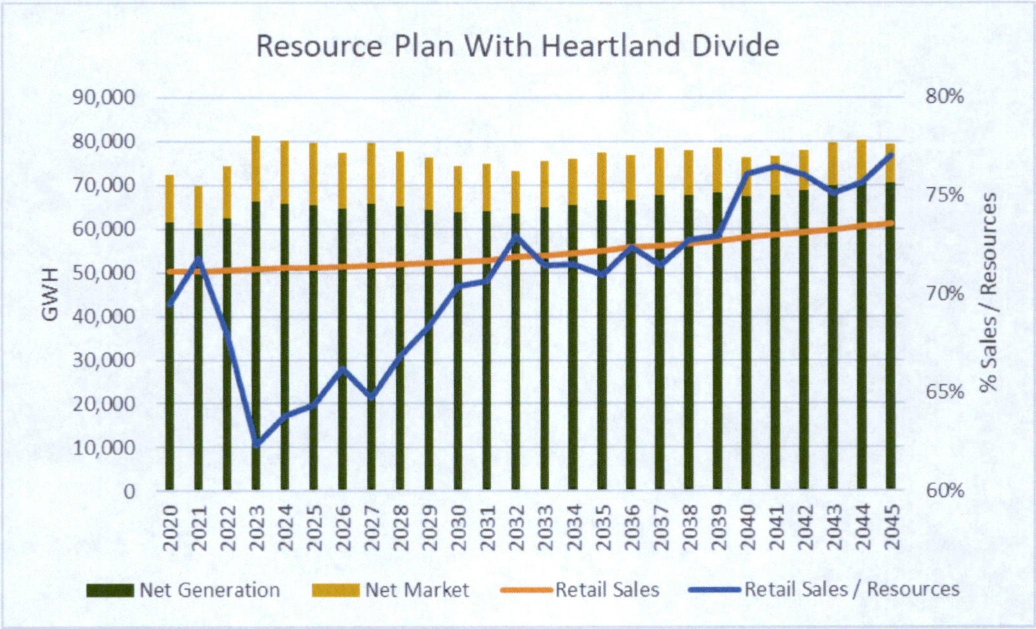
[10] NSP Response to Advocacy Staff Data Request 3-5.
[11] IRP Figure 3-2 Supplemental Preferred Plan Resource Additions.
[12] IRP Table 3-1.

Q. Does the Company's modeling of Heartland Divide II in EnCompass confirm the Project is not needed to meet retail load?

A. Yes, I prepared a graph of the Company's forecast of total net generation plus net market purchases and sales versus the forecast retail sales. In 2023 the ratio of retail sales to resources is 62%. In other words, the Company is generating significantly more energy than needed to meet its retail load. My analysis is shown graphically below.



Q. Does the Company generate more energy from its owned resources and PPAs than needed to serve its retail load obligations?

A. Yes, based upon the Company's simulations in EnCompass, for many modeled years the Company generates more than 25% more energy than needed to meet retail load. By dispatching excess generation into MISO, the Company would potentially generate margins it could use to offset its power costs associated with serving retail load. NSP would essentially function as a merchant generation company; building/controlling generation with the expectation that selling energy into MISO will be profitable.

Q. If the Company has not established a resource need, how would it serve the new load from the data center absent the Heartland Divide II PPA?

A. The Company purchases all of its energy to meet its retail load from MISO in Zone 1. The Company offsets the costs of purchasing this energy by selling energy back to MISO. Historically, the Company-owned and -controlled generation has been in MISO Zone 1; however, the Project will be in MISO Zone 3. In the absence of the Project, the Company would simply increase its purchases of energy from MISO and the Company's generation would not change significantly.

Q. Does the Company need the Project to meet its capacity requirements/serve NSP's load?

A. No, based upon the Company's IRP the Company will not need new capacity until 2026.[13] The 2026 data includes the data center load.[14]

Q. If the Commission approves the ADP application, what savings and costs do you expect for NSP's ND customers related to energy and capacity?

A. If the Commission considers the ADP only in the context of being a resource addition, it is expected to lower average system energy costs. Because the Project is being added to meet the requirements of the Honeycrisp RESA, I also considered the potential impacts of the data center load. I determined, given the relatively small size of the data center load, the Project should not significantly impact MISO Zone 1 energy costs and should result in a lower average system energy cost. NSP further anticipates a reduction in the allocation of capacity costs to North Dakota because additional load will be in Minnesota, not North Dakota. Because the peak demand of the data center may exceed the accredited capacity of newly added resources there may be additional capacity costs that will in-part be allocated to North Dakota.

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[13] IRP Table I-3.
[14] IRP Table I-3.

Q. Based on the expectation of energy savings, should the Commission grant an ADP for the Project?

A. While the Project is expected to slightly lower both the Company's system average production cost and power costs for the ND customers, I would recommend the Commission also consider the following:

- The Company has not demonstrated that the resource acquisition is least cost;
- The Company is procuring a resource outside of MISO Zone 1;
- The Project is not needed to serve retail load;
- The resource is not needed for energy or capacity; and
- The proposal seeks to bifurcate the resource by only treating part of the PPA as a system resource.

Q. Has the Company demonstrated Heartland Divide II is the least cost wind resource?

A. No, while the Project appears to be a low-cost wind resource, NSP's selection process was in part driven by the timing of adding a resource to meet its requirements under the Honeycrisp RESA. It is unclear whether, with more time, the Company could have identified a lower-cost wind resource, or a Zone 1 resource of comparable-cost.

Q. Why is the location of the resource (MISO Zone 1 or Zone 3) significant?

A. NSP is creating additional basis risk by assuming it will be profitable to sell energy from the Project into MISO Zone 3. Ultimately, profitably will depend on whether the price NSP could obtain from selling wind generation into MISO Zone 3 exceeds the costs NSP would incur from purchasing power from MISO Zone 1. While both zones are within MISO, by procuring resources outside of Zone 1, NSP appears to be betting on the MISO market rather than hedging the power costs for retail load. For example, NSP could argue it would be advantageous to purchase power from Louisiana in MISO 9; however, it would not be a logical place for NSP to procure resources to serve is retail load.

Q. What do you recommend that the Commission consider when determining whether NSP should be permitted to bifurcate its PPA?

A. Historically, the Commission has not approved ADPs when a company fails to demonstrate the resource is least cost and instead requires those resources have separate treatment in the FCR. To my knowledge the Commission has not bifurcated a resource into (1) a system resource and (2) a resource dedicated to Minnesota. While NSP previously proposed separately acquiring resources for North Dakota in its proposed Resource Treatment Framework, the Commission did not accept the proposal. I believe the policy of creating separate resources for different states, let alone separating a resource into a system and non-system resource, may be beyond the scope of the ADP.

IX. Review of NSP's EnCompass Modeling

Q. How did the Company evaluate the proposed Project's impacts on its system costs?

A. The Company conducted simulations to evaluate the projected impact on its system costs. The analysis was conducted in EnCompass, an hourly chronological production cost model. In projecting the economic dispatch of each NSP resource, EnCompass simulates the operation of the MISO System and estimates the total system costs impact of the Project and includes a calculation of the system-level net present value of savings.

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

A. Yes. Specifically, I reviewed:

- The planning scenarios developed by the Company;
- The natural gas price assumptions used in the model;
- The Project's modeled characteristics;
- Other NSP system inputs (including energy/demand forecast, wind integration costs, net generation, energy purchases and sales, wind capacity factor, generation profile and curtailment); and
- The reasonableness of the MISO wholesale electric market price assumptions.

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

A. Yes. The Company developed a base case scenario using the IRP along with the assumed operation of the 99 MW Minnesota Mower Wind Project and the wind repowering projects currently under consideration by the Commission in Case No. PU-20-425. The Company then developed an alternative case adding the 200 MW Heartland Divide II project. In addition, the Company developed two alternative scenarios with low gas/low market prices and high gas/high market prices to estimate the savings by adding Heartland Divide II.

Q. Does the Base Case or other scenarios account for the additional estimated data center load?

A. Yes, both the cases with and without the Project use the same sales forecast and include the data center load.[15, 16]

Q. How will the Project earn revenues in the MISO market?

A. The Project will earn revenues based upon bidding into the MISO market and receiving the market clearing price for its generation. The market clearing price will reflect congestion and losses allocated to each generator's interconnection node.

Q. Are the market prices forecast critical to the evaluation of benefits of the Project?

A. Yes, as previously noted the Project's projected savings are a function of both the PPA cost and the forecast of market prices. NSP customers are likely to benefit from any PPA added to the model so long as the PPA price is lower than the assumed MISO market

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[15] NSP Response to NDPSC 1-2 Alt A_EO_Heartland Divide Base Case_2010-10-15 TRADE SECRET IN Entiriety.xlsx tab (Company Annual).

[16] NSP Response to Advocacy Staff Data Request 3-1.

prices. In its EnCompass modeling, NSP constrained market sales to 25% of its load to restrict the model from potentially adding limitless low-cost wind resources.

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

A. Yes. When the marginal unit setting overall market price is a natural gas-fired generation unit, there will be a strong relationship between gas and power prices. The MISO Market Monitor has reported a strong correlation between natural gas prices and wholesale market prices.[17] Notably, in 2019, coal units set the market clearing price 47% of the time whereas natural gas units set the clearing price 51% of the time.[18] I therefore suspect natural gas will continue to set the market price in most hours.

Q. Are the Company's forecast of natural gas prices reasonable?

A. Yes, I compared the Company's delivered natural gas price forecast for the Ventura pricing hub in Minnesota with PA's forecast for the hub. While not egregious, the Company's forecast is generally slightly lower than PA's forecast in the near term, which would tend to slightly decrease the associated market prices and projected benefits of the Project.

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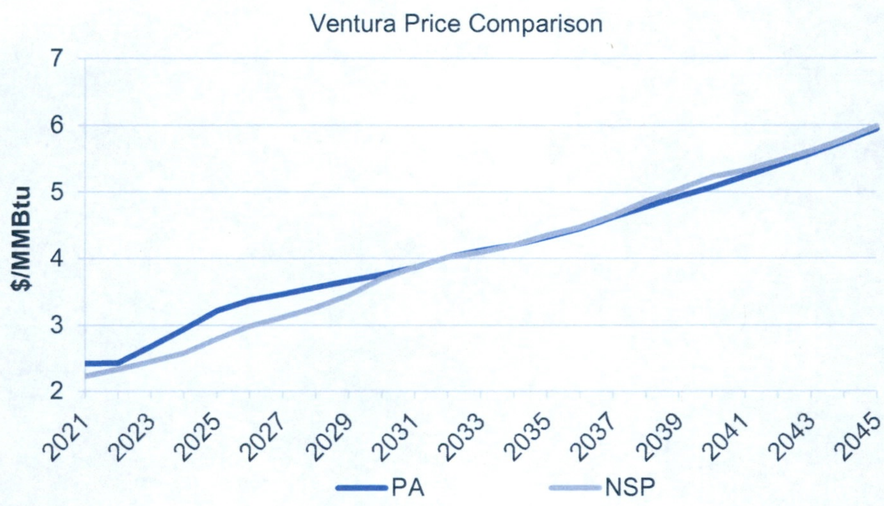
[17] 2019 State of the Market Report, Midwest ISO p 4.
[18] 2019 State of the Market Analytic Report, Midwest ISO, Table A1. https://cdn.misoenergy.org/2019%20State%20of%20the%20Market%20Analytical%20Appendix455180.pdf

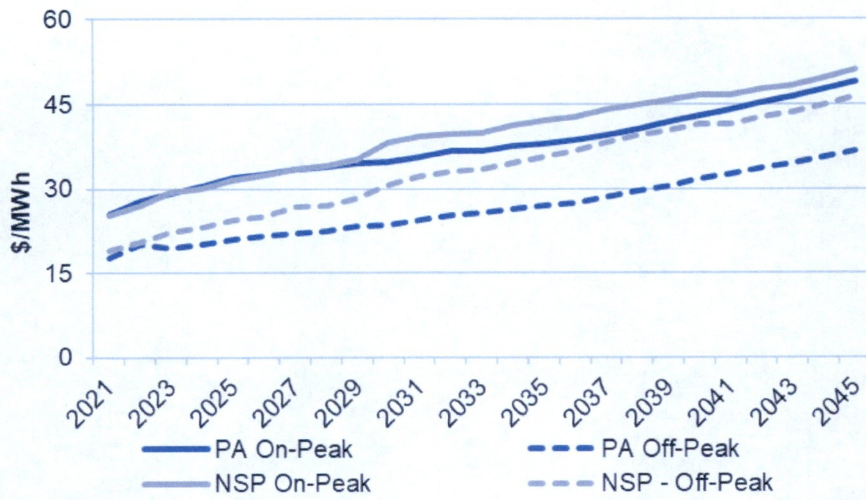
Figure 1. PA Natural Gas Price Forecast vs. NSP Forecast ($/MMBtu)



Q. How does the Company's assumptions of MISO power prices compare to PA's forecast?

A. In MISO Zone 3, the Company's MISO off-peak power prices forecast are higher than the PA forecast whereas on-peak prices are similar through 2029, after which the PA prices are lower. This is shown graphically in Figure 2 below. I find the Company's assumptions to be in the range of reasonableness but note the PA forecast results in lower savings associated with the PPA.

Figure 2. MISO Zone 3 Forecast Prices ($/MWh)



Q. How does the proposed Project impact the Company's capacity mix from a resource diversity perspective?

A. The Project will not significantly change the Company's capacity mix. The Project is expected to add approximately 34 MW of accredited capacity.[19] If one considers the added load from the data center, the net impact is to increase the Company's firm capacity requirements should not be significant in the near term. In 2025 the Company's total firm capacity is 6,151 MW.

Q. Does the proposed Project impact the Company's energy mix from a resource diversity perspective?

A. No. I reviewed the results from the EnCompass modeling and have summarized the resource mix in the two tables below. In most years the mix of wind increases by only 1%.[20] Beyond 2035, the mix of wind changes as a result of different timing of wind

[19] NSP Response to NDPSC-02-006.

[20] NSP Response to NDPSC 1-2 based upon the model tab "Energy Mix All"

additions between the Base Case and the case adding the Project; however, both plans ultimately result in the same amount of wind generation

Table 1: GWH Resource Mix* without Heartland Divide II

Resource Type	2022	2025	2030	2034	2040
Coal	10%	3%	0%	0%	0%
Nuclear	22%	22%	22%	14%	5%
Gas / Oil	20%	26%	24%	20%	13%
Hydro	4%	2%	1%	1%	1%
Wind / Solar	29%	30%	35%	45%	61%
Energy Efficiency	13%	16%	18%	20%	18%
Other	1%	1%	0%	0%	1%

* Table excludes system purchases

Table 2: GWH Resource Mix* with Heartland Divide II

Resource Type	2022	2025	2030	2034	2040
Coal	10%	3%	0%	0%	0%
Nuclear	22%	22%	22%	14%	5%
Gas / Oil	20%	26%	23%	20%	15%
Hydro	4%	2%	1%	1%	1%
Wind / Solar	30%	31%	36%	45%	59%
Energy Efficiency	13%	15%	18%	20%	18%
Other	1%	1%	0%	0%	1%

* Table excludes system purchases

X. Economic Analysis based on NSP Modeling

Q. Did you review NSP's estimate that the PPA will have a $97.4M reduction in revenue requirements on a net present value basis?

A. Yes, I reviewed the estimate derived from the Company's EnCompass modeling (previously summarized above). It should be noted that the Company's savings estimate is for the 200 MW of the Project and under the Company's proposal North Dakota's allocation of the energy savings is based upon 150 MW of the Project.

Q. Have you estimated the benefits to NSP's North Dakota customers?

A. To estimate the benefits to North Dakota I made the following two adjustments: (1) I reduced MW to reflect only the portion of the PPA being reflected as a system resource and (2) I considered the portion of savings that will directly impact North Dakota. First, I noticed the Company's estimate is based upon modeling the entire 200 MW PPA. Because NSP is only proposing to treat 150 MW as a system resource, only 75% of the estimated savings would be reflected in the system power costs and the FCR. Second, North Dakota represents approximately 5.55% of the retail energy system sales.[21] At a high level, the Company's estimate of the present value of power cost savings to North Dakota customers is on the order of $4.02M. On an annual savings per kWH basis, this translates into approximately $0.0001 / kWH.

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

A. Yes. To account for the intermittency of the Project's generation output and the costs the Company incurs to maintain a balanced system, the EnCompass analysis included an additional adder to the Project's PPA price. Adding such a wind integration charge when evaluating the economics of wind energy is an industry accepted general practice, and I believe the Company applied it appropriately in the EnCompass analysis.

Q. What did you conclude regarding the Company's economic analysis of the Project?

A. I concluded that NSP conducted a reasonable analysis in EnCompass. I reviewed the Company's analysis and found the input assumptions and output results to be reasonable. However, I note that there is a range of reasonable results given the uncertainties surrounding fuel prices, generation additions, generation retirements, and load.

XI. Independent Economic Analysis of the Project

[21] NSP FCR filing for January 2021 Attachment H, Docker PU-21-012

Q. Would you please summarize your independent economic analysis of the Project?

A. Yes. While the Company's EnCompass analysis sought to evaluate the Project as a resource integrated into the NSP system, I took an alternate approach to evaluate the project as a MISO energy market participant. Simply stated, my approach assumes that additional generation in Zone 3 would not significantly change generation dispatch in Zone 1 so MISO would dispatch the same NSP resources regardless of whether NSP has a PPA with Heartland Divide II. In addition, in reviewing changes in the dispatch of the Company's generation with and without the Project, I did not find the modeling results convincing.

Q. Would you please describe the foundation of your economic analysis?

A. Yes. I used the results from a PA Consulting forecast of MISO hourly prices in Zones 1 and 3. The forecast is an output from the Aurora XMP hourly chronological dispatch model. PA populates the model with assumptions regarding loads, generation, fuel costs, projections of generation additions and retirements, and transmission constraints. I used the forecast of hourly prices in conjunction with the hourly wind production profile to estimate the revenues that the Company will receive from dispatching the Heartland Divide II project into the MISO market. I compared the estimated revenues with the Project's PPA costs. In addition, I made an adjustment for wind integration costs.

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

A. No, it does not.

Q. How did you compare your estimates of the projected energy cost savings to the Company's estimates?

A. I calculated the projected energy savings as the Project's projected revenues less the projected costs. I compared the difference in revenues between the Company's Base Case EnCompass analysis and the revenues from a PA forecast for MISO LMPs, and used the

PPA prices as the costs. Notably, this does not reflect the shifting of resource additions the Company assumed between its "Wind Repower Base A" case and the "Add Heartland Divide – PVRR" case. While I acknowledge that adding the Project as a new resource could shift other generation addition decisions, I also note that the Company's analysis does not reflect the incremental load between the two cases. Consequentially, there are issues with the Company's assumptions regarding the change in resource additions.

Q. Could you please compare your estimates of the projected energy cost savings to the Company's estimates?

A. Yes, Table 3 shows results from my analysis, which reflects the Project's 200 MW. I discounted the annual margins using the same discount rate assumed by the Company (6.47%). My estimate is that the Base Case energy savings could be on the order of 40% lower than the Company's estimates. My analysis also shows how a comparable wind project with the same capacity value and interconnection costs would have significantly higher margins in MISO Zone 1.

Table 3. Independent Economic Analysis Results For the 200 MW Project[22]

Present Value System Cost Savings ($000)	Energy Margins Without Wind Integration	Energy Margins With Wind Integration Costs
PA MISO Zone 3 Analysis	45,035	40,522
PA MISO Zone 1 Analysis	84,618	80,105
NSP EnCompass Analysis	88,599	84,086

Notably, North Dakota customers will benefit from approximately 5% of the savings shown in Table 3.[23]

[22] Assumed wind integration costs from Company 2020-2034 Upper Midwest Resource Plan Supplement: Supplemental Details IV. Modeling Assumptions and Inputs.

[23] The 5% estimate is based on 75% of the Project functioning as a system resource. The North Dakota energy allocation factor, which will vary by year, will be on the order of 6.5%.

Q. What are your conclusions regarding the Company's estimate of $97.4 million of system cost savings from the Project?

A. While the estimate is in the range of reasonableness, the Company's projected savings are likely overestimated due to varying MISO market price assumptions. My independent analysis, using MISO market price assumptions developed by PA Consulting, shows markedly less savings. As shown above in Table 3, I estimated that the Project's savings based upon dispatching the Project into Zone 3 to be approximately $40,000,000 less when comparing to dispatching the plant against PA's MISO Zone 1 prices. When I compared the savings based upon dispatching the wind against PA Zone 1 prices versus the Company's MISO prices, I estimated approximately $4,000,000 less savings.

Q. What amount of the Company's savings estimate would benefit ND customers?

A. NSP proposes to credit 75% of the projected savings to the system power cost calculation. NSP would base North Dakota's share on its percentage of system retail sales. Those two adjustments translate into North Dakota customers' savings of less than $2M on an NPV basis.

Q. Have you evaluated NSP's finding that North Dakota customers will benefit in the allocation of generation demand costs due to adding the data center load?

A. Yes, I reviewed the analysis provided by the Company.[24] The Company's analysis indicates that the data center load would provide [**Trade Secret Begins**] [redacted] [**Trade Secret Ends**] in demand cost savings to North Dakota customers on a NPV basis.

Q. Do you expect that there will be demand cost savings for North Dakota's customers based upon your review of the Company's analysis?

A. Yes; however, the savings will be nominal.

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[24] NSP Response to Advocacy Staff Data Request 2-10.

XII. FCR Accounting for the PPA

Q. Would you please summarize the Company's proposal for addressing the 50 MW costs of Heartland Divide II if the Commission accepts the ADP and the Company's proposed treatment?

A. My understanding is that the Company proposes to address the 50 MW dedicated to Renewable*Connect in the same way that the it treats Disallowed PPAs in the FCR. The energy generated by 25% of the Project will be priced at the system average energy cost.[25]

Q. What is the expected impact of excluding 50 MW of the PPA from treatment as a system resource?

A. If 50 MW of the PPA is excluded, the Company will substitute the average system cost of fuel and purchased power for the actual PPA cost. In the FCR only a portion of the 50 MW is allocated to North Dakota based upon the ratio of the retail sales of North Dakota to the rest of the NSP system. Based upon the average system fuel and purchased power costs developed by the Company in its Base Case, I estimated that it will add approximately $400,000 to North Dakota power costs over the twenty-five-year PPA.

Q. Why should the Commission consider rejecting NSP's request to exclude 50 MW of the PPA from treatment as a system resource?

A. As discussed above, the Commission has not historically approved ADPs when a company fails to demonstrate the resource is least cost and instead requires those resources have separate treatment in the FCR. I believe the policy of separating a resource into a system and non-system resource may be beyond the scope of the ADP.

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[25] System average energy cost is calculated by dividing total fuel and purchased power (less disallowed costs) by total energy sales (less disallowed energy).

Q. How would the PPA be treated in the FCR if the Commission does not approve the ADP?

A. My assumption is that it would be treated similarly to other disputed resources until such time as the Commission ruled on the prudence of the PPA. That ruling would presumably be in the next NSP general rate case. If it were treated as a disputed resource then the cost of the PPA would be removed and the energy from the PPA would be assigned a cost based upon the average system costs where the average system cost excludes all disputed PPAs. If the Company's expectation that the PPA will lower power cost holds, then the impact would be an adjustment upward in the North Dakota assigned power costs to what those power costs would have been were the PPA approved.

XIII. Other Considerations

Q. Did you consider any other issues related to the Project in making your recommendations?

A. Yes. I have comments on three issues related to the PPA:

- The Minnesota Department of Commerce's recommendation (DOC)and the potential that NSP could withdraw the ADP;
- The relationship of the procurement of the Heartland Divide II PPA to the Company's IRP; and
- Treatment of RECs.

Q. Was the DOC currently supportive of the PPA?

A. No, in comments dated February 3, 2021, the DOC recommended the Minnesota PUC reject the PPA because it believes the Company did not follow the Minnesota PUC approved competitive bidding processes.[26] The DOC recommended that the Commission require the Company to follow established bidding processes.

Q. What are the implications of NSP allegedly not following Minnesota's approved bidding process?

A. First, if the Minnesota PUC rejects the PPA then NSP will likely withdraw this request to the North Dakota Commission for an ADP. Second, it is possible that NSP did not select the lowest cost resource as a result of establishing a selection criterion that focused on having a renewable resource online by the end of 2021 with known interconnection costs.

Q. Should the Commission be concerned that NSP did not follow Minnesota PUC's competitive bidding process?

A. The Commission should be concerned NSP is not procuring the resource in response to an IRP-identified need and may not be the lowest cost alternative to meet the NSP system power needs after factoring in risks.

Q. How does the procurement of the PPA relate to the IRP?

A. The EnCompass preferred expansion plan does not include any new wind resources until 2032.[27] While NSP is seeking approval of the Project based on its ability to lower overall power cost, the need for the PPA is driven by the requirements of the Honeycrisp RESA. Essentially, the Commission is being asked to make a resource procurement prudency decision not on the need for a new resource to serve retail load but to reduce power costs by taking a long position in the MISO market.

Q. Is the issue of securing wind resources ahead of need to serve retail load an issue that should be addressed in the IRP?

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[26] Public Comments of the Minnesota Department of Commerce, Division of Energy Resources, Docket No. E002/M-20-806, February 3, 2021.

[27] Section 3: Supplement Preferred Plan, Figure 3-3 page 70.

A. Yes, there are a few issues that could be addressed including: 1) the risk of relying on selling excess energy to MISO as a strategy to lower system power costs; 2) timing of system expansion plans to lower risk; and 3) the degree to which the Company's renewable energy goals are least-cost when factoring in reliability.

Q. Please summarize the Company's proposal with regards to RECs from the Project?

A. The Company has requested that North Dakota will not be compensated for its share of the RECs from the Project. The Company's argument is that even though it is requesting treatment as a system resource, the Project is being acquired to meet its obligations under the RESA.[28] The Company further argues that North Dakota gets additional benefits by the shift in the energy and demand allocation factors.

Q. Do you agree with the Company's requested treatment of the RECs?

A. No. If NSP wants 150 MW of the PPA treated as a system resource, there should be consistent and fair treatment of RECs. North Dakota is paying its full share of the 150 MW of the PPA, so North Dakota's share of the RECs should be monetized for the benefit of North Dakota customers. While the demand allocation factors may change if the data center load is realized, the demand costs will also increase due to the need to acquire more capacity to meet the load plus reserve margin. Consequently, while the demand allocation factor decreases for North Dakota, the total demand costs increase for the system and it is not clear that there is even a net benefit.

Q. What is the Company's position with regards to the cost of purchasing additional RECs ("Cover RECs") to meet the terms of the RESA?

A. The Company indicated that North Dakota customers should not be held harmless if the Company needs to purchase additional RECs to meet the terms of the RESA.[29]

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[28] Prefiled Direct Testimony of Mr. Shaw p 13. line 6 – 13.
[29] Pre-Filed Direct Testimony of Mr. Shaw p 15 lines 4- 12.

Q. Do you agree with the Company's recommended treatment of the cost of any Cover RECs?

A. No. The Company has entered the Honeycrisp RESA. The terms of that contract, as well as NSP retail rates, are not subject to this Commission's review. The Company's request to ask North Dakota customers to potentially share in the cost of Cover RECs is akin to North Dakota expecting Minnesota customers to subsidize a North Dakota special retail rate contract. Neither jurisdiction subsidizes the retail rates of the other jurisdiction.

Q. What is your recommendation regarding the treatment of RECs associated with the PPA as well as any RECs that the Company may need to purchase to meet its obligations under the Honeycrisp RESA if the Commission approves the ADP request?

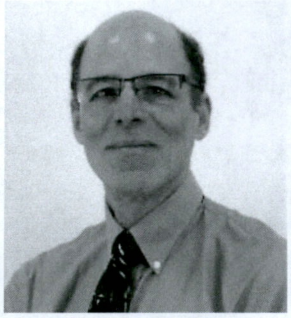
A. If the Commission approves the request, I recommend the Commission impose similar conditions on approving the Heartland Divide II PPA as it did for the Dakota Range III PPA. These conditions are:

- North Dakota customers should receive their proportional share, based upon the energy allocation factor, of the RECs from the 150 MW of the PPA that is designated as a system resource; and
- North Dakota customers should not bear any of the costs associated with the Company procuring RECs to meet the terms of the RESA.

Q. Does this conclude your testimony?

A. Yes.

Exhibit____JAH-1
PU-20-433



JIM HEIDELL

DIRECTOR

Jim Heidell specializes in electric and gas utility regulation, distributed energy, 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. He has extensive financial and energy market modeling experience coupled with a deep understanding of regulated and competitive markets that he applies to the valuation of energy assets. Mr. Heidell has prepared and submitted testimony in both regulatory proceedings and civil contract damages cases. His regulatory experience and testimony includes rate design, cost of service, resource planning, and merger conditions. Mr. Heidell also specializes in strategic analysis and evaluation of opportunities associated with renewable / alternative energy technologies. Prior to working at PA Consulting he held positions as the Director of Finance and Director of Federal and State Regulation at Puget Sound Energy. Mr. Heidell is a CFA and has an MBA in finance from the University of Washington, a MS in Engineering Economics from Stanford University, and a BSE in civil engineering from Tufts University.

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

CLIENTS

- Riverstone Holdings
- Puget Sound Energy
- Solarcity
- Comision Federal de Electricidad
- North Dakota Public Service Commission

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

EXPERIENCE SUMMARY

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

- **Evaluation of Distributed Energy and Behind the Meter Generation** – Forecast of margins of community solar projects, portfolios of customer sited PV projects, and analysis of regulatory policies and rules associated with community solar projects and behind the meter PV projects.
- **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.
- **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.

EXPERIENCE

CIVIL LITIGATION TESTIMONY & SUPPORT

Rebuttal of claims of economic damage associated with the cancellation of a water desalination project in Monterey California.

Prepared an analysis of claims of economic damage associated with the performance of an anaerobic digester designed to provide gas for an electric generation project. Analysis included evaluation of performance, revenues and costs, and cost of capital used to discount projected future earnings. Prepared expert report and testified in jury trial in federal district court.

Developed an analysis of material and labor cost increases on EPC costs for a natural gas fired power plant located in New Mexico. The analysis was used to refute a claim that cost overruns were not reasonable in a cost plus EPC contract. The analysis demonstrated how much of the total project cost increases was associated with labor and material costs beyond the control of the general contractor.

Prepared an analysis of loss of margins at two coal plants during periods when there were alleged violations of EPA opacity emission limits. The analysis demonstrated that client did not receive any economic benefit associated with the periods of alleged violations.

Prepared an analysis of the commercial distributed solar sector in the 2010 – 2011 time frame and demonstration of the unreasonableness of the plaintiff's claims for economic damages associated with the defendant's decision not to pursue participation in an equity fund.

Prepared an analysis of the U.S. wholesale electric power markets in the 2008 – 2010 time frame to demonstrate why the plaintiff's decision to terminate construction of a coal fired power plant was due to cost increases in the EPC contract and not due to the changing natural gas prices and emission laws.

Prepared an estimate of lost margins associated with the extended outage of a Canadian nuclear reactor. The analysis included an estimate of what Ontario wholesale power prices would have been but-for the outage and estimates of the total damages including repair and inspection costs.

Prepared an Expert Report regarding rate making and financial policies of the Southern Minnesota Municipal Power Agency in conjunction with a contract dispute regarding a power contract and investments in new generation resources to serve full requirements customers.

Assisted expert witness by the preparation of a report on how a third party would value the Trans-Alaska Pipeline as part of a property tax dispute with the municipality of Anchorage.

Prepared an analysis of damages associated with claims for losses associated with the interruption of business of a Texas gas-fired power plant as a result of the rupture of a natural gas pipeline use to supply the power plant.

Prepared of an analysis of the economic benefits that accrued to the defendant associated with the purported delay of implementation of measures to correct water pollution discharge violations associated with a power plant.

ANALYSIS OF RENEWABLE ENERGY INVESTMENTS

Preparation of multiple Independent Market Expert Reports to support financing of community solar projects in Illinois, Maine, Massachusetts, New York, New Jersey, and Maryland.

Prepared an Independent Market Expert Report to support the debt financing of BrightSource Energy's Ivanpah solar thermal projects with purchased power agreements with California investor owned utilities.

Prepared an Independent Market Expert Report to support the debt financing of Solona, a large solar thermal project with molten salt storage, with a purchased power agreement with an Arizona Public Service.

Prepared an Independent Market Expert Report to support the expansion of a CdTe PV manufacturing facility in Colorado including the analysis of the business plan and projection of long-term prices for the PV modules.

Prepared an Independent Market Expert Report to support the expansion of a c-Si PV manufacturing facility including the analysis of the business plan and projection of long-term prices for the PV modules.

Prepared an Independent Market Expert Report to support the expansion of a polysilicon manufacturing facility including the analysis of the business plan and projection of long-term prices for polysilicon and the associated raw materials.

Prepared an evaluation of the global market for concentrating solar power plants as of 2012 as part of a client analysis of a potential purchase of a solar mirror manufacturing company.

Prepared an evaluation of the U.S. solar PV market to support evaluation of a Japanese firm's potential expansion in the U.S. markets.

Assisted client with a bid into a utility's renewable energy procurement program. The analysis included an assessment of competitors and analysis of pricing to support the bid of a renewable energy resource into 2011 Entergy RFP for renewable resources.

Prepared long range forecasts of multiple wind portfolios with an emphasis on the valuation of post PPA revenues and the value or renewable energy credits.

Prepared an analysis of the market for future expansion of the wind business of a major U.S. wind developer based upon an assessment of the competitiveness of wind generation with gas fired generation.

Prepared a fair market value analysis of associated with the purchase of a minority position in a wind project located in Ontario, Canada.

Prepared an Independent Market Expert Report to support the debt financing of a geothermal power project located in the Pacific Northwest.

Prepared an Independent Market Expert Report to support the debt financing of the Beacon flywheel energy storage project in New York.

Prepared an Independent Market Expert Report to support the debt financing of the AES battery energy storage project in New York. Development of an Independent Market Expert Report to support the financing of the Kemper IGCC plant including an analysis of the regulatory structures being relied upon to support cost recovery as well as wholesale electric prices to support wholesale power sales.

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.

M&A and BANKRUPTCY ADVISOR

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.

ASSET APPRAISALS

Prepared a valuation of a large eastern coal plant as a third party appraiser required in a transaction where the lessee wanted to exercise a buy-back provision in a sale lease-back agreement.

Prepared a valuation of a California cogeneration plant for the purposes of identifying the tax loss.

Completed an appraisal to support the transfer of the Trans Bay Cable from the development arm to a separate fund managed by the infrastructure fund. The appraisal addressed the California power markets, operations of the CA ISO high voltage transmission and a forecast of revenues given the FERC and CA-ISO regulatory schemes as part of the income approach. The appraisal also incorporated a comparable sales and replacement cost analysis.

Developed an appraisal of a nuclear power plant based upon discounted cash flow, replacement costs, and comparable sales as part of an effort to determine the fair market value under a lease agreement that contained a buy-back provision.

Completed multiple appraisals of the KeySpan generation assets on Long Island that were subject to a generation repurchase agreement with LIPA. The appraisals were part of the ongoing process for KeySpan to develop a strategy to address the LIPA repurchase option.

Development of an Independent Market Expert Report to support the financing of the Kemper IGCC plant including an analysis of the regulatory structures being relied upon to support cost recovery as well as wholesale electric prices to support wholesale power sales.

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 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.

ELECTRIC MARKETS RISK MODELING

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.

DSM ADVISORY SERVICES

Advised Con Edison on the status of electric decoupling and incentive mechanisms in the United States as part of the New York state initiative to reintroduce decoupling.

Advised a private equity fund on the status of demand side management in New England, likely projections of growth, and probability of successful implementation as part of an evaluation of long-term supply and demand conditions in the New England electric markets.

Worked with Montana-Dakota utilities regarding the incorporation of projections of demand side management potential into the utility's long-term resource plan.

ADDITIONAL EXPERIENCE – EXPERT TESTIMONY

California-American Water Company, a California Corporation; Monterey County Water Resources Agency, Plaintiffs, vs. Marina Cos Water District; RMC Water and Environment, a California Corporation; and DOES 1 through 10, inclusive, Defendants, Case No. CGC-15-546632. Report and Deposition on behalf of RMC Water and Environment addressing alleged economic damages as a result of a cancelled desalination project.

Before the Hawaii Public Service Commission, Direct Testimony Of James A. Heidell, Docket No. 2017-0105 In The Matter Of The Application of Hawaii Gas Company Application for a General Rate Increase. Testimony on behalf of Hawaii Gas addressing rate spread and rate design.

Before the North Dakota Public Service Commission, Direct Testimony and Schedules of James A. Heidell, In the Matter Of Otter Tail Power Company Advance Determination of Prudence Astoria Natural Gas Project, Merricourt Wind Project and Certificate of Public Convenience and Necessity Merricourt Wind Project, Case Nos. PU-17-140, PU-17-141, & PU-17-143,

Before the North Dakota Public Service Commission, Direct Testimony and Schedules of James A. Heidell, In the Matter Of Northern States Power Company Advance Prudence – Dakato Range Wind Project, Case No. PU-17-372.

Before the North Dakota Public Service Commission, Direct Testimony and Schedules of James A. Heidell, In the Matter Of Northern States Power Company Advance Prudence – 1,550 MW Wind Portfolio, Case No. PU-17-120.

Before the North Dakota Public Service Commission, Direct Testimony and Schedules of James A. Heidell, In the Matter Of Northern States Power Company Advance Prudence – BIOMASS APPLICATION FOR DEFERRED ACCOUNTING, Case Nos. PU-17-270, PU-17-271, & PU-17-322.

Before the North Dakota Public Service Commission, Direct Testimony and Schedules of James A. Heidell, In the Matter Of Northern States Power Company A Minnesota Corporation D/B/A XCEL Energy Jurisdictional Cost Allocation Matters, Case Nos. PU-12-813 et. al.

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.

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.

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.

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.

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Northern States Power Company
Advance Prudence – 200 MW Heartland Divide Wind II Application

Case No. PU-20-433

VERIFICATION

STATE OF _____CO _____)
) ss.
COUNTY OF __SUMMIT ___)

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 matters 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

Subscribed and sworn to before me this 30 day of March, 2021.

Notary Public
My Commission Expires: Jul 1, 2024

SALVADOR I MIRANDA
NOTARY PUBLIC - STATE OF COLORADO
NOTARY ID 20204022957
MY COMMISSION EXPIRES JUL 1, 2024