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December 17, 2021

VIA EMAIL AND HAND-DELIVERY

Public Service Commission
Attention: Steve Kahl
600 East Boulevard Avenue, Dept. 480
Bismarck, ND 58505-0480

In re: Northern States Power Company
460MW Solar – Sherburne Cnty, MN
PU-21-152

Dear Mr. Kahl:

Enclosed for filing in the above-referenced matter please find the original and seven copies of the following **Public Documents**:

1. Direct Testimony of James Heidell (Public Version);
2. Exhibit JAH-1;
3. Exhibit JAH-2 (Public Version);
4. Verification; and
5. Affidavit of Service.

Pursuant to the October 21, 2021, *Order Granting Trade Secret Protection,* we are also enclosing one copy of the following documents in a sealed envelope labeled "**PROTECTED INFORMATION/TRADE SECRET – PRIVATE**" the following documents:

1. Direct Testimony of James Heidell (Non-Public Version); and
2. Exhibit JAH-2 (Non-Public Version).

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18 PU-21-152 Filed 12/17/2021 Pages: 46
Prefiled Direct Testimony of James Heidell - redacted
Public Service Commission
Mitch Armstrong, SAAG

Thank you for your attention to this matter.

Respectfully,

MITCHELL D. ARMSTRONG
Special Assistant Attorney General for PSC
Advocacy Staff

amh
enclosures
cc: ALJ Timothy Dawson (via U.S. Mail, w/ public enc. only)
Zeviel Simpser (via U.S. Mail, w/ public enc. only)
John Schuh (Via U.S. Mail, w/ public enc. only)

PSC.3

Public Document

Trade Secret Data Redacted

TESTIMONY

JAMES A HEIDELL

STATE OF NORTH DAKOTA

BEFORE THE

NORTH DAKOTA PUBLIC SERVICE COMMISSION

NORTHERN STATES POWER COMPANY CASE NO. PU-21-152

ADVANCE DETERMINATION OF PRUDENCE – 460 MW SHERCO SOLAR FACILITY

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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 have submitted testimony on behalf of Advocacy Staff in numerous dockets including the following:

- Northern States Power Company's request for an ADP for the Heartland Divide II Wind Project (Case Number PU-20-433);
- 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 (CT) (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) Application for an Advanced Determination of Prudence (the Application) for the 460 MW grid-scale solar photovoltaic (PV) facility at the Company's Sherburne County (Sherco) Generation Station site (Sherco Solar, or the Project). The Project consists of two distinct large solar facilities in Becker, Minnesota adjacent to the existing Sherco coal plant. This Advanced Determination of Prudence (ADP) request is unique in that the Company is not asking the Commission for an ADP of the solar project, but rather to approve a proxy pricing scheme developed by NSP. According to the Company, its proposed proxy pricing will result in a lower cost to North Dakota ratepayers than obtaining an equivalent amount of energy and accredited Midcontinent Independent System Operator (MISO) capacity. NSP contends the Project is the least cost option when incorporating Minnesota's assumptions related to the social cost of carbon; however, when the social cost of carbon is not included the analysis, per the requirements of North Dakota, the lowest cost capacity resource is a CT.

The Company indicates that its 2020-2040 Upper Midwest Resource Plan Supplement (IRP) identified the need for new capacity in 2026 due in part by the need to replace the capacity from the Sherco Unit 2 coal plant scheduled for retirement in 2023.[1] The IRP's Preferred Plan, based upon Minnesota planning criteria, identified a solar resource as the most cost-effective resource; however, the IRP's North Dakota Scenario – the "North Dakota Plan" – identifies a 374 MW CT in 2025 as the most cost-effective resource.[2] [3]

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 followed by a detailed discussion of my supporting analysis and additional factors considered. Finally, I propose conditions for the Commission to consider imposing if it approves the Company's request for a proxy pricing treatment. My testimony is separated into eleven sections:

- A summary of my recommendations (Section III);
- A summary of my findings (Section IV);
- An overview of the Project (Section V);
- An overview of the requested proxy pricing treatment (Section VI);
- An assessment of the need for additional capacity (Section VII);
- An evaluation of the economics of the Project (Section VIII);
- An evaluation of the economics of the proxy pricing (Section IX);
- Consideration of additional issues (Section X), and
- My conclusions and recommendations (Section XI)

Q. Are you sponsoring any exhibits to your testimony?

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[1] Application Page 1.

[2] Upper Midwest Integrated Resource Plan 2020 -2034 Supplement, Northern States Power Company, Docket No. E0002/RP-19-368

[3] The Preferred Plan identifies 500 MW of new solar on-line in 2025 (3-2)

A. Yes, I am sponsoring two exhibits:

- Exhibit JAH-1: James Heidell CV; and
- Exhibit JAH-2: Forecast of Net Energy Margins from a CT.

III. Summary of Recommendations

Q. Do you recommend the Commission approve the Company's request for approving proxy pricing in place of the Project?

A. No, I recommend disapproval of the ADP with regard to either the Company's request for proxy pricing, or for acquiring the Sherco Solar project in lieu of proxy pricing.

Q. If the Commission were to approve the Company's request for approving proxy pricing, are you recommending modifications?

A. Yes, as conditions to any Commission approval of proxy pricing, I recommend that the Commission:

- Set the proxy cost of capacity equal to the cost of a brownfield CT assumption as defined in the most recent Supplemental IRP;
- Adjust the proxy capacity cost to reflect an offset for the expected energy market margins the brownfield CT would earn in the MISO energy markets.
- If the Commission accepts NSP's recommendation to base capacity cost on the MISO Cost of New Entry (CONE), the MISO CONE should be adjusted downward to reflect the gross margins that the CT would earn in the energy and ancillary services market as those margins would be credited to customers (Net-CONE).
- Clarify that ND customers will only pay for the actual accredited capacity that is relevant to the Project as determined by the MISO and adjust ND customers' share based upon the prevailing cost allocation factors;
- Explicitly exclude ND customers from any future renewable integration costs assigned to the Project by MISO;
- Require periodic review of the commitment for ND customers to pay a load-based share of the energy from the Project at MISO rates; and

- Establish that the approval is non-precedential.

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. My conclusion is that the Company is offering a false choice to the Commission. The Commission is not being offered the choice of selecting between the Project or a CT; NSP's intention is to add 460 MW of solar to its resource portfolio, regardless of the Commission's ADP decision. NSP anticipates the Commission will reject sharing in the cost of the Project but is nonetheless requesting the Commission resolve the accounting for a disputed resource through a potentially precedent setting ADP decision. While it is the prerogative of the Commission to establish the accounting in conjunction with rejecting an ADP, I am not aware of instances in prior ADP requests where this Commission has ordered an accounting treatment for a disputed resource.

Q. If the Commission concurs with your recommendation to reject the ADP for the Project, why should the Commission also reject the proxy pricing proposal?

A. My understanding is that this Commission's precedent is that if it rejects an ADP for a company-owned renewable resource, that those costs should not be recovered through the Renewable Energy Rider and capacity cost recovery is explicitly excluded in the Fuel Cost Rider.

Q. Do you have additional specific findings?

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 relevant in determining whether to approve the ADP for the Project and/or the proposed proxy pricing:

- If the Commission approves a proxy pricing mechanism, it should require NSP to modify its proposed methodology.

- The basis for the proxy price should be the cost of the combustion turbine less the energy and ancillary margins (Net CONE).
- The Company should allocate North Dakota's share of capacity costs based upon the Project's accredited capacity in each year and that year's prevailing inter-jurisdictional capacity allocation factor.
- North Dakota customers should not be allocated a share of the transmission costs used to connect the two solar facilities to the existing substation.

- NSP's need for additional capacity is based upon its load forecast, the end of the Manitoba Hydro contract, and decision to retire the Sherco coal units early. However, absent the Company's decision to retire the Sherco coal units early, the need for the capacity would be delayed for years;
- NSP does not have a retail load need in this decade for the energy the Project will generate;
- There is no benefit to North Dakota customers associated with a long-term commitment to purchase electricity at volumes tied to the Project's output and costs based on MISO market pricing. The Company can purchase power for ND customers from MISO at the prevailing market price without any long-term contractual commitment.

V. Overview of the Project

Q. Would you please provide an overview of the Company's plan to construct Sherco Solar?

A. The Company plans to build 460 MW of solar adjacent to the existing Sherco coal plant. The Project consists of: (1) a 230 MW solar project under development by National Grid Renewables located to the west of the coal plant (National Grid project) and (2) a 230 MW solar project being developed by NSP on the east side of the coal plant (NSP project). The Company will also build two short high-voltage transmission lines to connect the projects to the existing Sherco substation. The west block will be on land leased by National Grid and the east block is on land leased by Xcel. The Company plans to acquire the National Grid project through a build-own-transfer arrangement. The anticipated COD for the Project's full capacity is projected to occur in the fourth quarter of 2024 with an estimated cost of $622M ($586M without AFUDC).[4]

Q. Will NSP have to build new transmission facilities to connect the Project?

A. Yes, the Company will need to make a relatively small investment to interconnect each of the Project's two solar facilities to the Sherco substation.[5] Contingent upon NSP interconnecting alternative generation within three years of the date that Sherco Unit 2 ceases operation, however, MISO rules permit NSP to retain Sherco's existing transmission interconnection rights.[6]

Q. What is the Company's estimate of Project cost?

A. The Company estimates total cost including AFUDC will be **[Trade Secret Begins]** [redacted] **[Trade Secret Ends]**. Based upon Company modeling, this translates to **[Trade Secret Begins]** [redacted] **[Trade Secret Ends].** The Company expects that based upon current rules, the Project will also qualify for an Investment Tax Credit (ITC) of **[Trade Secret Begins]** [redacted] **[Trade Secret Ends]**.

Q. Does the Company's capital cost estimate include transmission costs?

A. Yes, the estimate includes **[Trade Secret Begins]** [redacted] **[Trade Secret Ends]** excluding AFUDC. The cost is for two short connection lines and interconnection to the existing substation.

Q. Is the Company requesting that the NDPSC approve the Project?

A. No. The Company is *not* asking the Commission to approve the Project because its

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[4] NSP Public response to IR No. 2, E002/M-20-891.
[5] Direct Testimony of Chamberlain p 12 line 20.
[6] MISO Tariff, Attachment X, Section 3.7.1.

analysis does not identify the Project as the least cost capacity resource addition when the analysis excludes an assumed social cost of carbon.[7] The Company is instead asking the Commission to "institute a cost assignment methodology"[8] that permanently approves a specific proxy pricing methodology for valuing the energy and accredited capacity associated with the Project.

VI. Summary of the Proxy Pricing Proposal

Q. Would you please provide an overview of NSP's proposal for assigning North Dakota a share of the energy and capacity from the Project using proxy pricing?

A. Yes, the Company is proposing that North Dakota's pro rata share of the MISO accredited capacity from the Project be based upon the cost of a CT as defined by MISO in its published CONE as of 2023/24.[9] North Dakota's pro rata share of the energy cost would be recovered through the Fuel Cost Rider (FCR) based upon the hourly nodal price that the resource is paid by MISO.

Q. Is there a North Dakota precedent for the Company's proposal for allocating the energy cost of the Project?

A. No, not that I am aware of. I note that there is precedent for the Company recovering disallowed PPAs. As I discuss below, there is precedent for using proxy pricing to recover an equivalent amount of energy from disallowed PPAs in the FCR. In this instance the Project is not a PPA, and the Company is proposing to recover capacity costs through the FCR.

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[7] The assumed social cost of carbon is established by the PUC in Minnesota Public Utilities Commission's Order Updating Environmental Cost Values in Docket No. E999/CI-14-643 issued January 3, 2018

[8] Direct Testimony of Chamberlain p 15 line 18.

[9] The Company uses the MISO CONE cost as of 2020/21 in this filing, but the proposal is to use the 2023/24 cost when that is determined.

Q. Is the Company's proposal similar to the approach the Commission has addressed prior disputed resources?

A. With respect to the energy costs, the Company's proposal is similar to – but not exactly the same as – the approach that has been used for the treatment of the Minnesota Community Solar Gardens disputed resources in the FCR. While I am not aware of the Commission explicitly approving the approach for those disputed resources, it has been the practice for years. The Company's proposal is different in that the Community Solar Gardens disputed resources are priced at MISO average costs for the month but not tied to the disputed resource's nodal price.

Q. Is there a North Dakota precedent for the Company's proposal for allocating the capacity cost of the Project in the FCR?

A. No, not that I am aware of. However, I note that a reading of the FCR explicitly includes PPAs and explicitly excludes recovery of capacity costs.

> **QUALIFYING SYSTEM COST OF FUEL**
> The qualifying system cost of fuel includes:
> 1. The cost of fuels consumed in the Company's generating stations as recorded in Federal Energy Regulatory Commission (FERC) Accounts 151 and 518;
> 2. The cost of energy purchases, exclusive of capacity or demand charges, as recorded in FERC Account 555 including but not limited to:
> a) Energy that is purchased on an economic dispatch basis;
> b) Energy purchased from a renewable energy source with the exception of the Purchased Power Agreement (PPA) Cost Exclusion defined below. The energy that would have been provided to North Dakota customers from these excluded PPAs will be repriced at the Qualifying System Cost of Fuel absent these contracts;
> [Tariff Section 5 5th Revision Sheet No. 76]

Q. Is there a North Dakota precedent for the Company's proposal for allocating the capacity cost of the Project in the Renewable Energy Rider (RER)?

A. No, not that I am aware of. My understanding is that the RER is used for approved Company-owned renewable resources that are not included in rates. I am not aware of a precedent for using proxy pricing in the RER for disallowed Company-owned resources.

Q. Does the Company's proposal for proxy pricing in the RTF Proceeding create a precedent for the Company's current proposal?

A. No. Mr. Chamberlin notes the Company's current proposal is consistent with its proposal for proxy pricing in the RTF filing;[10] however, neither Advocacy Staff nor the Commission accepted the Company's proposal. Furthermore, Advocacy Staff highlighted numerous concerns with the Company's RTF filing.

Q. If the Commission approves including capacity cost recovery in either the RER, or FCR, is basing the proxy cost for capacity based upon a CT reasonable?

A. Yes, if the Commission is considering a mechanism for proxy capacity pricing where there is a legitimate demonstration of need for additional capacity resources but not additional energy resources. The Company uses the CT as its firm dispatchable peaking resource in its EnCompass modeling for its IRP. As the CT would be the alternative capacity resource, it is a reasonable proxy for the cost of acquiring additional capacity.

Q. How does the Company propose to estimate the proxy capacity cost based upon a CT?

A. The Company is proposing to use the CONE, as defined by MISO in the 2024-2025 planning year. The Company considered four options for the proxy cost of capacity:

- MISO CONE;
- A generic brownfield CT;
- The Mankato Energy Center II PPA (MEC II PPA); and
- Estimated cost of maintaining the Sherco II coal plant and keeping it in service through 2024 and then constructing a CT.

The Company concluded that MISO CONE is the best option.

Q. Do you agree with the Company's recommendation?

A. No. If the Commission allows the use of a proxy, my recommendation is that the Company use the brownfield CT cost, as estimated in the Supplemental IRP.

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[10] Direct testimony of Mr. Chamberlin p 19, lines 25 – 26.

Q. How does MISO determine the CONE?

A. MISO bases its estimate for a CT on an estimate from the U.S. Department of Energy's (DOE) Energy Information Administration (EIA) as part of its annual long-term Annual Energy Outlook. MISO then scales the cost for each Local Resource Zone (LRZ) using a regional factor. The MISO tariff states:

> *[C]onsider factors, including, but not limited to: (1) physical factors (such as, the type of Generation Resource that could reasonably be constructed to provide Planning Resources, costs associated with locating the Generation Resource within the Transmission Provider Region, the estimated costs of fuel for the Generation Resource); (2) financial factors (such as, the hypothetical debt/equity ratio for the Generation Resource, the cost of capital, a reasonable return on equity, applicable taxes, interest, insurance); and (3) other costs (such as, costs related to permitting, environmental compliance, operating and maintenance expenses). In calculating the CONE, the Transmission Provider and the IMM shall not consider the anticipated net revenue from the sale of capacity, Energy or Ancillary Services. CONE values will be calculated for each LRZ.*[11]

Q. What are some of the issues with using the MISO estimate of CONE costs?

A. There are a number of issues with using the MISO cost estimate as the proxy cost for North Dakota. These issues include:

- The EIA cost estimate is based upon a November 2016 study using April 2016 data. Ignoring inflation, it does not necessarily reflect current costs;[12]

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[11] MISO FERC Electric Tariff, 69.A.8, Calculation of CONE, 33.0.0 Tariff (misoenergy.org)
[12] https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capcost_assumption.pdf

- The regional adjustment factors used by MISO refer to the EIA adjustment factors from the November 2016 study;
- MISO bases CONE on a greenfield project; however, NSP has not demonstrated why a brownfield project is not a reasonable capacity proxy;
- In the past the Company has identified the Sherco site as a brownfield site for a combined cycle and NSP has identified multiple other sites as a possibility for a brownfield CT;
- The estimate uses a hypothetical capital structure and not NSP's capital structure, and
- The estimate excludes the MISO energy and ancillary service margins that North Dakota customers would have otherwise received if the CT were constructed.

Q. What capital structure is incorporated into the MISO CONE analysis?

A. MISO's CONE analysis uses the following assumptions regarding capital structure: a 55/45 debt to equity ratio; a 20-year project life and loan term; a 6.20 % debt interest rate; and a 13.4% after tax internal rate of return on equity.[13] This results in a weighted average cost of capital (WACC) of 8.52%.

Q. What WACC does the Company assume in its analysis of options in the IRP?

A. The Company uses a 6.47% WACC.[14] My recommendation is that the levelization of the CT cost use the Company's currently approved WACC.

Q. How did the Company determine the capital cost of the brownfield CT?

A. The Company based the brownfield CT capital costs on the assumptions for an advanced 7H turbine in the IRP. The brownfield CT has a capital cost of $467/kW ($2018) compared to $517/kW ($2018) for a greenfield CT. A brownfield CT has a $50/kW

[13] *Filing for Midcontinent Independent System Operator, Inc. Regarding Local Resource Zone CONE Calculation,* Docket No. ER19-2781, p 5.

[14] EO-6-10-21 – ND Plan.xlsb

(2018) cost reduction compared to the greenfield CT.[15] The driver of the cost differential is that the greenfield CT has an interconnection cost of $200/kW over the planning period whereas a brownfield CT has none.

Q. Is it reasonable to assume that the Company can build a CT at a brownfield site?

A. Yes, the Company notes that the retirement of the Sherco coal plant will create 700 MW of interconnection capacity that can be reassigned to new units at the site if a new resource is constructed within three years. In its IRP, the Company identified the Sherco site as a potential brownfield construction site for a combined cycle project and assumes no electric transmission costs. Alternatively, the Company has identified three alternative sites with interconnection rights.[16]

Q. How did the Company determine the capital cost of capacity based upon the Mankato Energy Center (MEC) II PPA?

A. The Company developed the cost estimate based upon the MEC II PPA. The MEC II project consisted of the installation of an additional CT at the existing combined cycle facility. The Company notes; "the MEC II PPA provides a reasonable baseline for the Company's actual costs of firm dispatchable capacity."[17] The Company's estimate for MEC II costs (on a $/kW basis) is above the Company's estimate for a brownfield CT but still below the MISO CONE cost.[18] This further demonstrates that using MISO CONE as a proxy capacity cost overstates the cost of incremental CT capacity developed by / for NSP.

Q. How did the Company determine the cost of capacity based upon the continued operation of Sherco Unit 2 and switching to a CT in 2035?

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[15] 2020-2034 Upper Midwest Resource Plan Supplement, p 69.
[16] NSP response to Advocacy Staff 3-1 C.
[17] Direct testimony of Ms. Mandich, p 9 lines 25 – 26.
[18] NSP response to Advocacy Staff 2-004 Attachment B TRADE SECRET, tab "Capacity Pricing Options."

A. The Company calculated the levelized cost of Sherco Unit 2 capacity over the period of 2020 – 2034 incorporating the revenue requirement associated with the invested capital plus the assumptions about the fixed O&M costs. The Company assumed the cost of a brownfield CT starting in 2035.[19]

Q. Do you agree with the Company's recommendation to use MISO CONE as an estimate for the capital cost to be used in the proxy pricing calculation?

A. No, the more appropriate proxy is the brownfield CT cost identified in the Upper Midwest IRP. The Company has developed a specific cost estimate in its IRP based upon its expertise, and presumably the expertise of its consultants. There is no reason to assume that the EIA's national cost estimate – dating back to 2006 – is a more reasonable basis. In addition, use of the Company's cost of capital is more appropriate.

Q. Why do you recommend use of the brownfield CT?

A. The Company has identified the Sherco site as a location for a brownfield gas generation project and noted the Company can use the available transmission capacity resulting from the coal plant retirement without incurring additional expenses. Furthermore, the IRP cost assumptions reflect the Company's estimate of costs using the Company's cost of capital, which is lower than that assumed in the MISO's CONE calculations.

Q. Do you agree with the Company's proposal to base the proxy cost on the estimated cost in 2024 - 2025?

A. No. My recommendation is to estimate cost at the time the resource would have been constructed – not a forward-looking estimate at the time the unit will be in service. I do not know whether using the current cost will ultimately be higher or lower than the estimated cost in 2024 - 2025.

[19] NSP response to Advocacy Staff 2-4.

Q. If the Company were to build a CT would it provide benefits in addition to capacity?

A. Yes, the CT would be dispatched into the MISO market to provide energy and ancillary services. Furthermore, the CT provides a hedge against high energy costs in hours of scarcity. In addition, it can provide other grid services including frequency regulation, spinning reserves, voltage control, and potentially black start capability. The Company notes the difference in the resource attributes between a CT and solar in the following graphic.[20]

Figure VI-1: Resource Attributes Mapped to Resource Types

		Resource Types	**Firm Traditional – Baseload**	**Firm Traditional – Intermediate or Peaking**	**Variable Renewables**	**Fast-Burst Balancing**
Resource Attributes	**Response Duration & (Frequency of Need)**	***Examples***	*Coal, Nuclear, Biomass, Run-of-river Hydro*	*CC, CT*	*Standalone Wind, Solar*	DR, *Standalone Battery Storage*
Essential Reliability Services	Minutes – Milliseconds (Continuous)	*Spinning reserve, inertial response, frequency regulation, voltage control*	Nuclear Non-nuclear			
Flexibility	Minutes – Hours (Daily)	*Ramp rates, cycling, minimum runtime*				
Energy Availability	Hourly - Multiday (Continuous)	*Long duration availability, secure fuel supply*				
Black Start	Minutes – Hours (Infrequent, emergency only)	*Starts and runs on zero load, secure fuel supply*	Nuclear Non-nuclear			

Q. Would the CT earn positive margins in the MISO market from selling energy and ancillary services?

A. Yes, it is reasonable to expect the Company would earn revenues from dispatching a CT into the MISO market. Those revenues would offset the cost of fuel and variable non-fuel

[20] 2020-2034 Upper Midwest Resource Plan Supplement, P 94, June 30, 2020.

operating expenses as well as a portion of the fixed cost of owning and operating the CT. The offsetting gross margins subtracted from the fixed cost is referred to as the Net CONE.

Q. Does the Company's proxy pricing proposal incorporate the concept of Net Cone?

A. No, the Company's estimate of the brownfield CT cost does not include an offset for margins in the MISO energy and ancillary services markets. As a result, the Company overstates the net cost of the proxy capacity resource.

Q. How would the energy and ancillary services margins be recognized if the Company were to build a CT?

A. My assumption is associated fuel cost and MISO revenues would flow through the FCR, which would result in a net reduction to fuel costs needing to be recovered in rates.

Q. If the Commission does not reject the ADP and accepts your recommendation to use Net CONE as the proxy cost of a CT, how should the offset for energy and ancillary services margins be calculated?

A. My recommendation is to deduct the annual forecast of margins on a $/kW basis from the annual levelized Gross CONE.

Q. How would the annual forecast be established?

A My recommendation, which would be administratively efficient, is to base the forecast on PA's forecast of gross margins on a $/kW basis.

Q. Did you consider using the estimate of gross margins for the CT from the Company's EnCompass Modeling?

A I evaluated that option and rejected it because the Company's modeling of revenues is based upon the dispatch of the Company's resources and not all of the MISO resources. The market price that the CT would receive in each hour of operation is based upon the marginal unit dispatched in MISO to serve the MISO zone and not the marginal unit in NSP's portfolio.

Q. Have you developed the forecast of the CT gross margins based upon participation in the MISO market?

A Yes, it is provided in Exhibit JAH-2. I recognize that as a forecast, it would inevitably be different than what would have occurred had the CT been constructed. However, I note that the adjustment to the gross CONE value is relatively small – on the order of 0.1% – and the alternative of monthly adjustments in the FCR would be overly burdensome.

VII. Demonstration of Need

Q. Has NSP demonstrated a need for the capacity from the project?

A. The Supplemental 2020-2034 Upper Midwest IRP identifies a need for 92 MW of capacity in 2026, 334 MW in 2027 and growing to 1,016 MW in 2030.[21] It should be noted that a significant portion of the need for capacity is a result of the Company's decision to retire Sherco Units 1 and 2 early.

Q. In the North Dakota plan what was the in-service year for the CT?

A. The North Dakota plan indicated that a 374 MW CT would be in-service no later than December 31, 2025. I note that in the EnCompass run provided by NSP, the in-service year is 2027 for 374 MW of capacity.[22] The bulk of the accredited capacity from Sherco Solar will not be needed until 2027 or two years after the expected in-service date for the full capacity of the Project.

Q. What is your understanding of the driver of the need for additional capacity?

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[21] 2020-2034 Upper Midwest Resource Plan Supplement, p 25, June 30, 2020. Supplemental IRP Table 2-2, p 25 of 78.

[22] EO -6-10-21 – ND Pln.xlsb

A. The Company's Supplemental Preferred Plan has several changes to the resource portfolio besides the Project. The driver of the need for new capacity is primarily the expiration of a 450 MW hydro contract with Manitoba Hydro and retirement of resources, including the Sherco coal units, as opposed to load growth. For example, the Preferred Plan includes the retirement of all coal generation by 2030 (i.e., 682 MW of Sherco 2 at the end of 2023 and 680 MW of Sherco 1 at the end of 2026).[23]

Q. Did you independently evaluate the need for new capacity?

A. No, I did not; however, I reviewed the Supplemental IRP and its assumptions and concluded that the need is driven primarily by the expiration of PPAs and retirement of the Sherco units.

Q. Is there a need for an additional energy resource to meet retail load?

No. The Company's analysis estimates the Project will generate **[Trade Secret Begins]** [redacted] **[Trade Secret Ends]** MWh/year. The Company's modeling shows it has a net long energy position on an annual basis through the remainder of the decade based upon its Preferred Plan and excluding Sherco Solar. The Company will have net generation in excess of sales on the order of **[Trade Secret Begins]** [redacted] **[Trade Secret Ends]** in the 2025 – 2030 period.

VIII. Evaluation of Project Economics

Q. Did the Company develop a forecast for of the Project's cost?

A. Yes, the Company developed a revenue requirement analysis for each of the solar fields, resulting in a combined levelized cost of **[Trade Secret Begins]** [redacted] **[Trade Secret Ends]**.

Q. Did you review the Company's cost analysis for the Project?

A. Yes, I reviewed the Company's Excel models, which includes a revenue requirement model and a levelized cost calculation.[24] The Company prepared separate models for the East and West blocks of the project and a combined analysis. The Company assumes that both blocks will qualify for the Production Tax Credit (PTC). The levelized cost is as of 2021 and assumes the West Block is on-line in 2024 and the East Block is on-line in 2025. Each block assumes **[Trade Secret Begins]** [redacted] **[Trade Secret Ends]** to connect each solar field to the Sherco substation.

Q. Did the Company develop any sensitivities around the Project cost estimate?

A. Yes, the Company's estimate, as explained in testimony, reflects current tax laws and the expected construction schedule. The Company also developed a scenario assuming changes in tax laws that would allow the Project to choose tax credits in the form of the PTC versus the ITC as well as restore the PTC to its full value, which resulted in a levelized cost of **[Trade Secret Begins]** [redacted] **[Trade Secret Ends]** \$/MWh.[25]

Q. Did the Company evaluate the cost of the Project as compared to market purchases of energy?

A. The Company's revenue requirement model did not include that analysis; however, in a separate spreadsheet model the Company compared the levelized cost of the Project with the cost of purchasing an equivalent amount of capacity and energy from MISO. Because

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[24] NSP Response to NDPSC 2-002 Trade Secret
[25] PU-21-152 NDPSC-3-006 Trade Secret.

the Project provides both energy and capacity, the Company included the cost of equivalent capacity using an assumed accredited capacity rating for the Project.

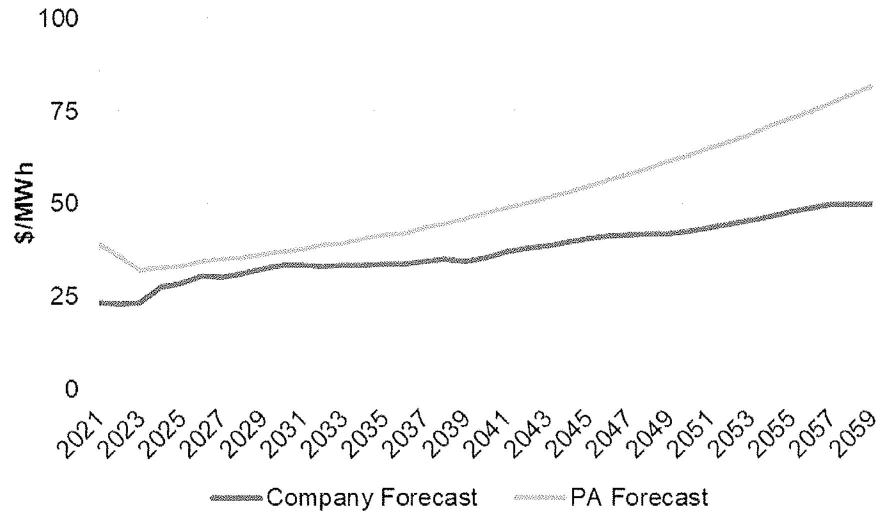
Q. How did the Company forecast the market price for electricity?

A. The Company applies a simple average of long-term implied heat rate forecasts from various proprietary market vendors to the Company's forecast of delivered natural gas prices. To derive natural gas forecast prices for Henry Hub, the Company uses the NYMEX forward curve for the first few years of their forecast period, at which point it transitions to an average of four price streams: the NYMEX forwards and three different vendor-supplied fundamental forecasts. The Henry Hub forecast is then adjusted for regional basis differentials, with the relevant natural gas hub for MISO Zone 1 being the Ventura hub in Iowa. The Company updates their energy price forecast biannually; the energy price forecast underlying the analysis put forth in the ADP is from the first half of 2021.

Q. Is the Company's forecast of the market price of electricity reasonable and how does it compare to PA Consulting's forecast?

A. I compared it to PA's forecast and determined that the Company's forecast is reasonable although appreciably lower than PA's forecast, particularly beyond 2030. *See* Figure 1. The combination of the Company's and PA's forecast constitutes a reasonable range for the long-term forecast.

Figure 1. PA Minnesota Hub On-Peak Forecast vs. NSP Forecast



Q. What accounts for the difference between the Company's and PA's forecasts?

A. The main driver for the difference between the Company's forecast and PA's is likely the underlying natural gas price forecast. PA uses a similar methodology to the Company in that we use NYMEX forwards for the near-term; however, the PA forecast then switches to PA's fundamental forecast for the remainder of the study period. The Company's forecast for power prices was made in the first half of 2021. During this time, natural gas prices were appreciably lower than they have been during the second half of 2021. PA's proprietary fundamental forecast, on the other hand, was created in late July 2021 and reflects higher underlying natural gas prices, both in the forwards market, and in the long-term fundamental forecasts. The Company's forecast is not unreasonable; however, because it relies on underlying natural gas prices that are materially lower than PA's, the overall resulting price is lower.

Q. Did the Company provide any alternatives scenarios around the cost of energy?

A. No. In a decision to select between a fossil fuel resource (the CT), market purchases, and a solar resource, the Company should have shown sensitivity of the results to alternative market price forecasts and natural gas price forecasts.

IX. Review of the Company's Proxy Pricing Proposal

Q. How did the Company evaluate the cost of the four alternative proposals for proxy pricing?

A. The Company developed a spreadsheet model for each of the four proxy costs analyzed. Each case used the same assumptions for the Equivalent Load Carrying Capability (ELCC) of the proxy CT, solar production profile, and market energy cost forecast. The four cases vary from one another based on how the Company calculated the levelized cost of proxy capacity.

Q. How did the Company account for the equivalent MISO capacity value of the Project?

A. The Company relied upon the MISO MTEP19 Report – Appendix E.[26] The Company developed two scenarios: (1) capacity value determined using a constant ELCC for solar at the currently established 50% and (2) capacity value determined by using the currently established 50% ELCC, but decreasing ELCC by two percent per year until it reaches 30% in 2033 and thereafter assuming the ELCC will remain at 30%.[27] The Company confirms recovery of cost under its proxy pricing proposal should reflect the ELCC that MISO attributes to the Project in each year.[28]

Q. Do you agree with the Company's assumption regarding the rate of decline in the ELCC?

A. I have not conducted a separate study of the likely annual ELCC of solar in MISO. After reviewing the 2021 MISO Renewable Integration Assessment;[29] however, I caution that

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[26] Appendix E: MTEP19 EGEAS Assumptions Document, p 28, Table 10.
[27] Company response to NDPSC DR 1-001_Alt A Trade Secret in Entirety.xlsx
[28] Company response to NDPSC DR 3-005.
[29] MISO's Renewable Integration Impact Assessment (RIIA) Summary Report – February 2021, Figure RA-3, p 29.

as utilities and merchant developers continue to build solar in MISO, its accredited ELCC may decline more quickly and/or end at a lower value than the Company's assumption.

Q. What would be the impact of a lower ELCC value for solar than what the Company assumes?

A. From the physical resource standpoint, NSP would have to add additional capacity resources in the future to fulfill the same capacity requirement. The estimated incremental cost of the Project compared to the savings based upon proxy pricing would increase. The Company's proposal to adjust the ELCC to actual annual ELCC means the annual cost paid by North Dakota customers will reflect the actual accredited capacity as opposed to the assumed accredited capacity in the Company's model.

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

A. Yes. Specifically, I reviewed:

- The assumptions about loads;
- The supply / demand balance (i.e., the need for new capacity);
- The forecast of net energy sales / purchases into the MISO market;
- The selection of the CT in the scenario excluding externality costs; and
- The energy margins forecast for the new CT.

Q. Is the modeled load forecast consistent with the assumptions in the Supplemental IRP?

A. While I did not get the two sales forecasts to line up, both demonstrate minimal annual load growth over the 2020 – 2034 period with the IRP having a compound annual load growth of 0.3% and the Encompass model having 0.6%. In either case, the Company is not forecasting significant load growth.

Q. Does the EnCompass modeling confirm the need for capacity identified by Mr. Chamberlin?

A. Yes.

Q. If the Company were to build the CT instead of the Project, would the Company need to secure an additional energy source to meet retail load?

A. No, the Company's resource portfolio has a long energy position; the forecast generation from its resources will exceed its retail load obligation on the order of 20% through the end of the decade and beyond. The Company is therefore not only hedging the cost of its retail load obligation, but also relying on the wholesale market prices to recover the cost of the procured resources that collectively provide generation in excess of the load obligation. In short, the energy produced by the Project is not needed to hedge the cost of the retail load obligation.

Q. Are the market energy pricing assumptions critical to the evaluation of benefits of the Project?

A. Yes, the Project's incremental levelized cost compared to the brownfield CT option is not only dependent on the tax benefits associated with constructing a solar project but is also a function of the benchmark - the market energy pricing assumptions.

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

A. Yes. When the marginal unit setting the 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.[30] 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.[31] I therefore suspect natural gas will continue to set the market price in most hours.

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[30] 2019 State of the Market Report, Midwest ISO p 4.

[31] 2019 State of the Market Analytic Report, Midwest ISO, Table A1. https://cdn.misoenergy.org/2019%20State%20of%20the%20Market%20Analytical%20Appendix455180.pdf

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

A. The NSP reference case natural gas prices is dated May 2020. While gas prices have increased dramatically since then, PA's fundamental forecast shows an easing of gas prices and the long-run PA and NSP forecasts are similar.

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

A. No, the Preferred Plan retires all coal generation by 2030 and adds large amounts of renewable energy to meet the Company's stated goal of decarbonization. The resource mix from the Encompass modeling of the Preferred plan includes large amounts of new renewable resources; however, specific resources – including the Project – are not identified for their individual contributions. *See* Table 1, below. Even if the Project is included in the resource mix, removing its 460 MW does not significantly change the overall resource mix (i.e., there would only be a 1% reduction in overall Solar PV). Regardless of whether the Project is in the resource mix, the Company is taking a long position and acquiring generation significantly in excess of its retail load obligations and will be relying on the market sales to offset the costs of its excess generation.

Table 1: Resource Mix with Sherco Solar* (GWh)

Resource	2023	2024	2025	2026	2028	2030	2032
Coal	7,079	5,733	1,988	1,747	1,952	-	-
Energy Efficiency	8,771	9,202	9,471	9,849	10,461	11,477	12,323
Gas/Oil Combined Cycle	14,705	14,130	15,282	14,128	10,660	9,361	7,432
Gas/Oil CT	414	401	195	459	629	1,058	945

Hydro	2,741	2,753	1,459	993	995	993	946
Nuclear	13,576	14,053	13,576	14,013	14,053	14,013	14,053
Biomass	648	611	367	368	232	166	166
Landfill	5	5	5	5	5	5	5
Solar PV	2,296	3,670	4,778	4,811	6,186	6,956	6,756
Wind	16,343	16,224	16,352	16,273	16,932	20,739	23,110
Total	66,578	66,783	63,473	62,645	62,104	64,767	65,737

* Table excludes system purchases

Table 2: Resource Mix (Percentages)*

Resource	2023	2024	2025	2026	2028	2030	2032
Coal	11%	9%	3%	3%	3%	0%	0%
Energy Efficiency	13%	14%	15%	16%	17%	18%	19%
Gas/Oil Combined Cycle	22%	21%	24%	23%	17%	14%	11%
Gas/Oil CT	1%	1%	0%	1%	1%	2%	1%
Hydro	4%	4%	2%	2%	2%	2%	1%
Nuclear	20%	21%	21%	22%	23%	22%	21%
Biomass	1%	1%	1%	1%	0%	0%	0%
Landfill	0%	0%	0%	0%	0%	0%	0%
Solar PV	3%	5%	8%	8%	10%	11%	10%

Public Document

Trade Secret Data Redacted

Wind	25%	24%	26%	26%	27%	32%	35%
Total	100%	100%	100%	100%	100%	100%	100%

* Table excludes system purchases

Q. Would you please summarize the results of your analysis of the proxy pricing and cost of the Project?

A. Table 3 shows a summary of the levelized cost of the Project compared to the Company's recommendation to use the MISO Gross CONE value, the Company's estimate of a brownfield CT, and my calculation of the Net CONE applied to the brownfield CT. The table shows that under tax laws the Project is not a least cost solution to securing the anticipated needed capacity. The differences between the levelized costs between using the NSP and PA long term energy forecasts highlight that there is significant uncertainty in future market prices. Within these bands, the Project is still not the least cost alternative under current tax laws. The table also highlights how potential changes in tax law could make the project look more favorable. However, approving the project would unnecessarily expose North Dakota ratepayers to market risk.

Table 3: Scenario Summary

[Trade Secret Begins]

Scenario	Levelized Cost ($/MWh)
Sherco Solar with Current Tax Laws	[redacted]
Sherco Solar with Potential Tax Law Change	[redacted]
MISO CONE	[redacted]
IRP Brownfield CT	[redacted]
IRP Brownfield with PA Energy prices	[redacted]
IRP Brownfield CT Less Energy Margins	[redacted]
IRP Brownfield CT Less PA Energy Margins	[redacted]

[Trade Secret Ends]

X. Additional Issues

Q. Are there additional issues that the Commission should consider?

A. Yes, the Commission may consider NSP's commitment to build a CT in North Dakota, whether an ADP is an appropriate docket to establish a long-term commitment for proxy pricing, and the potential for overpaying for capacity in conjunction with the treatment of the early retirement of the Sherco coal units.

Q. Is NSP's proposal consistent with the commitment to construct a CT in North Dakota?

A. My understanding is the Company committed to develop (or secure a PPA) of at least 200 MW of thermal generation in in eastern North Dakota no later than December 31, 2025.[32] The Company can still fulfill the commitment; however, I note that cost effectiveness appears to be a caveat to NSP's commitment in the settlement. The North

[32] Order Approving Settlement, March 9, 2016, First Revised Negotiated Agreement Relating to North Dakota Generation Resource Policy, PU-12-813, p. 3.

Dakota Scenario in the Supplemental IRP identifies the CT as a cost-effective resource, but this may not be the case in future scenarios when capacity is required.

Q. Is it appropriate to make a permanent decision on proxy pricing should the Commission deny an ADP for the Project but accept some form of proxy pricing?

A. No. I note that Advocacy Staff and NSP never came to agreement in the RTF proceeding. While NSP is not proposing the proxy pricing as a comprehensive approach to all future disagreements regarding the prudence of new resources, the Commission may want to avoid making a precedential decision and retain its ability to change how disputed resources are recovered in rates. This is not an instance of whether NSP is making an essentially irrevocable decision as to whether to build a CT or the Project. Rather, NSP will proceed with the Project regardless of the Commission's decision and the matter at hand is simply how ND customers should pay for its share of the resulting accredited capacity and energy. The Commission should retain the flexibility to participate in the Project to respond to any future changes that may occur (e.g., tax treatment of the Project) and ensure that savings to North Dakota are offset by any losses prior to modifying / abandoning the proxy pricing.

Q. What is your concern regarding overpaying for capacity in conjunction with proxy pricing for the Project and retirement of the Sherco coal units?

A. As the Company points out in its proxy capacity options, the Sherco coal unit could be one basis for determining the value of capacity provided by the Project. My understanding is that North Dakota's cost recovery treatment of the early retirement of the Sherco is yet to be determined and that the Company in the last rate case settlement reserved the right to request stranded cost treatment.[33] If the Commission were to approve both proxy pricing for the Project and also allow for stranded cost recovery of the Sherco Coal plant, then North Dakota customers would effectively be paying for the capacity twice.

[33] Case No. PU-20-441 Settlement Agreement, p. 4.

XI. Conclusions and Recommendations

Q. Would you please summarize your conclusions?

A. Yes.

- The Commission should deny the ADP for Sherco Solar on the basis that it would raise costs for North Dakota customers and the Company does not need additional energy to hedge its retail load obligations.
- The Commission should deny the Company's proposal for recovering the proxy cost of capacity through the FCR. The Company's proposal creates a significant precedent with regards to recovering capacity costs in the FCR or recovering the cost of disallowed Company owned resources in the FCR.
- The rate recovery for this Project, which the Company admits is imprudent under North Dakota standards, should be addressed in a future Company rate case.
- Should the Commission approve the Company's proxy pricing approach, subject to conditions and recommendations as described below, it should be on an interim basis.

Q. What is your recommendation regarding proxy pricing if the Commission decides to approve proxy pricing for the Project under the ADP?

A. I recommend the Commission direct the Company to:

- Use the brownfield CT cost as identified in the IRP and defined in the Company's response to Advocacy Staff 1-1 as the basis of the Gross CONE cost.
- The brownfield CT cost should not be updated at a later date. Updating the cost at a later date creates potential controversy about what cost the Commission is accepting. In addition, the cost presented by the Company is contemporaneous with the alternative cost of participating in the Project.
- The brownfield CT cost as defined by NSP in the fore-mentioned data response should be reduced by subtracting the energy margins I identify in my testimony and Exhibit__JAH-2,

- Annually adjust the system value of the proxy capacity based upon the MISO accredited capacity of the Project,
- The share of the MISO based accredited capacity of the Project that is assigned to ND should be based upon the capacity cost allocation factors annually updated capacity allocation factors that reflect ND's share of system capacity.
- Exclude North Dakota from any allocation of the transmission cost associated with interconnection of the Project, and
- Hold North Dakota customers harmless for any potential future intermittent renewable generation integration charges.

Q. Does this conclude your testimony?

A. Yes.

Exhibit____JAH-1
DOCKET NO. PU-21-152

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

Before the Louisiana Public Commission, Direct Testimony and Schedules of James A. Heidell in Re: Application of 1803 Electric Cooperative, Inc. For Approval of Power Purchase Agreements and For Cost Recovery, Docket No. U-35927.

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 – Heartland Divide II Wind Project, Case No. PU-20-433.

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.

JAH-2

CONFIDENTIAL-FILED AS TRADE SECRET

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Northern States Power Company
Advanced Prudence - 460MW Solar – Sherburne Cnty, MN
Application

Case No. PU-21-152

VERIFICATION

STATE OF COLORADO)
) ss.
COUNTY OF DENVER)

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 9th day of December, 2021.

JOSHUA ALEXANDER MEANS
NOTARY PUBLIC
STATE OF COLORADO
NOTARY ID 20214033887
MY COMMISSION EXPIRES AUGUST 25, 2025

Notary Public
My Commission Expires: 08/25/2025

STATE OF NORTH DAKOTA

PUBLIC SERVICE COMMISSION

Northern States Power Company
Advanced Prudence - 460MW Solar – Sherburne Cnty, MN
Application

Case No. PU-21-152

AFFIDAVIT OF SERVICE

STATE OF NORTH DAKOTA)
)ss
COUNTY OF BURLEIGH)

Anna Heinen states under oath as follows:

1. I swear and affirm upon penalty of perjury that the statements made in this affidavit are true and correct.

2. I am of legal age and on the 17th day of December, 2021, I served a true and correct copy of the attached **Direct Testimony of James Heidell (Public Version); Exhibit JAH-1; Exhibit JAH-2 (Public Version); and Verification** upon the following:

VIA EMAIL & US MAIL
Timothy Dawson
Administrative Law Judge
2911 N 14th Street- Suite 303
Bismarck, ND 58503

tjdawson@nd.gov

VIA EMAIL & US MAIL
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VIA EMAIL & HAND-DELIVERY
John Schuh
General Counsel
Public Service Commission
600 East Boulevard, Dept. 408
Bismarck, ND 58505-0480

jschuh@nd.gov

Anna Heinen

Subscribed and sworn before me this 17th day of December, 2021.

TIFFANY KNOPIK
Notary Public
State of North Dakota
My Commission Expires June 29, 2022

Tiffany Knopik

Notary Public
Burleigh County, North Dakota