



Public Service Commission

State of North Dakota

COMMISSIONERS

Brian Kroshus
Julie Fedorchak
Randy Christmann

600 East Boulevard, Dept. 408
Bismarck, North Dakota 58505-0480
Web: www.psc.nd.gov
E-mail: ndpsc@nd.gov
Phone: 701-328-2400
ND Toll Free: 1-877-245-6685
Fax: 701-328-2410
TDD: 800-366-6888 or 711

November 22, 2019

Matt Mooren
PA Consulting Group
1700 Lincoln Street, Suite 3550
Denver, CO 80203

Re: Case No. PU-19-306
Montana-Dakota Utilities Co.
Advance Prudence – Heskett 4
Application

Case No. PU-19-307
Montana-Dakota Utilities Co.
88 MW Turbine – Heskett 4
Public Convenience & Necessity

Case No. PU-19-317
Montana-Dakota Utilities Co.
Deferred Accounting – Lewis & Clark Heskett 1 & 2
Application

Dear Mr. Mooren:

At its regular meeting on November 21, 2019, the North Dakota Public Service Commission approved a motion to execute a contract with PA Consulting Group, Inc. to provide consulting services in the above referenced cases.

A copy of the Commission motion and contract are enclosed.

Best Regards,

Patrick Fahn, Director
Public Utilities Division

Enclosures

- 7 PU-19-317 Filed 11/22/2019 Pages: 122
Letter enclosing Commission Motion and executed Contract
- 12 PU-19-307 Filed 11/22/2019 Pages: 122
Letter enclosing Commission Motion and executed Contract
- 10 PU-19-306 Filed 11/22/2019 Pages: 122
Letter enclosing Commission Motion and executed Contract

APPROVED

21 Nov. 2019



**STATE OF NORTH DAKOTA
PUBLIC SERVICE COMMISSION**

**Montana-Dakota Utilities Co.
Advance Prudence – Heskett 4
Application**

Case No. PU-19-306

**Montana-Dakota Utilities Co.
88 MW Turbine – Heskett 4
Public Convenience & Necessity**

Case No. PU-19-307

**Montana-Dakota Utilities Co.
Deferred Accounting – Lewis&Clark 1 Heskett 1 & 2
Application**

Case No. PU-19-317

MOTION

November 21, 2019

I move the Commission execute a contract with PA Consulting Group, Inc. for consulting services in Montana-Dakota Utilities Co., Advance Prudence – Heskett 4, Application, Case No. PU-19-306, in Montana-Dakota Utilities Co., 88 MW Turbine – Heskett 4, Public Convenience & Necessity, Case No. PU-19-307, and in Montana-Dakota Utilities Co., Deferred Accounting – Lewis&Clark 1 Heskett 1 & 2, Application, Case No. PU-19-317.

PJF

5 **PU-19-317** Filed: 11/21/2019 Pages: 1
Commission Motion to execute contract

Public Service Commission

10 **PU-19-307** Filed: 11/21/2019 Pages: 1
Commission Motion to execute contract

Public Service Commission

8 **PU-19-306** Filed: 11/21/2019 Pages: 1
Commission Motion to execute contract

Public Service Commission

CONTRACT NUMBER PU-825-19

Administrator:	State of North Dakota Public Service Commission State Capitol - 12th Floor Bismarck, ND 58505-0480 (701) 328-2400
Date: November 21, 2019	Case No. PU-19-306, PU-19-307 & PU-19-317

Contractor PA Consulting Group, Inc.		
Name		
1700 Lincoln St, Suite 3550	Denver, CO 80203	303-589-0200
Address	City/State/Zip	Phone
Matt Mooren		PA Management Team
Typed Name	Title	

Agreement Information	
Contract No.:	<u>PU-825-19</u>
Start Date:	<u>November 21, 2019</u>
End Date:	<u>December 31, 2020</u>
Case No.	<u>PU-19-306, 307 &317</u>
Type of Contract:	<input checked="" type="checkbox"/> Fixed Price <input type="checkbox"/> Cost Reimb. <input type="checkbox"/> Unit Price <input type="checkbox"/> Other

Budget Information	
Cost Center:	<u>7300</u>
Services:	<u>\$147,755</u>
Expenses:	<u>Not applicable</u>
Type of Contractor:	<input type="checkbox"/> Individual <input checked="" type="checkbox"/> Corporation <input type="checkbox"/> Partnership <input type="checkbox"/> Public Agency <input type="checkbox"/> Nonprofit Organization <input type="checkbox"/> Other

This Contract is entered into between the State of North Dakota acting through the Public Service Commission (STATE) and PA Consulting Group, Inc. This contract consists of this sheet, general provisions and specific provisions.

PURCHASE OF SERVICE CONTRACT

The parties to this contract are the State of North Dakota, acting through its North Dakota Public Service Commission, Public Utilities Division (STATE) and PA Consulting Group, 1700 Lincoln Street, Suite 3550, Denver, CO 80203 (CONTRACTOR).

1. SCOPE OF WORK

CONTRACTOR, in exchange for the compensation paid by STATE under this Contract, agrees to provide the services enumerated below. CONTRACTOR shall be registered with the North Dakota Secretary of State and the North Dakota State Procurement Office prior to Contract execution.

CONTRACTOR agrees to perform services outlined in Section 3.01 per the schedule outlined in Section 3.05 of RFP number 408.19.09.010 and CONTRACTOR's October 23, 2019 response to RFP number 408.19.09.010 (the "CONTRACTOR's Proposal"). The written proposal provided by CONTRACTOR is attached to and incorporated into this agreement.

2. COMPENSATION

Contractual Amount

STATE shall pay for the accepted services provided by CONTRACTOR under this Contract an amount not to exceed \$147,755. For the purposes of clarity, the services included in the contractual amount are Tasks 1 – 8 in the CONTRACTOR'S Proposal

The Contractual Amount is firm for the duration of the Contract and constitutes the entire compensation due CONTRACTOR for performance of its obligations under this Contract, unless amended, regardless of this difficulty, materials or equipment required, including fees, licenses, overhead, profit and all other direct and indirect costs incurred by CONTRACTOR, except as provided by an amendment to this Contract.

The STATE will make payments based on a monthly payment schedule. Each billing must consist of an invoice listing hours worked at the contract rate, the staff person completing the work, and include a progress report. No payment will be made until the Project Manager has reviewed the progress report and approved the invoice.

Victor Schock – Project Manager
Public Utility Analyst – North Dakota Public Service Commission
600 E Boulevard Ave, Dept 408
Bismarck, ND 58505-0480
vschock@nd.gov
701-328-3397

The STATE will not make any advance payments before performance by the CONTRACTOR under this contract.

Payment

1. Payment made in accordance with this Compensation section constitutes payment in full for the services and work performed and the deliverables and work(s) provided under this Contract and CONTRACTOR will not receive any additional compensation hereunder.
2. STATE will make every attempt to make payment under this Contract within thirty (30) calendar days after receipt of an approved invoice.
3. Payment of an invoice by STATE will not prejudice STATE's right to object to or question that or any other invoice or matter in relation to this contract. CONTRACTOR's invoice will be subject to reduction for amounts included in any invoice or payment made which are determined by STATE, on the basis of audits conducted in accordance with the terms of this Contract, not to constitute allowable costs. At STATE's sole discretion, all payments shall be subject to reduction for amounts equal to prior overpayments to CONTRACTOR.
4. For any amounts that are or will become due and payable to STATE by CONTRACTOR, STATE reserves the right to deduct the amount owed from the payments that are or will become due and payable to CONTRACTOR under this Contract.

Travel

CONTRACTOR acknowledges travel costs are included in the Contractual Amount and may include travel costs in the monthly invoices submitted to STATE.

Prepayment

STATE will not make any advance payments before full performance by CONTRACTOR under this Contract.

Payment of Taxes by STATE

STATE is not responsible for and will not pay local, state, or federal taxes. STATE sales tax exemption number is E-2001, and certificates will be furnished upon request by the purchasing agency.

Taxpayer ID

CONTRACTOR'S federal employer ID number is: 22-2287449

3. TERM OF CONTRACT

This Contract begins on the date the last party has fully executed the Contract, and ends on December 31, 2020.

No Automatic Renewal

This Contract will not automatically renew.

Extension Option

STATE reserves the right to extend the Contract up to three times for an additional period of time not to exceed 12 months per extension.

Renewal Option

STATE may renew this Contract upon satisfactory completion of the initial Contract term. STATE reserves the right to execute up to three options to renew this Contract under the same terms and conditions for a period of twelve months each.

4. TIME IS OF THE ESSENCE

CONTRACTOR hereby acknowledges that time is of the essence for performance under this Contract unless otherwise agreed to in writing by the parties.

5. TERMINATION OF CONTRACT

Termination by Mutual Agreement

This Contract may be terminated by mutual consent of both parties, executed in writing.

Termination without Cause

STATE may terminate this Contract in whole or in part when it has determined that continuing the Contract is no longer necessary or would not produce beneficial results commensurate with the further expenditure of public funds.

Termination for Lack of Funding or Authority

STATE by written notice to CONTRACTOR, may terminate the whole or any part of this Contract under any of the following conditions:

- 1) If funding from federal, state, or other sources is not obtained and continued at levels sufficient to allow for purchase of the services or supplies in the indicated quantities or term.
- 2) If federal or state laws or rules are modified or interpreted in a way that the services are no longer allowable or appropriate for purchase under this Contract or are no longer eligible for the funding proposed for payments authorized by this Contract.
- 3) If any license, permit, or certificate required by law or rule, or by the terms of this Contract, is for any reason denied, revoked, suspended, or not renewed.

Termination of this Contract under this subsection is without prejudice to any obligations or liabilities of either party already accrued prior to termination.

Termination for Cause

STATE may terminate this Contract effective upon delivery of written notice to CONTRACTOR, or any later date stated in the notice:

- 1) If CONTRACTOR fails to provide services required by this Contract within the time specified or any extension agreed to by STATE; or
- 2) If CONTRACTOR fails to perform any of the other provisions of this Contract, or so fails to pursue the work as to endanger performance of this Contract in accordance with its terms.

The rights and remedies of STATE provided in this subsection are not exclusive and are in addition to any other rights and remedies provided by law or under this Contract.

6. FORCE MAJEURE

Neither party shall be held responsible for delay or default caused by fire, flood, riot, acts of God or war if the event is beyond the party's reasonable control and the affected party gives notice to the other party immediately upon occurrence of the event causing the delay or default or that is reasonably expected to cause a delay or default.

7. INDEMNITY

CONTRACTOR agrees to defend, indemnify, and hold harmless the state of North Dakota, its agencies, officers and employees (STATE), from and against claims based on the vicarious liability of the STATE or its agents, but not against claims based on the STATE's contributory negligence, comparative and/or contributory negligence or fault, sole negligence, or intentional misconduct. The legal defense provided by CONTRACTOR to the STATE under this provision shall be free of any conflicts of interest, even if retention of separate legal counsel for the STATE is necessary. An attorney appointed to represent the STATE shall first qualify as and be appointed by the North Dakota Attorney General as a Special Assistant Attorney General as required under North Dakota Century Code section 54-12-08. CONTRACTOR also agrees to defend, indemnify, and hold the STATE harmless for all costs, expenses, and attorneys' fees incurred if the STATE prevails in an action against CONTRACTOR in establishing and litigating the indemnification coverage provided herein. This obligation continues after the termination of this agreement.

8. INSURANCE

CONTRACTOR shall secure and keep in force during the term of this agreement and CONTRACTOR shall require from all subcontractors, prior to commencement of an agreement between Contractor and the subcontractor, to secure and keep in force during the term of this agreement, from insurance companies, government self-insurance pools or government self-retention funds, authorized to do business in North Dakota, the following insurance coverages:

- 1) Commercial general liability, including premises or operations, Contractual, and products or completed operations coverages (if applicable), with minimum liability limits of \$250,000 per person and \$1,000,000 per occurrence.
- 2) Automobile liability, including Owned (if any), Hired, and Non-Owned automobiles, with minimum liability limits of \$250,000 per person and \$1,000,000 per occurrence.
- 3) Workers compensation coverage meeting all statutory requirements. The policy must provide coverage for all states of operation that apply to the performance of this Contract.

- 4) Employer's liability or "stop gap" insurance of not less than \$1,000,000 as an endorsement on the workers compensation or commercial general liability insurance.

The insurance coverages listed above must meet the following additional requirements:

- 1) Any deductible or self-insured retention amount or other similar obligation under the policies is the sole responsibility of CONTRACTOR. The amount of any deductible or self-retention is subject to approval by the STATE.
- 2) This insurance may be in policy or policies of insurance, primary and excess, including the so-called umbrella or catastrophe form and must be placed with insurers rated "A-" or better by A.M. Best Company, Inc., provided any excess policy follows form for coverage. Less than an "A-" rating must be approved by the STATE. The policies must be in form and terms approved by the STATE.
- 3) The duty to defend, indemnify, and hold harmless the STATE under this agreement is not limited by the insurance required in this agreement.
- 4) The State of North Dakota and its agencies, officers, and employees (STATE) shall be endorsed on the commercial general liability policy, including any excess policies (to the extent applicable), as additional insured. The STATE shall have all the benefits, rights and coverages of an additional insured under these policies that may not be limited to the minimum limits of insurance required by this agreement or by the Contractual indemnity obligations of CONTRACTOR.
- 5) The insurance required in this agreement, through a policy or endorsement, must include:
 - a) "Waiver of Subrogation" waiving any right to recovery the insurance company may have against the STATE;
 - b) a provision that CONTRACTOR'S insurance coverage is primary (i.e. pay first) as respects any insurance, self-insurance or self-retention maintained by the STATE and that any insurance, self-insurance or self-retention maintained by the STATE is in excess of the CONTRACTOR'S insurance and does not contribute with it;
 - c) cross liability/severability of interest for all policies and endorsements;
 - d) The legal defense provided to the STATE under the policy and any endorsements must be free of any conflicts of interest, even if retention of separate legal counsel for the STATE is necessary;
 - e) The insolvency or bankruptcy of the insured CONTRACTOR does not release the insurer from payment under the policy, even when such insolvency or bankruptcy prevents the insured CONTRACTOR from meeting the retention limit under the policy.
- 6) CONTRACTOR shall furnish a certificate of insurance to the undersigned STATE representative prior to commencement of this agreement. All endorsements must be provided as soon as practicable.

- 7) Failure to provide insurance as required in this agreement is a material breach of Contract entitling the STATE to terminate this agreement immediately.
- 8) CONTRACTOR shall provide at least 30 day notice of any cancellation or material change to these policies or endorsements. Contractor shall provide on an ongoing basis, current certificates of insurance during the term of the contract. A renewal certificate will be provided 10 days prior to coverage expiration. An updated, current certificate of insurance shall be provided in the event of any change to a policy.

9. WORKS FOR HIRE

CONTRACTOR acknowledges that all work(s) under this Contract is "work(s) for hire" within the meaning of the United States Copyright Act (Title 17 United States Code) and hereby assigns to STATE all rights and interests CONTRACTOR may have in the work(s) it prepares under this Contract, including any right to derivative use of the work(s). All software and related materials developed by CONTRACTOR in performance of this Contract for STATE shall be the sole property of STATE, and CONTRACTOR hereby assigns and transfers all its right, title, and interest therein to STATE. CONTRACTOR shall execute all necessary documents to enable STATE to protect STATE's intellectual property rights under this section. Notwithstanding, CONTRACTOR shall remain the owner of all intellectual property rights it possessed prior to this Agreement, as well as all modifications or adaptations made to that intellectual property during the Agreement ("CONTRACTOR Pre-Existing IP"). If any CONTRACTOR Pre-Existing IP is included as a deliverable hereunder, CONTRACTOR hereby grants the STATE a nonexclusive, royalty-free, world-wide right to use that Background IP as part of the deliverable with which it was included for the ordinary business purposes of the STATE.

10. WORK PRODUCT

All work product, equipment or materials created or purchased under this Contract belong to STATE and must be delivered to STATE at STATE'S request upon termination of this Contract.

11. NOTICE

All notices or other communications required under this Contract must be given by registered or certified mail and are complete on the date mailed when addressed to the parties at the following addresses:

PA Consulting Group
1700 Lincoln Street, Suite 3550
Denver, CO 80203

North Dakota Public Service Commission
600 East Boulevard Ave, Dept. 408
Bismarck, ND 58505-0480

Notice provided under this provision does not meet the notice requirements for monetary claims against the STATE found at North Dakota Century Code section 32-12.2-04.

12. CONFIDENTIALITY

CONTRACTOR shall not use or disclose any information it receives from STATE under this Contract that STATE has previously identified as confidential or exempt from mandatory public disclosure except as necessary to carry out the purposes of this Contract or as authorized in advance by STATE. STATE shall not disclose any information it receives from CONTRACTOR that CONTRACTOR has previously identified as confidential and that STATE determines in its sole discretion is protected from mandatory public disclosure under a specific exception to the North Dakota open records law, North Dakota Century Code chapter 44-04. The duty of STATE and CONTRACTOR to maintain confidentiality of information under this section continues beyond the term of this Contract.

13. COMPLIANCE WITH PUBLIC RECORDS LAW

CONTRACTOR understands that, except for disclosures prohibited in this Contract, STATE shall disclose to the public upon request any records it receives from CONTRACTOR. CONTRACTOR further understands that any records that are obtained or generated by CONTRACTOR under this Contract, except for records that are confidential under this Contract, may, under certain circumstances, be open to the public upon request under the North Dakota open records law. CONTRACTOR agrees to contact STATE immediately upon receiving a request for information under the open records law and to comply with STATE'S instructions on how to respond to the request.

14. INDEPENDENT ENTITY

CONTRACTOR is an independent entity under this Contract and is not a STATE employee for any purpose, including the application of the Social Security Act, the Fair Labor Standards Act, the Federal Insurance Contribution Act, the North Dakota Unemployment Compensation Law and the North Dakota Workforce Safety and Insurance Act. CONTRACTOR retains sole and absolute discretion in the manner and means of carrying out CONTRACTOR'S activities and responsibilities under this Contract, except to the extent specified in this Contract.

15. ASSIGNMENT AND SUBCONTRACTS

CONTRACTOR may not assign or otherwise transfer or delegate any right or duty without STATE'S express written consent. However, CONTRACTOR may enter into subcontracts provided that any subcontract acknowledges the binding nature of this Contract and incorporates this Contract, including any attachments. CONTRACTOR is solely responsible for the performance of any subcontractor. CONTRACTOR does not have authority to Contract for or incur obligations on behalf of STATE.

16. SPOILIATION – NOTICE OF POTENTIAL CLAIMS

CONTRACTOR shall promptly notify STATE of all potential claims that arise or result from this Contract. CONTRACTOR shall also take all reasonable steps to preserve all physical evidence and information that may be relevant to the circumstances

surrounding a potential claim, while maintaining public safety, and grants to STATE the opportunity to review and inspect the evidence, including the scene of an accident.

17. MERGER AND MODIFICATION

This Contract, including the following documents, constitutes the entire agreement between the parties. There are no understandings, agreements, or representations, oral or written, not specified within this Contract. This Contract may not be modified, supplemented or amended, in any manner, except by written agreement signed by both parties.

Notwithstanding anything herein to the contrary, in the event of any inconsistency or conflict among the documents making up this Contract, the documents shall control in this order of precedence:

- a. The terms of this Contract as may be amended;
- b. STATE RFP number 408.19.09.010
- c. CONTRACTOR's written negotiated proposal dated October 23, 2019.
- d. All terms and conditions contained in any end user agreements (e.g. automated click-throughs, shrink wrap, or bonus wrap) are specifically excluded and null and void, and may not alter the terms of this Contract.

18. SEVERABILITY

If any term of this Contract is declared by a court having jurisdiction to be illegal or unenforceable, the validity of the remaining terms is unaffected, and, if possible, the rights and obligations of the parties are to be construed and enforced as if the Contract did not contain that term.

19. APPLICABLE LAW AND VENUE

This Contract is governed by and construed in accordance with the laws of the STATE. Any action to enforce this Contract must be adjudicated exclusively in the State District Court of Burleigh County, North Dakota. Each party consents to the exclusive jurisdiction of such court and waives any claim of lack of jurisdiction or forum non conveniens.

20. ALTERNATIVE DISPUTE RESOLUTION – JURY TRIAL

STATE does not agree to any form of binding arbitration, mediation, or other forms of mandatory alternative dispute resolution. The parties have the right to enforce their rights and remedies in judicial proceedings. STATE does not waive any right to a jury trial.

ATTORNEY FEES

In the event a lawsuit is instituted by STATE to obtain performance due under this Contract, and STATE is the prevailing party, CONTRACTOR shall, except when prohibited by North Dakota Century Code section 28-26-04, pay STATE'S reasonable attorney fees and costs in connection with the lawsuit.

21. NONDISCRIMINATION AND COMPLIANCE WITH LAWS

CONTRACTOR agrees to comply with all laws, rules, and policies, including those relating to nondiscrimination, accessibility and civil rights. CONTRACTOR agrees to timely file all required reports, make required payroll deductions, and timely pay all taxes and premiums owed, including sales and use taxes and unemployment compensation and workers' compensation premiums. CONTRACTOR shall have and keep current at all times during the term of this Contract all licenses and permits required by law.

22. STATE AUDIT

All records, regardless of physical form, and the accounting practices and procedures of CONTRACTOR relevant to this Contract are subject to examination by the North Dakota State Auditor, the Auditor's designee, or Federal auditors. CONTRACTOR shall maintain all such records for at least three years following completion of this Contract and be able to provide them at any reasonable time. STATE, State Auditor, or Auditor's designee shall provide reasonable notice.

23. EFFECTIVENESS OF CONTRACT

This Contract is not effective until fully executed by both parties.

CONTRACTOR

PA Consulting Group, Inc.

By: 

Title: Matt Mooren, Member of PA's Management Group

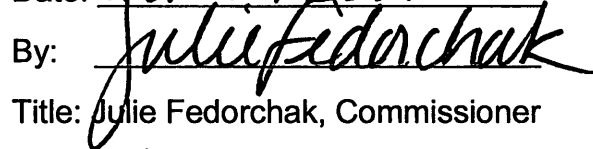
Date: November 18, 2019

STATE OF NORTH DAKOTA

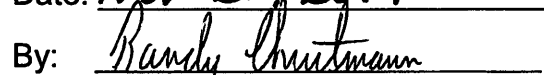
Acting through its North Dakota Public Service Commission

By: 

Title: Brian Kroshus, Chairman

Date: Nov 21, 2019
By: 

Title: Julie Fedorchak, Commissioner

Date: Nov 21, 2019
By: 

Title: Randy Christmann, Commissioner

Date: Nov 21, 2019



NORTH DAKOTA PUBLIC SERVICE COMMISSION - RFP NO. 408.19.09.010

MONTANA-DAKOTA UTILITIES CO ADVANCE
DETERMINATION OF PRUDENCE, CERTIFICATE OF
PUBLIC CONVENIENCE AND NECESSITY - HESKETT 4

October 23, 2019

Bringing Ingenuity to Life
paconsulting.com

Denver Office
PA Consulting Group Inc.
Suite 3550
1700 Lincoln Street
Denver
CO 80203
USA
+1 720 566 9920
paconsulting.com

Prepared by: PA Consulting Group, Inc.
Reference: P047958
Version: Final

Executive Summary

The North Dakota Public Service Commission (NDPSC or Commission) is evaluating Montana-Dakota Utilities Co.'s (MDU or Company) application for an Advance Determination of Prudence (ADP) and Certificate of Public Convenience and Necessity (CPCN) for its Heskett 4 simple cycle combustion turbine (CT), and application for deferred accounting for the retirement of three coal units which would create the need for the CT. The Commission is soliciting proposals to conduct a thorough analysis of the application, provide written and oral testimony at the Commission's technical hearing and assist in the preparation of pre- and post-hearing documents or possibly documents for the purposes of moving to dismiss the application.

The application relates to MDU constructing, owning and operating Heskett 4, an 88 MW CT and the retirement of three coal-fired units. Heskett 4 will be located on Company owned property adjacent to MDU's Heskett 3, an 88 MW CT near Mandan, North Dakota. Due to its location in North Dakota, there is a rebuttable presumption of prudence for Heskett 4. The application for deferred accounting treatment relates to the proposed retirement of three coal-fired units – Lewis & Clark 1, Heskett 1, and Heskett 2. Lewis & Clark 1 is a 50 MW generating station located in Sidney, Montana. Heskett 1 and 2 are 40 MW and 75 MW units. MDU is proposing to retire Lewis & Clark 1 in March 2021, and the Heskett units in March 2022.

The NDPSC will evaluate whether Heskett 4 meets the standard for the ADP and CPCN. MDU's Integrated Resource Plan (IRP) filed with the Commission on July 1, 2019 (Case No. PU-19-221) details the need for the addition of Heskett 4 beginning in 2020. MDU's application in support of the ADP references the recently completed analysis in the IRP and highlights MDU's conclusion that the self-build option on an existing site provides a significant cost advantage over a greenfield site. MDU's conclusion is that Heskett 4 presents the most economical solution to meet its customers' supply needs. MDU also contends that the proposed retirements represent unusual and non-recurring expenses, and as such should be amortized under deferred accounting treatment.

PA does not have preconceived conclusions regarding whether Heskett 4 should be approved, and whether deferred accounting is the appropriate treatment for the retirement of the three coal-fired units. However, we have identified a number of issues and considerations that should be addressed in the review of MDU's public applications. These issues and considerations include the following:

- The econometric load forecast presented in the IRP should be reviewed to verify that there is a need for a new resource;
- The IRP should be evaluated to affirm or reject the conclusion that the most economical option to meet peak and energy requirements is the retirement of three coal plants and acquiring a new generation resource;
- If a new generation resource is the most appropriate solution, it should be verified that a CT is the preferred option;
- If the CT is the preferred option, it should be verified that the self-build option is the least cost solution;
- Assuming that the self-build option is preferred, the ADP evaluation should consider whether there are reasonable cost controls associated with this solution; and
- If retirement of the three coal units is the least cost solution, the ADP evaluation should consider whether the proposed deferred accounting treatment is reasonable.

To address these issues, we propose an analytic review and associated testimony that includes:

- A review of the load forecast and power supply portfolio to evaluate the proposed retirement decision and the associated need for additional resources;
- A review of the MDU system modeling used to support MDU's conclusions including: fuel cost assumptions, load forecast, operating cost of the coal plants, cost assumptions associated with new generation resources, and Midcontinent Independent System Operator (MISO) wholesale electricity prices;
- Evaluation of the planning scenarios used by MDU to opine on whether the scenarios appropriately reflect the range of outcomes given uncertainties regarding future technology costs, supply/demand conditions, fuel costs, infrastructure changes, and future regulations;
- Evaluation of MDU's savings estimates associated with the self-build option on the Heskett site; and
- A critical evaluation of MDU's proposed deferred accounting treatment, including the nature of costs subject to deferral, appropriate amortization periods, recovery/expenditure reconciliation practices, cost allocation fairness, and alignment with the North Dakota Administrative Code and regulatory precedents.

PA is highly qualified to assist the Commission Advocacy Staff in evaluating MDU's request for the ADP, CPCN, and deferred accounting treatment. We understand the background behind the MDU application and the concerns of Advocacy Staff. We understand the fundamentals of the MISO market and have developed multiple MISO market forecasts including projecting asset dispatch. We frequently analyze energy policies and their influence on generation investment, planning prudence, and necessity. We have significant expertise in advising on utility finance and accounting issues and have worked previously with the Commission on applications for deferred accounting treatment. We have extensive experience testifying at utility regulatory hearings, including testimony before the Commission, and we have an extensive track record of working collaboratively with our clients.

Our proposed assignment team is composed of individuals who have worked closely with NDPSC Advocacy Staff on a number of recent ADP, CPCN, and deferred accounting treatment applications, and the team has reserved their time for this effort should PA be awarded this important assignment.

Contents

Executive Summary	3	
1	Introduction	6
1.1	Submitting Firm	6
1.2	Introduction to PA	6
1.3	Our Global Energy & Utilities Practice	7
1.4	Why PA Consulting Group?	8
1.5	Conflicts of interest and our ability to serve	9
2	Our Understanding and Approach for the ADP Evaluation	10
2.1	Key Issues	10
2.2	Approach to Analyzing the Key Issues	11
3	Our Proposed Work Plan	13
3.1	Proposed Project Schedule	16
4	Experience and Qualifications	18
4.1	Our Qualifications	18
4.2	Client References	20
5	Project Team	21
5.1	Project Team	21
5.2	Team bios	22
6	Cost Proposal	24
7	Required Enclosures	25
7.1	Purchase Service Agreement Deviations and Exceptions	25



1 Introduction

1.1 Submitting Firm

PA Consulting Group, Inc. (PA) is pleased to submit this proposal to the North Dakota Public Service Commission (NDPSC or the Commission). Our firm address, contact details, and primary contact follow. Matt Mooren, a Member of PA's Management Group, is authorized to bind PA to this proposal.

Firm Name: PA Consulting Group, Inc.
Primary Contact: Matt Mooren
720-566-9944
Matt.Mooren@PAConsulting.com

Mailing Address: 1700 Lincoln Street
Suite 3550
Denver, CO 80203

Matt Mooren
Member of PA's Management Group

1.2 Introduction to PA

PA is a leading global management, systems, technology and strategy consulting firm. Established 75 years ago, we operate from 24 offices in the US, Europe, Gulf and Asia Pacific. Our clients include many of the largest utilities and government entities in the US who draw upon on the insights and implementation knowledge of PA's over 2,800 consultants.

PA combines in-depth industry knowledge with market-leading capability in order to help tackle challenges and achieve our clients' goals.

We have the practical experience to quickly get to grips with your business challenges, and the confidence to challenge conventional thinking to develop a response.

Our people are committed to working alongside your team to tackle challenges jointly, to deliver real, lasting impact. We leave your business with enhanced skills, tools and knowledge, better equipped to deliver the next set of initiatives.



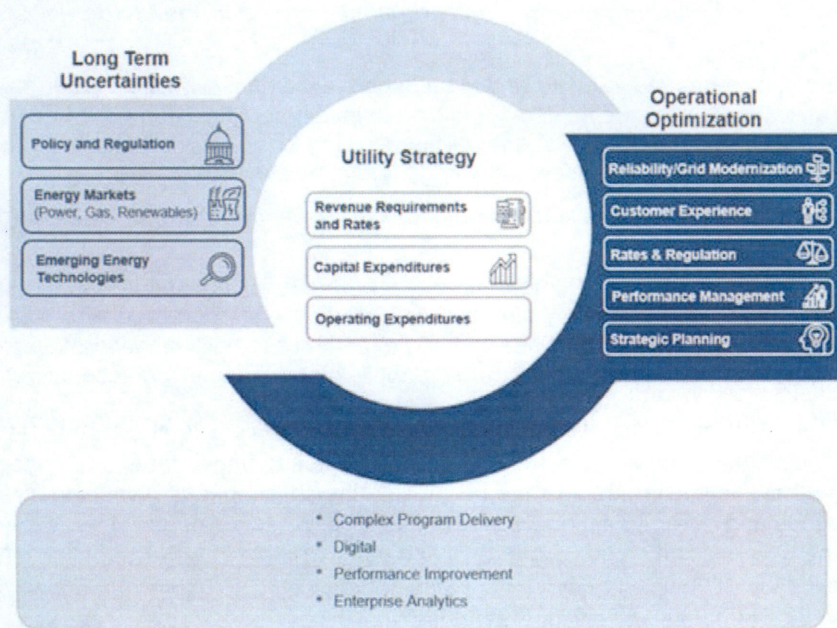
Eight Sectors:

- Energy and utilities
- Financial services
- Life sciences
- Consumer products and manufacturing
- Healthcare
- Defence
- Public sector
- Transport and logistics

1.3 Our Global Energy & Utilities Practice

PA brings deep energy industry expertise, with a focus on energy policy, regulation of markets and utilities, wholesale market structures and fundamentals, utility strategy, and utility operations. Whether we work for regulatory bodies, utilities and other load-serving entities, infrastructure investors, or other energy industry players, we put smart, experienced, professionals on the ground to work with your team to evaluate organizational, regulatory and financial opportunities and challenges. With over 300 consultants throughout the firm specifically supporting the energy and utility sector, our expertise enables PA to provide unparalleled assistance across the utility value chain. In recent years PA consultants have advised on a variety of utility rate and regulatory matters, and our analysis and recommendations are developed based on documented facts to provide a comprehensive, independent view of high-profile issues.

PA's Utility Strategy, Operations, and Energy Markets Advisory



1.4 Why PA Consulting Group?

Our proposed team of industry-leading experts will enable the Commission's team to draw upon expertise and best practices from both the US and internationally. We understand the issues facing both the NDPSC internally as well as the regulatory environment in North Dakota, having assisted the Commission with similar regulatory filings related to Advanced Determination of Prudency (ADP) and Certificate of Public Convenience and Necessity (CPCN) determinations, dispatch projections of renewable assets into the Midcontinent Independent System Operator (MISO) market, independent evaluator services, and other areas.

This combination of experience provides PA a unique understanding and viewpoint on the needs of the NDPSC, MDU's customers, and other stakeholders.

We understand the background behind MDU's Application for an ADP and a CPCN, and the concerns of the NDPSC

In recent years, PA has provided consulting services for the NDPSC related to ADP and CPCN determinations, deferred accounting treatments, and developed testimony on behalf of the Advocacy Staff in multiple dockets:

- Otter Tail Power's Merricourt and Astoria ADP and CPCN Applications (Case No. PU-17-140, PU-17-141, & PU-17-143)
- Northern States Power's (NSP) Biomass Purchase ADP Application and deferred accounting request (Case No. PU-17-270)
- NSP's Dakota Range III ADP Application (Case No. PU-18-430)
- NSP's Dakota Range Wind ADP Application (Case No. PU-17-372)
- NSP's 1,550 MW of Wind ADP Application (Case No. PU-17-120)
- NSP's RTF Application (Docket No. E-002/M-16-223)

We have extensive experience modelling the MISO market and projecting the impacts of generation retirements and additions

PA has a robust, well-developed, and industry-tested fundamental modeling process, including its proprietary stochastic dispatch optimization, capacity compensation, environmental, renewable, and valuation models along with the use of production cost, transmission, and natural gas models that are operated by PA's subject matter experts and populated with PA proprietary data. Since 2011, we have supported over 300 electric infrastructure purchases, sales, financings, or appraisals in every region in the contiguous United States, including over 400 GW of power generation. In MISO specifically, we have projected asset dispatch and operations to support the transactions or financing of over 25 GW of power generation assets, including coal, natural gas-fired generation, hydroelectric, wind, biomass, and solar as well as evaluating natural gas pipeline projects and HVDC transmission development projects.

We have extensive experience regarding energy policy analysis and its influence on generation investment and planning prudency

Our proposed team includes experienced industry and legal experts who help clients consider the full range of benefits, opportunities, and risks associated with electric sector policy and investment decisions. PA has provided analytical support for trade associations, energy think tanks, and utilities seeking to better understand market environments and influence the design of key policies and regulations affecting the electricity sector.

We understand utility accounting and have extensive experience evaluating applications for deferred accounting treatment

PA regularly works with utilities to analyze and determine the appropriate accounting treatment for assets and contracts, completing specialized technical accounting and cost studies to support regulatory accounting and compliance activities. Our industry experts have wide-ranging experience in utility finance and accounting and have provided expert testimony before the Commission regarding applications for deferred accounting treatment.

We have extensive utility regulatory experience including experience testifying in regulatory hearings

PA is routinely engaged on a broad range of electric regulatory issues and understands the principles of regulation, the challenges that regulators have in implementing state policy, and the challenges of balancing a number of competing objectives. For this prudency and deferred accounting evaluation, we will focus on collaborating with the Commission and staff to first inform the Commission on the economics and other aspects of MDU's application, and then support the Commission's preferred direction through direct testimony by PA expert witnesses as well as providing evidence and demonstratives to buttress the Commission's arguments.

We have an extensive track record of collaboration

In addition to our significant analytical and regulatory advisory experience, PA takes pride in our history of collaboration with our clients. We readily acknowledge that in virtually all cases, our client knows exponentially more than we do about their particular situation. We work hard at closely communicating and collaborating with our clients throughout an entire engagement and making sure we are delivering exactly what is needed. It is rare that an engagement unfolds exactly as expected by either PA or our clients, and we strive to be flexible with regard to both the project scope and schedule to accommodate the inevitable twists and turns which arise.

1.5 Conflicts of interest and our ability to serve

PA has reviewed the provisions of RFP Number 408.19.09.010, and if selected will comply with all the provisions of the RFP. PA has not identified any potential conflicts of interests related to this RFP and is not aware of any representation of organizations that are adverse to the NDPSC. There are no past or present civil or criminal legal investigations, or pertinent litigation and or regulatory actions that impact PA's ability to serve in the required capacity.

PA specifically notes that we have not worked directly for MDU in at least the past five years. PA will not work with MDU in the future on matters related to this proceeding. Furthermore, the core team assigned to this effort will not work on any matters for MDU or its affiliates during this engagement without the prior written approval of the NDPSC.



2 Our Understanding and Approach for the ADP Evaluation

MDU is seeking an ADP and CPCN for the construction of the 88 MW Heskett 4 simple cycle combustion turbine (CT). MDU is also seeking deferred accounting treatment associated with the proposed retirement of 165 MW of coal generation associated with three generation units. After reviewing the ADP Application and MDU's pre-filed testimony, we have identified a number of issues we believe the Commission should take into consideration regarding the ADP and we have identified an approach to address those issues.

2.1 Key Issues

PA proposes to frame our analysis around the following issues. As appropriate, we will update this after our initial discussions with Advocacy Staff.

- ***Is there a need for a new generation resource?*** MDU is seeking authorization to add 88 MW of natural gas-fired capacity to its system while retiring the coal units comprising 165 MW. The econometric load forecast presented in MDU's IRP should be reviewed to verify there is a need for the new resource. MDU presents analysis in its application forecasting a capacity deficit due to the retirement of the three coal units and estimates that this deficit will be 92 zonal resource credits (ZRC) once the units are retired. Heskett 4 will add approximately 78 ZRCs. While there is a rebuttable presumption that a resource addition located within North Dakota is prudent, the Commission should undertake a thorough review of the load forecast and scenarios presented in the IRP to determine if there is a need for Heskett 4.
- ***Is retiring the three coal units and replacing them with a new generation resource the most economical option?*** The cornerstone of MDU's analysis that Heskett 4 is needed appears to be based upon the assumption that the preferred solution is the retirement of three coal units. While MDU analyzed thirteen planning scenarios, including nine sensitivity runs, that all indicated that the proposed plan is least cost, it is important to independently review the appropriateness of the scenarios and associated assumptions.
- ***If a new generation resource is required, is a CT the preferred option?*** MDU evaluated numerous other technologies before selecting a CT for their proposed resource addition. PA will review the assumptions related to new generation alternatives and opine on whether the assumptions are reasonable. We note that the MDU application includes consideration of natural gas cost volatility and we will examine how those considerations may have impacted their conclusion regarding the preferred resource expansion plan.
- ***If the CT is the preferred option, is the self-build option the least cost solution?*** Assuming that PA's review confirms that a CT is the preferred option for a new generation resource, we recommend that the Commission consider whether the self-build option by MDU is in fact the least cost solution. MDU puts forth a number of strong arguments contending that their proposed contracting approach – Engineer, procurement support, and Construction Management (EpCM) – is the best approach and least cost solution. However, MDU

also notes that the information received from Burns & McDonnell Engineering Company regarding contracting and costs was screening-level in nature, and a more robust analysis would be required. We will review the relevant and available information and proffer our conclusions regarding whether the EpCM approach is the preferred option.

- ***If the self-build is the preferred option, are there reasonable cost controls associated with this solution?*** Because MDU does not have firm costs for the Heskett 4 project, we will consider whether it is appropriate to recommend conditions on the ADP approval so that the Commission can monitor the progress of the project and potentially create a cap on the costs approved in the ADP. Potentially the costs over the cap would be subject to future review.
- ***If retirement of the three coal units is the least cost solution, is the proposed deferred accounting treatment reasonable?*** MDU asserts that because the expenses associated with the proposed transactions represent unusual, non-recurring expenditures that were not contemplated at the time the current rates were established, and because they are sufficiently large that they could accelerate the timing of a rate case, deferred accounting treatment is appropriate. PA recommends that the specific costs be evaluated to make sure there is not double recovery. For example, some of the costs may already be recovered in rates and therefore would not be unusual or non-recurring.

2.2 Approach to Analyzing the Key Issues

Our approach to analyzing the key issues is focused around independent validation of the MDU analysis and independent economic analysis based upon PA modeling. Different modeling approaches for resource planning have their own strengths and weaknesses and hence could yield different conclusions. As such, we will supplement the MDU modeling with additional analysis using PA's hourly chronological dispatch model of the MISO market and stochastic dispatch optimization model to assess Heskett 4.

2.2.1 Review and Critique of MDU's Analysis

We will conduct a critical review of MDU's modelling assumptions as described in the Application and set forth in the July 2019 IRP. We will review MDU's EGEAS model and the input assumptions developed by MDU to evaluate their reasonableness. Our review will focus on the critical model inputs used in the different scenarios including:

- Energy and demand forecasts,
- Fuel price forecasts,
- Cost forecast for alternate generation expansion options,
- Any assumptions regarding the costs of emissions,
- Production estimates from the wind projects,
- Transmission constraints between MISO zones, and
- MISO market pricing.

In order to assess the reasonableness of MDU's assumptions we will probe into the sources relied upon, any underlying models used to create the EGEAS model inputs, third party benchmarks, and PA's databases.

2.2.2 PA's Independent Modeling

PA will leverage our most recent Base Case energy market forecast for the MISO markets in order to validate MDU's results, or potentially provide an alternative perspective Commission. Our market price forecast uses many of the same categories of inputs described above and has been leveraged in past testimony for the State of North Dakota. However, our Base Case input assumptions will reflect PA's independent view.

2.2.3 Petition for Deferred Accounting

MDU has requested authority for deferred accounting treatment of costs related to the retirement of the Lewis & Clark 1, Heskett 1 and Heskett 2 coal-fired power plants until disposition of its next general rate case. The request for deferred accounting treatment is necessitated by the Company's intended retirement of the three coal-fired units. The business decision to retire these units is based on the age of the plants, the availability of low-cost natural gas driving down prices in the MISO market, as well as rising coal costs and O&M expenses at each of the units. The evaluation of the business decision will be addressed in the previously outlined approach to review MDU's economic analysis.

The use of deferred accounting treatment as a regulatory mechanism has been a common practice in the utility industry for many years. Deferred accounting is typically used to match revenues and expenses for one-time or non-recurring, extraordinary costs over a time period representing the value received by ratepayers. In approving the use of deferred accounting, a regulatory agency avoids the recovery of these costs over a single time period. While each

regulatory agency may have their own criteria for assessing the appropriateness of deferred accounting treatment, based on our experience, we find these criteria typically include the following:

- The costs subject to deferral are significant;
- The transaction resulting in these costs is considered to be unusual or extraordinary; that is, not a typical component of the utility's cost of service;
- As such, the costs to be deferred are not currently recovered through rates;
- The recovery of these costs will not result in the utility over-earning its authorized return; or if currently overearning, the amounts approved for deferral may be net of the current overearning; and
- The utility must demonstrate that the costs it is seeking recovery of are necessary and reasonable, and that management has been diligent in mitigating these expenses.

MDU asserts that because the expenses associated with the proposed transactions represent unusual, non-recurring expenditures that were not contemplated at the time the current rates were established, and because they are sufficiently large that they could accelerate the timing of a rate case, deferred accounting treatment is appropriate. However, with the exception of Employee Retention, the costs for which the Company is seeking deferred accounting treatment represent the acceleration of the recovery of costs already embedded in rates rather than costs the nature of which are unusual or non-recurring.

If our analysis confirms that MDU appropriately concluded that the benefits of the proposed retirements are greater than the costs described above, and that these benefits accrue to customers over time, then it is also appropriate for MDU's expenses associated with the retirements to be deferred and recovered over time subject to the tasks to be completed as described below.



3 Our Proposed Work Plan

The following work plan is based upon addressing the key issues outlined in the prior chapter using the dual approach of review and critique of the MDU analysis and independent modeling conducted by PA.

Task 1: Frame the issues of concern to the Commission's Advocacy Staff

PA will conduct a project kick-off Workshop via conference call to identify and incorporate Advocacy Staff's (Staff) thoughts and concerns related to the Application. Prior to the Workshop, we will conduct detailed reviews of the Application, IRP, and any additional materials associated with the docket.

The primary purpose of the Workshop will be to conduct detailed discussions with the Staff regarding the Application. PA will facilitate discussions related to:

- The Staff's initial impressions and any potential concerns related to the Application;
- Review of past issues and precedents regarding determining prudence of new resources and approval of deferred accounting petitions;
- PA's proposed project Work Plan and proposed testimony outline; and
- Identification of critical documents and data responses to review including prior dockets and discovery that has already occurred.

We anticipate proposing a comprehensive set of data requests to MDU following the meeting. In addition, based upon our experience with reviewing resource planning modelling, we will prepare an initial set of data requests to MDU to address inputs and assumptions not detailed in the IRP.

Task 1 Work Product:

- Workshop and agreement on Work Plan and testimony outline
- Comprehensive set of data requests

Task 2: Review of MDU's Economic Analysis

We will begin by reviewing the inputs to MDU's EGEAS model used to support the conclusion that retirement of the coal units and constructing a CT is the least cost option. These critical inputs include, but are not limited to:

- Load forecast including consideration of the extent to which distributed generation, energy efficiency, and other load-modifying components are incorporated into the forecasts;

- Fuel prices;
- Wholesale market prices;
- Operating costs and capital requirements assigned to the coal units targeted for retirement; and
- Cost of new generation resources.

In addition, we will review the sensitivity scenarios to assess whether those encompass a reasonable range of scenarios given the inherent uncertainties associated with resource planning.

Task 2 Work Products:

- Evaluation and critique of the reasonableness of key assumptions used in MDU's modeling;
- Critique and review of load forecast assumptions and
- Evaluation and critique of the sensitivity scenarios developed by MDU.

Task 3: Conduct Independent Market Modeling

We will leverage our most recent Base Case view of the MISO energy markets and use the resulting pricing forecasts to evaluate the economics of constructing Heskett 4 compared to market purchases. We will compare our view of Heskett 4's likely dispatch and economics compared to the analysis developed by MDU.

The economic analyses will consist of the following:

- A detailed review of the input assumptions used in both PA's and MDU's analyses, including market and fuel price forecasts, regional supply assumptions, and transmission path assumptions between MISO zones; and
- A comparison of the projected operation of the CT.

Task Products:

Task 3 Work Products:

- Market model of the MISO market and expected dispatch of Heskett 4; and
- Comparison of PA key assumptions with MDU's assumptions.

Task 4: Evaluation of MDU's Proposed Plan to Retire Coal Units and Construct a CT

This task involves the synthesis of tasks 2 & 3 to determine whether retirement of the three coal units and construction of a new CT is the least cost or most reasonable option. While MDU's proposed plan of action may appear to always be the preferred option, we know that there are significant uncertainties surrounding long-range forecasts of fuel and market prices. Therefore, we will focus on identifying any potential risks that may not have been fully explored by MDU. This task will be used to support our recommendations associated with:

- Whether the Commission should approve an ADP;
- Whether the Commission should approve a CPCN; and
- Whether retirement of the coal units is in the interest of the customers.

Task 4 Work Product:

- Discussion and conclusions regarding a recommendation for the CPCN and ADP

Task 5: Evaluate MDU's Petition for Deferred Accounting

PA will assess whether the costs proposed for deferred accounting treatment meet regulatory requirements for deferral, whether these costs were calculated appropriately, and whether the net benefits exceed the costs, and form a recommendation related to these assessments including amortization periods and returns to be earned on unamortized balances.

Our approach is not intended to audit the specific amounts requested for deferral; that is a task for the next general rate case.

Specifically, we will perform the following tasks:

- Review the methodology used by the Company to apportion costs to North Dakota. Confirm that this methodology is consistent with that used in the Company's most recent North Dakota rate proceedings.
- Review the calculation of net book value by plant as of the proposed retirement data from values as of the last general rate case.
- Agree depreciation rates used to those authorized by the Commission.
- Assess the impact of the reversal of accumulated deferred taxes related to the plants and their impact of rates.
- Review the calculation of excess deferred taxes in light of requirements of the TC&JA of 2017 Order.
- Review the detail of retention bonus programs including numbers of employees included and the bonus offerings by category of employee. Assess Company studies supporting the need for this program.
- Based on our assessment, summarize the costs we believe to appropriately be subject to deferred accounting treatment compared to the amounts proposed by the Company in its application. Conclude as to the reasonableness of the amounts subject to deferred accounting treatment.
- Compare the net benefits of the proposed retirements as determined by PA to these costs. Conclude as to the benefit to Montana-Dakota's North Dakota customers.
- Review relevant, recent Orders (e.g., Case Nos. PU-17-270, 271, 322 and PU-09-731, 733, 739) including related settlement agreements.

Task 5 Work Product:

- Develop recommendations for costs allowed for deferred accounting treatment, amortization periods and returns on amounts deferred.

Task 6: Results and Conclusions Review Workshop

We propose to hold a final collaborative review workshop (either in person or via conference call) with Advocacy Staff upon the conclusion of the analyses conducted in Tasks 2 through 5. At the workshop, we will collectively review the modelling results and ensure that we have a common understanding of the results and their implications for North Dakota ratepayers. Pending the discussions at this workshop, we will make revisions as necessary and request Staff's approval of the final testimony outline prior to developing draft testimony.

Task 6 Work Product:

- Review workshop and approval of final testimony outline

Task 7: Preparation of Testimony

While the testimony is yet to be developed, we anticipate that the pre-filed testimony will be based on the work products developed by PA and will address the following:

- Summary of findings and recommendations;
- Review and critique of MDUP modeling assumptions, methodology, and results;

- Findings from additional analysis developed by PA;
- Criteria considered in developing the recommendation regarding the ADP and CPCN; and
- Criteria considered in developing the recommendation regarding the petition for deferred accounting;

The basis of the testimony will be: 1) PA's detailed analysis of the MDU filing, 2) review and analysis of responses to interrogatories, and 3) the PA analysis conducted. Our current plan is for Jim Heidell to file testimony pertaining to the ADP and CPCN and Joel Jeanson to file testimony pertaining to the petition for deferred accounting.

Depending on the procedural schedule, PA will also prepare rebuttal / sur-rebuttal testimony as required.

Task 7 Work Product:

- Direct Testimony addressing the ADP, CPCN, and deferred accounting petition
- Rebuttal / Sur-rebuttal Testimony, if required.

Task 8: Support Formal Proceedings

PA will support the Commission throughout the formal proceedings related to the application for the ADP. This will include presentation of effective oral testimony at the Commission's technical hearings related to the testimony identified in Task7.

While it is difficult to project exactly what types of other support will be required, PA anticipates the support could include:

- Responding to data requests and interrogatories;
- Assisting with potential settlement negotiations;
- Review of direct and rebuttal testimony filed by both the Company as well as any intervenors; and/or
- Other supportive functions as the proceedings progress.

PA will assist the Advocacy Staff's counsel in preparing for cross examination of the Company's and other intervenor witnesses. As the proceeding moves forward, PA anticipates it may be possible the Commission will enter into settlement negotiations with the Company to reach a negotiated settlement. PA will support the Staff during negotiations with analyses as necessary, review of any Company or other intervenor proposed modifications to any proposed Commission decisions, recommendations and support of any modifications the Commission may wish to propose, and other negotiation support as necessary.

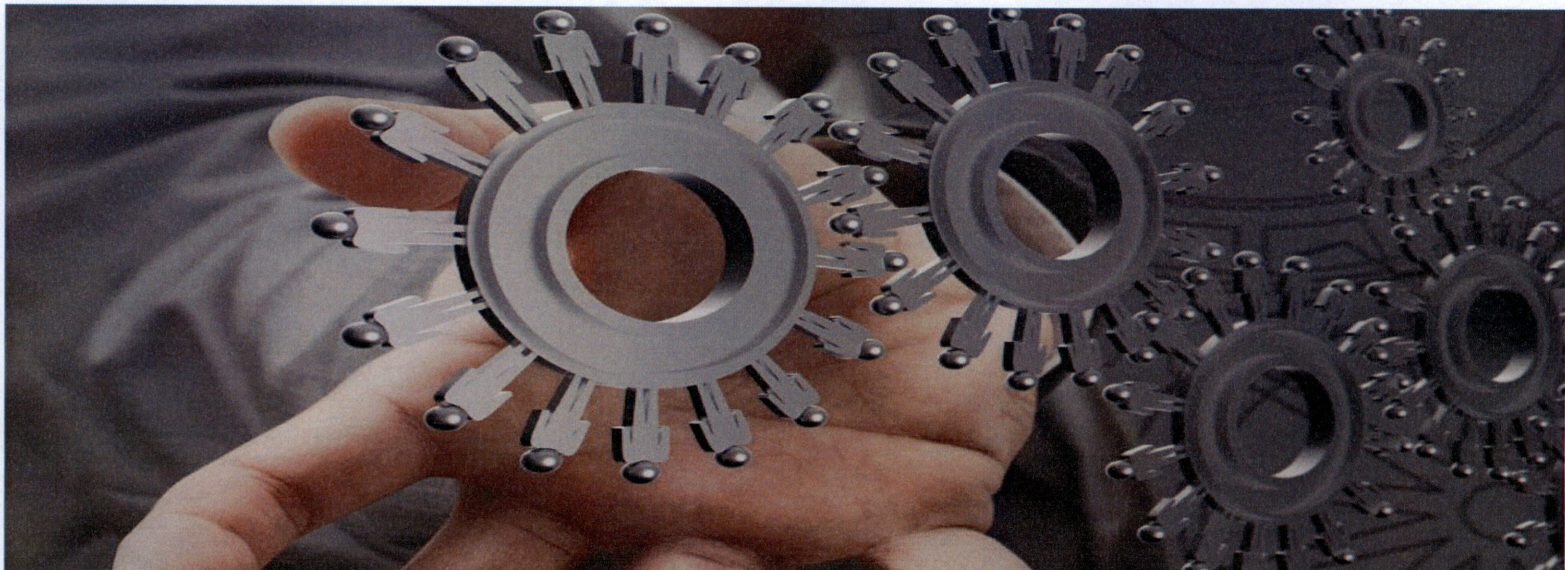
Task 8 Work Product:

- Response to Data Requests and other support as necessary

3.1 Proposed Project Schedule

We have reviewed the schedule provided in the RFP and noted below. We are prepared to assist the Commission and Advocacy Staff in meeting all necessary deadlines and we have sufficient staff resources to adjust to revised schedules. We have developed the following milestones based upon the procedural schedule outlined in the RFP. We anticipate discussing these milestones during the proposed project kick-off workshop and adjusting them as mutually agreed upon or based upon changes ordered by the Commission, and are prepared to revisit the project schedule as the proceedings unfold. We also note that the testimony is due shortly after the holiday period. We will coordinate with Advocacy Staff to allow sufficient review time based upon holiday obligations and vacation schedules.

Milestones	Date
Kick-off meeting	Week of November 11, 2019
First set of interrogatories	Week of November 18, 2019
Additional interrogatories	December, 2019
Review Workshop / meeting	Week of December 16, 2019
Draft of direct testimony	December 23, 2019 – January 3, 2020
Pre-filed direct testimony	January 9, 2020
Review of MDU rebuttal and preparation of interrogatories	Week of February 3, 2020
Preparation of surrebuttal	Week of February 10, 2020
File surrebuttal	February 13, 2020
Attend technical hearings	February, 2020



4 Experience and Qualifications

PA has decades of strategic advisory, energy market analytics, and planning expertise with regulatory agencies, electric utilities, and independent power producers around the world and throughout the United States, and we are committed to critically analyzing decisions that impact ratepayers. We are proud of our reputation for providing unbiased, expert consulting services to entities across the energy industry, as well as our reputation for delivering results of exceptional quality both on time and within budget.

4.1 Our Qualifications

We regularly prepare expert testimony on behalf of clients and evaluate the economics of generator contracts with utilities and other off-takers. This experience both results from and adds to our track record of helping clients consider the full range of benefits, opportunities, and risks associated with electric sector policy and investment decisions.

We have provided below several summaries of completed engagements that speak to our ability to provide the types of services requested by the Commission. These represent only a fraction of our experience; additional information and engagement summaries as well as letters of reference are available upon request.

NDPSC ADVOCACY STAFF: EXPERT WITNESS TESTIMONY

Mr. Heidell and PA provided testimony in five NDPSC proceedings on behalf of the Advocacy Staff of the NDPSC. Five of the proceedings were for ADPs. These proceedings are:

- NSP's 1,550 MW of Wind ADP Application (Case No. PU-17-120)
- NSP's Dakota Range Wind ADP Application (Case No. PU-17-372)
- NSP's Dakota Range III ADP Application (Case No. PU-18-430)
- NSP's Biomass Purchase ADP Application (Case No. PU-17-270)
- NSP's RTF Application (DOCKET NO. E-002/M-16-223)
- Otter Tail Power's Merricourt and Astoria ADP Applications (Case No. PU-17-140, PU-17-141, & PU-17-143)

Mr. Jeanson and PA provided testimony in one NDPSC proceedings on behalf of the Advocacy Staff of the NDPSC.

- NSP's Biomass Purchase ADP Application & Application for Deferred Accounting (Case No. PU-17-270)

INVENERGY: EXPERT WITNESS TESTIMONY

Minnesota

PA submitted rebuttal testimony and appeared before the Minnesota Public Utilities Commission, on behalf of Invenergy Thermal Development LLC, regarding Xcel Energy's petition for Approval of Competitive Resource Acquisition Proposal and Certificate of Need. In addition to preparing rebuttal testimony, PA assisted the client and counsel with strategic analyses and demonstratives in support of direct testimony and cross examination of witnesses.

Rhode Island

PA was engaged by Invenergy to provide market analytics and expert testimony support related to the development of its 1000 MW combined cycle in ISO-NE. PA supported Invenergy throughout the development process, including stakeholder engagement, independent market monitor support and analysis, and development of key elements of the Energy Facility Siting Board (EFSB) permit. As part of the overall EFSB process, PA provided expert testimony related to overall need for the project- including the impact of the project on ratepayers, jobs, and total economic and environmental impacts. PA submitted direct testimony to both the Rhode Island PUC, which resulted in a favorable Advisory Opinion, as well to the Rhode Island EFSB. PA experts also provided rebuttal and supplemental testimony and supported the Invenergy team with cross examination of other experts.

SOUTHWEST GENERATION: EXPERT WITNESS TESTIMONY

PA was twice retained by Southwest Generation, an independent power producer, to provide independent expert testimony in Xcel Energy's resource planning regulatory docket in Colorado (in both 2012 and 2017) to enhance the client's future value opportunities. PA reviewed the utility's current and future resource needs to determine if the proposed resource plan would ensure reliability at the least cost to consumers. As a result of this testimony, the Colorado Public Utilities Commission ordered that Xcel Energy update its Flex Reserves study and file this updated study with Xcel's 2019 ERP filing.

SOLAR CITY: EXPERT WITNESS TESTIMONY

Mr. Heidell and PA provided testimony on behalf of Solar City (Tesla) in Nevada Energy and Arizona Public Service Commission general rate cases. The testimony addressed cost of service and rate design with a focus on the costs of serving roof-top solar customers and appropriate rate design given the cost of service and public policy goals of the respective states. The work included analysis of the rate impacts on both customers participating and not participating in rooftop solar programs.

HAWAII GAS: EXPERT WITNESS TESTIMONY

Mr. Heidell on behalf of PA provided testimony on behalf of Hawaii Gas Company. The testimony addressed appropriate rate design and rate changes to recover the cost of service of each rate class as well as incorporating marginal costs in order to reduce rates for all customers. The testimony also addressed rate simplification and normalization to address both inter-island equity and to make rates more understandable for customers.

SKANSKA: EXPERT WITNESS REPORT

Mr. Heidell prepared an expert witness report regarding the assessment of economic damages associated with modifications and repowering of a large cogeneration project that allegedly did not perform up to contractual commitments. The analysis involved evaluation of lost margins associated with energy sales as well as reduced capacity payments and green power credits. The economic damage assessment involved forecasts of wholesale market prices and developing a technical model of the performance of the facility.

Client Entity	Description	Market
Independent Power Producer	PA was retained by an independent power producer to provide buy-side support in connection with a wind portfolio located in ERCOT, MISO, and PJM. PA provided a memo report on the market assumptions and prices provided by the seller's market consultant, and the reasonableness of the seller's financial model	MISO multiple zones
Oil and Gas Producer	PA was engaged by the global power division of a large oil and gas company that was evaluating their future industrial energy supply and demand needs in the MISO South region.	MISO South
Private Equity Investor	PA was retained by a private equity fund to provide strategic buy-side support in connection with the potential acquisition of a renewable waste-to-energy facility located in Zone 7 of MISO.	MISO Zone 7
Independent Power Producer	PA was engaged by an independent power producer in the potential acquisition of a large wind farm in Iowa. As part of the process, the client sought a market advisor to provide an independent assessment of the MISO electricity market.	MISO Zone 3
Transmission Investor	PA was retained by an investor who was considering an investment in an underground HVDC transmission line and two converter stations that will be capable of transmitting up to roughly 2,000 MW from MISO to PJM.	MISO

4.2 Client References

Skanska	Southwest Generation	SolarCity (Tesla)
Deborah S. Griffin, Partner Holland & Knight 10 Saint James Avenue, 11th Floor Boston, MA 02116 Phone (617) 305-2044 deborah.griffin@hklaw.com	Rob Witwer, General Counsel Southwest Generation 600 Seventeenth St, Suite 2400S Denver, Colorado 80202-2110 (303) 623-2786 witwerr@southwestgen.com	Kevin Auerbacher, Sr. Counsel Tesla 1050 K Street, Suite 101 Washington, DC 20001 (202) 657-3155 kauerbacher@tesla.com



5 Project Team

In addition to our proposed Project Manager, PA proposes to dedicate a core team to this effort. The core team will be supported as necessary by subject matter experts from across PA's organization. Our team members, role, and expected contribution from each team member are provided below.

5.1 Project Team

Role	Name / Title	Contribution to Project
Core Team Member	Matt Mooren Member of PA's Management Group	Partner in charge, advisor for alternative approaches, and potential expert witness testimony
Project Manager	Jim Heidell Director	Prepare and submit testimony, ongoing coordination with the ND PSC staff, day-to-day project management
Core Team Member	Charles Janecek Principal Consultant	Review of MDU's EGEAS analysis, potential expert witness regarding production cost modeling and resource optimization
Core Team Member	Joel Jeanson Principal Consultant	Utility Finance and Accounting
Core Team Member	Grant Gunter Consultant	Energy Analytic and Testimony Draft Consulting
Core Team Member	Caroline Belmont Consultant	Quantitative modeling, MISO market modeling, and other analytic support
Core Team Member	Marwan Charara Analyst	Quantitative modeling, research, and other analytic support

5.2 Team bios

JIM HEIDELL

DIRECTOR, ASSIGNMENT MANAGER

Mr. Heidell specializes in electric and gas utility load forecasting, wholesale electricity markets, evaluation of renewable energy technologies and financial analysis of complex investments. Mr. Heidell assists clients with due diligence associated with acquisition of natural gas and electric utilities and wholesale energy market transactions. 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.

MATT MOOREN

MEMBER OF PA MANAGEMENT GROUP, ENERGY MARKETS EXPERT

Mr. Mooren is an energy and utilities advisor who works across the value chain, including the natural gas, power, coal, renewable sectors and energy infrastructure (fuel-generation-transmission-customer). His 15+ years of consulting experience include working with utilities, private equity firms, competitive generators, global corporations, investment banks, financial advisors, and legal advisors on the associated economic opportunities and risks in the global energy markets. He helps clients navigate through policy, regulatory, market structure, technology, and economic uncertainty to address their business strategy, merger and acquisition, financing, restructuring, litigation, and testimony support needs. He has helped clients develop, build, buy, or sell over \$125 B in energy infrastructure assets across the U.S., including over \$15 B in utility scale wind/solar generation and over \$10 B in transmission projects. Matt has more than a half dozen energy companies build their corporate, distributed energy resource market entry, or transmission investment strategies. Matt has also been the commercial advisor for the purchase or sale of over \$10 B worth of electric, water, and natural gas utilities.

CHARLES JANECEK

PRINCIPAL CONSULTANT, RESOURCE PLANNING EXPERT

Mr. Janecek is an integrated resource planning expert with more than 20 years of experience. Mr. Janecek specializes in generation options analysis engagements, typically focusing on coal and gas retirement planning as well as renewable integration issues such as increased fuel and spinning reserve costs, gas storage costs, coal cycling costs, and renewable energy standards compliance. Prior to PA Consulting, as a senior generation resource planner with an investor owned utility ("IOU"), he was integral to the process of soliciting, evaluating, and procuring more than 2 GW of generating resource, including over 750 MW of wind generation and 80 MW of solar resources. He has modeled every area of the U.S. and Canada, along with many individual control areas within the markets, to support asset valuations, strategic planning initiatives, regulatory proceedings, and litigation proceedings.

JOEL JEANSON

PRINCIPAL CONSULTANT

Mr. Jeanson has over 40 years' experience, primarily in the utility industry. He has expertise in finance and accounting, ratemaking, auditing, performance measurement and benchmarking, performance improvement, planning and budgeting. During his business career, he directed the accounting, auditing, budgeting, and corporate performance departments at a major investor-owned utility located in Indiana. While in consulting, Joel has had significant experience assessing utility performance and providing regulatory support services, working for both utility regulatory agencies and utilities. He began his career with a Big Eight public accounting firm (audit division), working primarily with clients in the utility industry. His core responsibilities include regulatory support, utility finance and accounting, cost allocation and other technical utility accounting studies, and performance improvement. He has testified on several occasions before utility regulatory agencies including the North Dakota PSC (Case Nos. PU-17-271 and 322). Additional recent testimony includes Vermont PSB Case No. 8881 on behalf of the Vermont Department of Public Service in connection with the proposed acquisition of the local telecommunications provider (May 2017).

GRANT GUNTER

CONSULTANT, ANALYTIC AND TESTIMONY SUPPORT

Mr. Gunter has over six years of experience in the energy industry since completing his studies at the University of Colorado School of Law where he focused on energy law, regulation, and policy. He first worked for a major oil and gas producer upon graduating, and then moved to S&P Global Platts where he focused on domestic and international natural gas markets, as well as policy and regulation. Grant became an expert in natural gas markets and has been able to leverage his legal background during his career to bridge the gap between market fundamentals, and policy and regulation.

CAROLINE BELMONT

CONSULTANT, STATISTICAL SUPPORT

Ms. Belmont is a Consultant in PA's Energy and Utilities practice, based out of Denver, CO. Her strong analytical background combined with her passion for presenting data in a fascinating and insightful way has enabled her to gain exposure to a variety of projects while at PA. She is involved in a wide range of PA's workstreams, with a focus on asset dispatch and revenue modelling, financial modelling, and renewable energy market dynamics. Her asset modelling experience includes using stochastic dispatch models to analyze operations and revenues for thermal and renewable generation assets across the U.S., Mexico, and Canada as well as the analyzing the impact of new builds, retirements, and transmission adjustments on various markets. Additionally, she has modelled renewable energy credits across the U.S. (particularly in ISO-NE, NYISO, CAISO, and WECC) and researched a variety of related policy measures. Before coming to PA, she received a dual Bachelor of Arts in Economics and International Relations from Claremont McKenna College where she wrote her thesis on oil wealth management strategies and their geopolitical and economic impacts.

MARWAN CHARARA

ANALYST, STATISTICAL SUPPORT

Mr. Charara is an Analyst in PA's Global Energy and Utilities practice. As part of PA's team, Marwan has been focusing primarily on stochastic dispatch modelling of power generation assets across the US. In addition, he has been assisting with capacity compensations modelling, ancillary services revenues, and renewable energy policies and market developments. Marwan holds a BE in Chemical Engineering from the American University of Beirut, and an MS in Environment and Sustainability from the University of Michigan, with a dual focus in Sustainable Systems and Environmental Policy & Planning.



6 Cost Proposal

Our cost proposal is divided into two stages. The first stage is for the Collaboration Kickoff and Review Workshops and the development of the support for recommendations related to the ADP, CPCN, and deferred accounting petition (Tasks 1-6). The second stage covers the support of the Commission's formal proceedings (Tasks 7-8).

Based on the two-stage services in Tasks 1 through 8 above, PA proposes to support the Commission's decision on the Advanced Determination of Prudency on a time and materials basis. PA's estimate of the professional fees for Tasks 1-8 is \$147,755, inclusive of estimated travel expenses.

Requests by the Commission for work in addition to those described in Tasks 1-8 above will be performed on a time and materials basis at the hourly rates provided below. Any such work conducted will be defined via a Scope of Additional Services, and incremental costs estimated and agreed to by the Commission prior to the commencement of the additional services.

Travel expenses for the two Collaboration Workshops will be invoiced at cost, and meals and miscellaneous expenses while traveling overnight will be billed on a daily allowance basis based on IRS guidelines for domestic travel.

PA Team Member	Labor Category	Hourly Rate \$/hr	Collaboration Workshops and Supporting Testimony Analysis	Testimony and Formal Proceedings Support
Matt Mooren	Member of Management	595	0	1
Jim Heidell	Director	530	56	32
Charles Janecek	Principal Consultant	350	48	28
Joel Jeanson	Principal Consultant	350	40	32
Grant Gunter	Consultant	305	40	24
Caroline Belmont	Consultant	305	28	8
Marwan Charara	Analyst	230	58	16
Total Hours			270	141
Labor Costs			94,560	51,995
Travel			-	1,200
Total Budget			94,560	53,195

7 Required Enclosures

7.1 Purchase Service Agreement Deviations and Exceptions

PA assumes that this work could be completed under the same contract terms recently accepted related to RFPs 408.17.02.006, 408.17.04.008, 408.17.05.009, 408.17.08.011, 408.17.10.012 and 408.19.01.005.

APPENDICES

Amendments	27
Resumes	31
Example Pre-filed Testimony – Jim Heidell	50
Example Pre-filed Testimony – Joel Jeanson	86

Amendments

**STATE OF NORTH DAKOTA
NORTH DAKOTA PUBLIC SERVICE COMMISSION
PUBLIC UTILITIES DIVISION
600 E Blvd. Ave. Dept. 408
Bismarck, ND 58505-0480**

SOLICITATION AMENDMENT #1

September 25, 2019

Solicitation Number: 408.19.09.010

Title: Montana-Dakota Utilities Co. Advance Determination of Prudence and Certificate of Public Convenience and Necessity – Heskett 4 Case. Nos. PU-19-306 and PU-19-307

Deadline for Receipt of Proposals: October 23, 2019 2:00 PM CT

Solicitation Issued: September 13, 2019

RFP Title is amended as follows:

Montana-Dakota Utilities Co. Advance Determination of Prudence, Certificate of Public Convenience and Necessity – Heskett 4, and deferred accounting treatment Case. Nos. PU-19-306, PU-19-307, and PU-19-317.

Purpose of RFP is amended as follows:

Solicit proposals to analyze the advance prudence, certificate of public convenience and necessity, and deferred accounting treatment applications and provide testimony on behalf of the ratepayers of Montana-Dakota Utilities Co.

Section 1.01 is amended as follows:

The North Dakota Public Service Commission, hereafter known as "purchasing agency," "State," or "Commission" is soliciting proposals for a thorough analysis of the advance determination of prudence and certificate of public convenience and necessity applications for constructing, owning and operating Heskett 4, which is an 88 MW simple cycle combustion turbine submitted by Montana-Dakota Utilities Co. (MDU). The Commission also requires an analysis of MDU's application for deferred accounting treatment in case PU-13-317 for early retirement of 3 coal units which create the need for the Heskett 4 unit.

Section 2.02 is amended as follows:

In accordance with state law, an application fee from the applicant in the amount of \$175,000 is required when an advanced determination of prudence application is filed. Upon request of the commission and with the approval of the emergency commission, the applicant shall pay such additional fees as are reasonably necessary for completion of the application process by the commission.

The budget for this project is capped at \$200,000.

Section 3.01 is amended as follows:

Overview

The North Dakota Public Service Commission, Public Utilities Division, is soliciting proposals for a thorough analysis of the advance prudence and certificate of public convenience and necessity applications, as well as the application for deferred accounting treatment. The selected offeror will be

required to provide written testimony and present effective oral testimony at the commission's technical hearing and assist in the preparation of pre- and post-hearing documents or possibly documents for purposes of moving to dismiss the application.

Description of Specific, Results-Oriented Tasks

The selected offeror must provide a detailed analysis and conclusions related to the necessity and economic prudence for MDU's proposal to build own and operate the Heskett 4 facility, and the deferred accounting treatment request for early decommissioning of 3 coal units.

Section 5.05 is amended as follows:

Cost Proposal Score

Twenty-five possible points will be added to the scores from 5.01 through 5.04 based on the following cost proposal matrix.

The total cost proposal amount will be taken times 0.000125, rounded to the nearest whole number and subtracted from 25. Below are examples of the scores for relative cost amounts.

0 points will be added for a cost proposal equal to or above the total project budget of \$200,000.

5 points will be added for a cost proposal equal to \$160,000.

10 points will be added for a cost proposal equal to \$120,000.

15 points will be added for a cost proposal equal to \$80,000.

20 points will be added for a cost proposal equal to \$40,000.

25 points will be added for a cost proposal equal to \$0.

Section 6.06 is amended as follows:

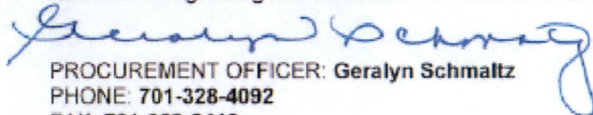
Cost Proposal

The budgeted cost for this project is capped at \$200,000. Even though the budget is set at \$200,000, cost proposals must include an itemized list of projected direct and indirect costs associated with the performance of the contract, including total number of hours at various hourly rates, direct expenses, overhead and so on.

All costs associated with the contract must be stated in U.S. currency. Any commodities being imported must be identified, and the price must include any applicable customs, brokerage agency fees, and duties.

Bidders are instructed to acknowledge receipt of and compliance with this amendment by signing below and returning the Solicitation Amendment Acknowledgement page with your solicitation response.

Questions regarding this amendment must be submitted in writing to the Procurement Officer.



PROCUREMENT OFFICER: **Geralyn Schmaltz**

PHONE: 701-328-4092

FAX: 701-328-2410

TTY Users call: 7-1-1

E-MAIL: gschmaltz@nd.gov


AMENDMENT ACKNOWLEDGEMENT

Solicitation Number: 408.19.09.010

Title: Montana-Dakota Utilities Co. Advance Determination of Prudence, Certificate of Public Convenience and Necessity – Heskett 4, and deferred accounting treatment Case Nos. PU-19-306, PU-19-307, and PU-19-317

Solicitation Amendment Number: #1

By my signature below, I hereby acknowledge receipt of and compliance with this amendment.

COMPANY NAME PA Consulting Group, Inc.
SIGNATURE 
PRINTED NAME Matt Mooren
TITLE Member of PA's Management Group
DATE October 21, 2019

Resumes

MATT MOOREN

MEMBER OF PA'S MANAGEMENT GROUP



Mr. Mooren is an energy and utilities advisor who works across the value chain, including the natural gas, power, coal, renewable sectors and energy infrastructure (fuel-generation-transmission-customer). His 15+ years of consulting experience include working with utilities, private equity firms, competitive generators, global corporations, investment banks, financial advisors, and legal advisors on the associated economic opportunities and risks in the global energy markets. Mr. Mooren helps clients navigate through policy, regulatory, market structure, technology, and economic uncertainty to address their business strategy, merger and acquisition, financing, restructuring, litigation, and testimony support needs. Mr. Mooren has helped clients develop, build, buy, or sell over \$125 B in energy infrastructure assets across the U.S., including over \$15 B in utility scale wind/solar generation and over \$10 B in transmission projects. Matt has more than a half dozen energy companies build their corporate, distributed energy resource market entry, or transmission investment strategies. Matt has also been the commercial advisor for the purchase or sale of over \$10 B worth of electric and natural gas utilities.

PRIMARY EXPERTISE

- Energy policy and regulations
- Power market economics and operations
- Valuation of physical and financial assets
- Gas, power, and coal market dynamics
- Next generation utility foresight
- Litigation support and expert testimony drafting
- Regulated and de-regulated energy investment advisory (including DERs and transmission)
- Merger, acquisition, and financing advisory
- Contract negotiations

CLIENTS

- Electric utilities such as PNM Resources, Cleco, ITC, PPL, AEP, We Energies, LIPA, NYPA, and Austin Energy
- Competitive generators such as Invenergy, Intergen, and SWGen
- Investment banks such as Barclays, Citi, and Goldman Sachs
- Multiple private equity investors such as PGGM, John Hancock, and Macquarie

QUALIFICATIONS

- B.S. Industrial Engineering

EXPERIENCE SUMMARY

- **Energy Policy and Regulations.** – Matt is experienced in energy policy review, analysis, and guidance. This includes interpreting how existing and potential federal and state policy-making and regulation affect the natural gas, power, coal, and renewable sectors within which regulated companies and energy infrastructure assets operate.
- **Energy Market Economics and Operation** – As a core contributor to the development of PA's energy market forecasting models since 2000, Matt maintains an intimate understanding of the fundamentals underlying natural gas, power, and renewable markets. Matt advises clients on the value that may be derived from within the operations of all North American energy markets, including those with regulated (vertically integrated electric utilities and gas utilities) and de-regulated (wholesale power markets) characteristics.
- **Valuation of Physical and Financial Assets** – Matt has extensive experience valuing a wide array of physical and financial energy assets and energy organizations, with extensive experience valuing power generation assets and contracts in particular. Matt has valued over \$125 billion in power generating assets, including the analysis of

hydroelectric, pump storage, wind, solar, biomass, geothermal, battery storage, hybrid solar-thermal, cogeneration, nuclear, coal, and natural gas as well as power and fuel contracts, financial hedges, and trading books.

EXPERIENCE

Municipal Utility

Mr. Mooren has been an energy advisor for a large U.S. municipal utility. Due to the municipality's electric rates recently becoming greater than its regional peers, the utility has faced significant pressure from its customers and state regulators to deregulate and allow its customers to engage in retail choice. Matt led the team in conducting an innovative and robust analysis to help the municipal utility assess the impacts of retail choice and inform the utility's regulators on the risks and benefits associated with retail choice from the perspectives of the customer, the utility, and the city.

PA utilized its proprietary FutureWorlds approach to help the utility forecast the impacts of retail choice on its business model in both a low and high future market price environment. Using this tool and working hand-in-hand with key utility team members, PA quantitatively assessed the stakeholder benefits and costs of maintaining the utility's current vertically integrated structure versus deregulating. The analysis included factors such as rates, stranded asset risk, community programs, and the general funds transfer from the utility to the city. PA demonstrated how deregulation may provide a short-term benefit to customers in a low market price environment but create serious long-term financial risks for its customers in a high market price environment. Additionally, PA demonstrated altering the current vertically integrated structure would reduce the overall system benefits to the customer, the utility, and the city.

PA's analysis was used by the municipal utility's executives during its strategic planning process to develop robust 'no regrets' initiatives to plan for both the status quo and the possibility of moving towards retail choice. Additionally, the utility's executives utilized PA's analysis as a communication tool with its primary regulator to help inform the regulators of the financial and policy implications opening up the utility to retail choice.

Southeast IOU

Matt has led PA as the energy economic advisor for a Southeast U.S. electric utility since 2008. The electric utility faced several challenges including the ownership of a competitive generation business, a shortage of regulated generation supply to meet customer demand, potential opportunities to expand customer base by serving additional municipality or cooperative electric demand, and potential opportunities from integration into the MISO wholesale electricity market.

PA leveraged its regulatory, natural gas, power, coal, transmission, electric utility, and competitive generation business expertise to assess the utility's competitive landscape. The primary focus was on the regulations and fundamentals affecting the electric utilities, non-regulated generators, and associated transmission for Louisiana. Matt facilitated several working sessions with the utility's executive management team and presented to the board of directors. PA's work assisted the utility in establishing a solid foundation for growth. The utility has since reduced their competitive generation exposure, reduced their shortage of regulated generation to meet customer demand, and increased their customer base. The utility won the EEI award for shareholder growth in 2012.

Southwest IOU

Mr. Mooren has led PA as the energy economic advisor of a Southwest U.S. electric utility since 2011. The utility possessed a competitive generation business in Texas which created cash flow, earnings, share price, and credit rating risk to the utility's core business as a regulated electric utility. PA conducted a market opportunity and risk assessment of the Texas wholesale electricity market, as well as a valuation of the electric utility's regulated business and competitive generation assets. PA's work, including executive management and board communication, helped the utility decide to sell the competitive generation business and obtain regulatory approval. The sale simplified Southwest IOU's business and market position.

The electric utility faced federal environmental regulations and low natural gas prices which caused it to consider de-risking from coal within their portfolio of regulated power generation supply. PA helped develop a decision framework. PA then assessed customer impact of a myriad of potential environmental compliance, new build, replacement and acquisition alternatives with the objective of choosing a least cost/lowest risk path, while also considering stakeholder (political, regulator, shareholder, and intervener) requirements. PA's work assisted the Southwest IOU in the development of its strategic roadmap and subsequent steps to execute.

Competitive Generator

Matt has led PA as the energy economic advisor for a Western U.S. competitive generation owner since 2012. In CO, PA helped the competitive generation owner develop a re-contract negotiation strategy, drafted expert testimony, and testified before state regulatory commission. PA also analyzed a CO electric cooperative's supply mix and future electric rates- assuming the client's generators were part of the electric cooperative's generation portfolio- and presented its independent perspective to the cooperative's general manager. PA developed contract re-negotiation and generator divestment strategies for the competitive generation owner's NV assets

ADDITIONAL EXPERIENCE

- **M&A/Finance/Development** – typically work with private equity firms- and their finance, legal, tax, and engineering advisors by communicating industry leading investment perspective and overseeing the creation of work products to help make transactions happen;
- **Business Strategy** – typically hired by electric utilities or competitive generation owners to enhance stakeholder value by delivering industry perspective and work products to help them navigate through an uncertain political/regulatory, market structure, market fundamental, and energy economic environment; and
- **Restructuring/Litigation/Testimony** – typically work with lawyers, on behalf of competitive generators or electric utilities, to create strong economic arguments and resolve disputes within regulatory, litigation, and bankruptcy processes.

JIM HEIDELL

DIRECTOR



Jim Heidell specializes in electric and gas utility regulation, wholesale electricity markets, evaluation of renewable energy technologies and financial analysis of complex investments. Mr. Heidell assists clients with due diligence associated with acquisition of natural gas and electric utilities and wholesale energy market transactions. 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
- Comisión 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.

- **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

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

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

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 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 – 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.

CHARLES JANECEK

PRINCIPAL CONSULTANT



Mr. Janecek provides a unique blend of commercial consulting and utility planning experience to PA's clients. With more than 20 years of experience in the electric power industry through previous positions with an investor-owned utility (IOU) and private consulting firms. At PA, Mr. Janecek manages resource planning engagements, often focusing on energy storage and renewable integration issues. As a resource planning expert, in recent years he has seen a significant increase in utility desires to evaluate storage opportunities and has helped utilities and developers alike think about what markets are going to emerge for energy storage. He has been an integral component in several energy storage engagements, ranging from utility specific procurement assistance to detailed valuations of proposed storage facilities. While a senior planner with an IOU, he was integral to the process of soliciting, evaluating, and procuring more than 2 GW of generating resource additions to the IOU system, including over 750 MW of wind generation and 80 MW of solar resources. When advising clients involved in wholesale markets and asset transactions, Mr. Janecek applies experience gained analyzing and facilitating transactions for more than 500 assets. He has modelled every area of the U.S. and Canada, along with many individual control areas within the markets, to support asset valuations, strategic planning initiatives, regulatory proceedings, and litigation proceedings.

PRIMARY EXPERTISE

- Integrated Resource Planning
- Energy storage opportunity analysis
- Utility operations
- Power market economics and operations
- Valuation of physical and financial assets
- Gas, power, and coal market dynamics
- Litigation support and expert testimony drafting
- Contract negotiations

CLIENTS

- Xcel Energy
- Pacific Gas & Electric
- San Diego Gas and Electric
- Hoosier Rural Electric Cooperative
- North Dakota Public Service Commission

QUALIFICATIONS

- B.S. Geology

EXPERIENCE SUMMARY

- **Integrated Resource Planning** – Charles has led several integrated resource planning assignments. The assignments have ranged from detailed scenario planning, fundamental and stochastic-based production cost modeling, dynamic capacity expansion optimization, management and regulatory presentations, and stakeholder engagement support.
- **Energy Storage Opportunity Analysis** – Charles has led multiple energy storage evaluations, ranging from pumped hydro storage, Compressed Air Energy Storage (CAES), and battery storage analyses, as well as an investigation of the potential for customer grid defection for utilities resulting from behind the meter storage.
- **Utility Operations** – Over the course of his career, Charles has been intimately involved with advising utilities on a wide range of utility operations. He has led solar and wind generation integration analyses, evaluating the impact these intermittent resources have on the operations and dispatch of the balance of system resources. Charles has evaluated the operations of pumped storage hydro resources for their ability to provide ancillary services to a given utility's system as well as the wider markets.

- **Power Market Economics and Operations.** Charles has analyzed and facilitated transactions for more than 500 assets. He has modeled every area of the U.S. and Canada, along with many individual control areas within the markets, to support asset valuations, strategic planning initiatives, regulatory proceedings, and litigation proceedings.
- **Valuation of Physical and Financial Assets.** Charles has conducted detailed dispatch projection analyses for assets located in regional transmission organizations and power markets, as well as bilateral, utility-based markets. He has analyzed hydroelectric, pumped storage, wind, biomass, geothermal, battery storage, hybrid solar-thermal, cogeneration, nuclear, coal, and natural gas as well as power and fuel contracts, financial hedges, and trading books.

EXPERIENCE

U.S. Investor Owned Utility

Mr. Janecek led several engagements with a Midwestern utility to provide independent evaluator and auditing services. As independent evaluator, Mr. Janecek led analyses to independently verify financial and production cost modeling conducted to support utility self-build projects as well as independent power producer bids. As independent auditor, Mr. Janecek led efforts to audit competitive procurement solicitations, including bidder communications monitoring, bid due diligence efforts, analysis review, and contract negotiations monitoring.

Western U.S. Investor Owned Utilities

At PA, Mr. Janecek is an integral member of the PA team currently supporting two major western US IOUs in their competitive procurement process. PA provides independent evaluator services to both utilities, which requires the submittal of independent evaluators' reports to regulatory commissions certifying the fairness and equitable treatment of all bidders. These independent evaluation services require communications and contract negotiations monitoring, bids and analysis review, and regulatory reporting.

City of Burbank Water and Power

Mr. Janecek led the effort with BWP to quantify the uncertainties BWP faces as it considers the pending shutdown of the Intermountain Power Project. He guided BWP in developing portfolio scenarios for evaluation, then conducting stochastic production cost modeling to quantify the impacts that various resources will have on BWP and its ratepayers. BWP's IRP evaluated a compressed air energy storage (CAES) facility as a potential source of ancillary services for BWP, and Mr. Janecek provided analytical support for that evaluation as well.

Caribbean Island Utility

Mr. Janecek led the development of a comprehensive integrated resource plan for this island utility. A key component of the IRP was the development and production cost modeling of various resource portfolio scenarios. He collaborated with the client to utilize a structured framework for the development of those scenarios, providing a defensible and comprehensive approach toward defining the possible paths for the utility. He then performed production cost modeling to quantify the scenarios including analysis of the system energy and demand requirements, conservation and energy efficiency opportunities, potential fuel infrastructure requirements related to liquefied natural gas and potentially liquid petroleum gas (propane), projected penetrations of distributed solar generation, potential new supply construction of thermal and renewable resources, and potential impacts to the utility's transmission and distribution systems and associated upgrade requirements.

Midwest IOU

Mr. Janecek led several wind integration efforts, working with the IOU's Energy Supply, Commercial Operations, and Resource Planning groups. He performed specialized modeling analyses to quantify the costs for procuring and dispatching intermittent wind resources. He helped design a state-of-the-art wind generation forecasting system in coordination with the National Renewable Energy Laboratory and National Center for Atmospheric Research.

Additionally, Mr. Janecek conducted a multi-year study to identify expected O&M costs related to extensive cycling of coal-fired plants due to wind generation. The study quantified the number of significant ramping events for each coal-fired plant on the system and then applied a cost per cycle to estimate annual cycling costs. These costs were compared to the estimated costs of curtailing the expected wind generation in place of ramping down the coal units.

Commonwealth Utilities Company (CUC), Saipan

Mr. Janecek managed the development of a new 20-year IRP covering 2015–2038. He worked with CUC system planners to create an energy supply RFP targeted at new supply construction vendors, seeking proposals for new supply options on Saipan. Upon receipt of those proposals, he worked with CUC to evaluate and shortlist the proposals for consideration in the IRP. The engagement also involved working with CUC throughout its stakeholder engagement process to identify community concerns relative to the IRP development and ensure that ultimately the IRP reflected those concerns.

A primary task in this IRP engagement was to parameterize and model each of CUC's generating units and power purchase contracts, as well as other system-level inputs. Production cost modeling was run for a base case model of the CUC system, as well as stochastic scenario modeling (20-year forecasts describing the range of expected values for fuel, fixed operations and maintenance (O&M), and variable O&M). Parameters of various demand-side management measures and demand response programs were evaluated in the scenario modeling.

JOEL JEANSON

PRINCIPAL CONSULTANT



Joel has extensive experience in utility finance and accounting, financial and operational auditing, performance improvement, budgeting and management reporting, shared services, and utility ratemaking. During his business career, he directed the accounting, budgeting, corporate performance and auditing departments at a major investor-owned utility. He began his career with a Big Eight public accounting firm. He has testified before several utility regulatory commissions. His core responsibilities include technical regulatory accounting studies, due diligence, performance diagnostics, and process design and implementation.

PRIMARY EXPERTISE

- Corporate performance management
- Performance improvement
- Regulatory accounting/Cost allocations
- Management audits
- Due diligence

CLIENTS

- LADWP
- SUEZ
- National Grid
- Private Equity Firms

QUALIFICATIONS

- Licensed CPA (inactive)
- Bachelor of Science in Business (Accounting Major)

EXPERIENCE SUMMARY

- **Corporate performance management** – assisting clients improve performance by improving processes whereby strategic plans are aligned with business unit, functional and individual performance including performance measurement and management reporting processes
- **Performance Improvement** – helping clients improve business processes through benchmarking and focus on value-adding activities
- **Regulatory accounting** – helping clients improve cost allocation practices to mitigate regulatory risks and improve decision-making; completing specialized technical accounting and cost studies to support regulatory accounting and compliance activities
- **Management Audits** – performing compliance, efficiency, and effectiveness audits of utilities on behalf of utility regulatory agencies and assisting utility clients prepare for upcoming management audits
- **Due diligence** – assist investors by assessing accounting and regulatory conditions and practices in connection with M&A and investment transactions

EXPERIENCE

National Grid

Developed companywide cost allocation practices in conjunction with the implementation of SAP; provided regulatory support associated with new practices. Completed A&G capitalization study. Met with NY PSC Staff to present results for both studies.

SUEZ Water

Performed independent assessment of service company costs and allocation practices. Updated Cost Allocation Manual and associated practices.

Confidential Client

Assessed opportunities for investments in the US water industry including an analysis of the regulatory environment by state.

PSE&G

Provided support to the Company in preparing for an upcoming management audit. This included performing a diagnostic assessment of potential audit risks and employee training. Lead consultant for the review of cost allocations and related controls to ensure the utility was not subsidizing non-regulated operations for a large, east coast gas & electric utility in advance of a state regulatory commission-mandated management audit.

HECO

Directed the development of a corporate financial model; supported finance process improvement activities; completed specialized regulatory accounting studies; performed financial modeling to support business design changes.

Washington Gas

Provided assistance in identifying potential merger synergies for support services functions.

EPCOR

Completed special study filed with the Alberta regulatory commission related to cost allocation practices and shared services.

LADWP

Assessed the effectiveness of, and designing improvements to, the process whereby the Department's strategic plan is linked to and integrated with business unit and functional plans. Directed the completion of water system revenue requirements, cost of service and rate design studies.

FirstEnergy-Pennsylvania

Assessed the effectiveness of the corporate management process and suggested changes to the process to better ensure the transparency of the process and linkages to operational plans and budgets.

Vectren

Performed a process improvement and benchmarking study of the corporate performance management process. Completed analyses of regulatory accounting practices following a major acquisition. While with Vectren, finance lead on merger integration activities.

Private Equity

Performed due diligence in connection with acquisitions of and / or investments in regulated utilities focused on regulatory environment and technical accounting issues.

PNM Resources

Performed series of technical accounting studies.

GRANT GUNTER, J.D.

CONSULTANT, ENERGY AND UTILITIES



Grant has over six years of experience in the energy industry since completing his studies at the University of Colorado School of Law where he focused on energy law, regulation, and policy. He first worked for a major oil and gas producer upon graduating, and then moved to S&P Global Platts where he focused on domestic and international natural gas markets, as well as policy and regulation. Grant became an expert in natural gas markets and has been able to leverage his legal background during his career to bridge the gap between market fundamentals, and policy and regulation.

PRIMARY EXPERTISE

- Natural gas and energy markets fundamentals analysis
- Energy law, regulation, and policy
- Market research
- Energy infrastructure
- Litigation support

CLIENTS

- Middle River Power
- Sumitomo
- Public Service Enterprise Group
- GenOn

QUALIFICATIONS

- J.D, University of Colorado School of Law

EXPERIENCE SUMMARY

- **Statistical Analysis and Forecasting.** Desmond has developed models in Python, R, and Excel to support strategic decision-making. This work includes forecasting retail electric rates, loads, and capital costs, as well as using predictive price models to support risk analysis.
- **Energy Policy.** Desmond conducts extensive research of U.S. energy policies at the state, regional, and federal levels, analyzing the scope of such policies as well as their market impacts.
- **Market Research.** Desmond has experience analyzing the competitive landscapes for various energy markets, such as energy storage and retail electric sales.

CAROLINE BELMONT

CONSULTANT



Caroline is a Consultant in PA's Energy and Utilities practice, based out of Denver, CO. Her strong analytical background combined with her passion for presenting data in a fascinating and insightful way has enabled her to gain exposure to a variety of projects while at PA. She is involved in a wide range of PA's workstreams, with a focus on asset dispatch and revenue modelling, financial modelling, and renewable energy market dynamics. Her asset modelling experience includes using stochastic dispatch models to analyse operations and revenues for thermal and renewable generation assets across the U.S., Mexico, and Canada as well as the analysing the impact of new builds, retirements, and transmission adjustments on various markets.

Additionally, she has modelled renewable energy credits across the U.S. (particularly in ISO-NE, NYISO, CAISO, and WECC) and researched a variety of related policy measures. Before coming to PA, she received a dual Bachelor of Arts in Economics and International Relations from Claremont McKenna College where she wrote her thesis on oil wealth management strategies and their geopolitical and economic impacts.

PRIMARY EXPERTISE

- Asset Dispatch Modelling
- Financial Modelling
- Energy Policy Research
- Renewable Energy Credit Forecasting
- Fundamental Market Analysis
- Economic Forecasting
- Renewable Policy Impact Analysis

CLIENTS

- Independent Power Producers
- Integrated Utilities
- Cooperatives
- Private Equity Groups

QUALIFICATIONS

- BA, Economics and International Relations – Claremont McKenna College

EXPERIENCE SUMMARY

- **Economic Forecasting** – Caroline is experienced in econometrics, statistical analysis, regression methods and analysis, and macroeconomic theory and application.
- **Financial Modelling** – Caroline holds expertise in various financial modelling concepts and techniques, including DCF valuation, financial statement analysis, Monte Carlo simulation, Value at Risk and alternative risk metrics.
- **Renewable Modelling** – Caroline is extensively involved in PA's modelling of renewable levelized costs, valuation of renewable generation assets, and Renewable Energy Credit modelling across the U.S.
- **Senior Thesis** – A Critical Examination of Oil Wealth Management Strategies and Their Effects on Economic Growth in the GCC Countries

MARWAN CHARARA

ANALYST



Mr. Charara is an Analyst in PA's Global Energy and Utilities practice. As part of PA's team, Marwan has been focusing primarily on stochastic dispatch modelling of power generation assets across the US. In addition, he has been assisting with capacity compensations modelling, ancillary services revenues, and renewable energy policies and market developments. Marwan holds a BE in Chemical Engineering from the American University of Beirut, and an MS in Environment and Sustainability from the University of Michigan, with a dual focus in Sustainable Systems and Environmental Policy & Planning.

PRIMARY EXPERTISE

- Stochastic Modelling
- Capacity Compensation
- Ancillary Revenues
- Renewable Energy
- Market Research

QUALIFICATIONS

- MS, Sustainable Systems and Environmental Policy, School for Environment and Sustainability, University of Michigan
- BE, Chemical Engineering, American University of Beirut

EXPERIENCE SUMMARY

- **Stochastic Modeling:** Marwan has operated PA's proprietary stochastic model to project cash flows and operations of power plants and energy contracts.
- **Capacity Markets:** Marwan focuses on the new developments in the New England capacity market through extensive market research. He operates PA's capacity market models to forecast capacity prices for the different zones in the US power markets.
- **Ancillary Revenues:** Marwan operates PA's ancillary services models to project asset specific ancillaries across the US power markets.
- **Renewable Energy:** Marwan worked on a due diligence report for a client looking to evaluate an investment in a portfolio of solar assets across the US.
- **Market Research:** Marwan performs extensive market research on US energy and environmental policies, particularly renewable-related energy policies and their potential impacts on energy and capacity markets.

EXPERIENCE

Student Consultant – University of Michigan

January 2017 – March 2018

Developed a framework to help small and medium-sized commercial and industrial energy customers in Europe procure affordable renewable energy through ECOHZ Renewable Energy Foundation and identified the economic and environmental benefits of their GO2 that builds on the concept of guarantees of origins and provides 'additionality'.

Research Assistant – University of Michigan

November 2016 – September 2017

Evaluated the impacts of light-weighting shipping containers on their production, use, and end of life. Assessed and modelled the respective reductions in fuel usage, energy demand, and greenhouse gas emissions for different shipping modes both on a national and global levels.

Example Pre-filed Testimony – Jim Heidell

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-18-430

ADVANCE DETERMINATION OF PRUDENCE – DAKOTA RANGE III WIND FACILITY

TABLE OF CONTENTS

I. Introduction	3
II. Summary of Recommendations	5
III. Summary of Findings	7
IV. The Impetus for the PPA	8
V. Summary of Dakota Range III PPA	11
VI. Summary of Data Center Retail Electric Service Agreement	13
VII. Evaluation of the ADP Application	14
VIII. Need Assessment of the Project	16
IX. Evaluation of the Company's Economic Analysis of the Project	18
X. Evaluation of NSP's Supplemental Strategist Runs	23
XI. Independent Economic Analysis of the Project	26
XII. Assessment of the Projected Energy Cost Savings of the Project	28
XIII. Allocation of Generation Demand Costs	29
XIV. Accounting for Fuel & Purchase Power Cost if ADP is Rejected	30
XV. Other Considerations	33

1 **I. Introduction**

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

3 **A.** My name is James A. Heidell. I am a Director at PA Consulting Group, Inc. (PA). My
4 business address is 1700 Lincoln Street, Suite 3550, Denver, CO 80203.

5
6 **Q. On whose behalf are you filing this testimony?**

7 **A.** I am filing this testimony on behalf of the Advocacy Staff of the North Dakota Public
8 Service Commission (Commission or NDPSC).

9
10 **Q. Please summarize your qualifications and experience.**

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

18
19 **Q. Have you testified before the North Dakota Public Service Commission previously?**

20 **A.** Yes. I testified on behalf of Montana-Dakota Utilities in the matter of Montana-Dakota
21 Utilities Co., and Otter Tail Corporation; Advance Determination of Prudence, Big Stone
22 II Generating Station Case Nos. PU-06-481 and PU-06-482. I have submitted pre-filed
23 direct testimony on behalf of Advocacy Staff in the following dockets:

- 24 • Northern States Power Company's request for an Advanced Determination of
25 Prudence for Dakota Range, Case Number PU-17-372
- 26 • Northern States Power Company's request for an Advanced Determination of
27 Prudence for 1,550 MW of Wind, Case Number PU-17-120;
- 28 • Otter Tail Power Company's Request for an ADP for the Astoria CT and
29 Merricourt Wind Project, Case Nos. PU-17-140, PU-17-141, and PU-17-143;

- 1 • Advance Prudence – Biomass Application for deferred accounting Northern
- 2 States Power Company, Case Nos. PU-17-270, PU-17-271, and PU-17-322
- 3 • Northern States Power Company Resource Treatment Framework, Case Nos. PU-
- 4 12-813 et al.

5
6 **Q. What is the purpose of your testimony?**

7 A. The purpose of my testimony is to provide the Commission with my assessment of the
8 Northern States Power Company's (NSP or the Company) request for an Advance
9 Determination of Prudence (ADP) for the proposed Power Purchase Agreement (PPA)
10 between the Company and the Dakota Range III Wind Project (Project).

11 The Company has applied (Application) for an ADP for the Project, indicating to the
12 Commission that the Project is priced below the Company's system average cost and will
13 therefore result in ratepayer savings. Additionally, in its Application the Company states
14 that the Project's renewable energy attributes are needed in association with a separate
15 Retail Electric Service Agreement (RESA) the Company has executed with a new electric
16 service customer in Minnesota.¹

17 My testimony provides the Commission with my evaluation of the Project's economics
18 and associated impacts on the Company's North Dakota customers and ultimately my
19 recommendation of whether or not the Commission should approve the ADP.
20

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

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

- 26 • A summary of my recommendations (Section II);

¹ The customer is not named in the NSP North Dakota application. However, in public documents filed with the MPUC the customer is identified as Google and is also referred to as the Becker Data Center. The actual Retail Electric Service Agreement is signed with an entity called Honeycrisp Power LLC.

- 1 • A summary of my findings (Section III);
- 2 • An overview of the Situation (Section IV);
- 3 • An overview of the PPA (Section V);
- 4 • An overview of the data center sales contract (Section VI);
- 5 • An assessment of the need for the Project (Section VIII);
- 6 • An evaluation of the Company's economic analysis of the Project (Section IX);
- 7 • Evaluation of NSP's Supplemental Strategist Runs (Section X)
- 8 • My independent economic analysis of the Project (Section XI);
- 9 • An assessment of the projected energy cost savings associated with the Project to
- 10 the Company's North Dakota customers (Section XII);
- 11 • Allocation of generation demand costs (Section XIII);
- 12 • Accounting for fuel and purchase power if the ADP is rejected (Section XIV); and
- 13 • Consideration of additional issues (Section XV).

14
15 **Q. Are you sponsoring any exhibits to your testimony?**

16 **A.** Yes, I am sponsoring three exhibits:

- 17 • Exhibit JAH-1: James Heidell CV
- 18 • Exhibit JAH-2: PA Projected Energy Cost Savings Compared to Market
- 19 • Exhibit JAH-3 PA Projected Cost Savings Including the Google Load

20
21 **II. Summary of Recommendations**

22 **Q. What is your recommendation with regard to approving the Company's**
23 **Application for an ADP to add the proposed Project to Company's integrated**
24 **system?**

25 **A.** My recommendation is that the Commission approve the ADP. It is important to
26 understand that this recommendation is based upon my conclusion that NSP's North
27 Dakota customers are unlikely to receive any significant benefits or harm from the net
28 impact of entering into the Dakota Range III PPA and adding Google's Becker Data

1 Center (Data Center) load. Based upon my analysis, there is a reasonable expectation that
2 the Dakota Range III project would lower average system cost if the impetus for signing
3 the PPA were removed. In other words, if NSP were not adding the Data Center load to
4 its system, which will effectively consume nearly all the energy production from the
5 Project. When I evaluated the cost impact of serving the additional Data Center load, as
6 well as the impact on North Dakota customers' allocation of system energy and capacity
7 costs, my conclusion is that there are unlikely to be any significant cost savings for North
8 Dakota customers.

9 My recommendation is based upon my conclusion that the addition of both the PPA and
10 the Data Center are likely to result in neither significant harm, nor significant benefit to
11 North Dakota ratepayers. My recommendation also factors in the complications that arise
12 with both the exclusion of a new resource as a system resource and the potential issues of
13 evaluating a resource addition in the context of soliciting a major single source load
14 addition. In the hypothetical situation that the additional load was the result of organic
15 load growth and the PPA procurement was not driven by the load, then the addition of the
16 low-cost wind PPA would result in savings to North Dakota customers.

17
18 **Q. If the Commission approves the PPA do you have any recommended conditions on**
19 **the approval?**

20 **A.** Yes, I have two recommendations related to the treatment of the Renewable Energy
21 Credits (RECs). Since NSP is proposing to add the Dakota Range III PPA as a system
22 resource, North Dakota customers should receive financial compensation for its share of
23 the RECs even though NSP will retire all the RECs for the benefit of the Google data
24 center. The second condition is that no cost should be allocated to North Dakota should
25 NSP have to purchase RECs to satisfy its commitments under the contract with Google.

26
27 **Q. What is your recommendation with regard to how to treat Dakota Range III if the**
28 **Commission does not approve the ADP?**

29 **A.** If the Commission does not approve the ADP, my recommendation is to reject NSP's
30 proposed treatment that would mirror the existing approach for accounting for disputed

1 PPA in the Fuel Cost Adjustment (FCA). The current approach used for addressing high
2 cost disputed resources is not applicable in this situation where a low cost resource is
3 being added to serve a discretionary new load. In this case if the cost of the resource is
4 removed then it is also necessary to remove the cost of serving the data center load.
5

6 **II. Summary of Findings**

7
8 **Q. Would you please provide a summary of the findings in your testimony that support**
9 **your recommendation regarding the Commission's treatment of the Application**
10 **and its request for an ADP?**

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

- 14 • The proposed PPA describes the terms and conditions under which the Company
15 will purchase the output of the Project at below market pricing, which is expected
16 to lower NSP's average fuel and purchased power costs compared with the
17 Company's current system.
- 18 • After consideration of wind integration costs and potential curtailments, the PPA
19 is expected to be a lower cost resource compared with the Company making
20 wholesale purchases at Minnesota Hub prices.
- 21 • The PPA does not meet an immediate need for capacity as the first capacity
22 resource added to the system in the reference case is a combustion turbine in
23 2027.
- 24 • As opposed to the PVRR savings of \$22M in the Application, the PVRR will actually
25 increase due to adding the Data Center load.² However, there are potentially small

² Reference Case Savings, Table 2, NSP Application for Advanced Determination of Prudence Docket No. PU-18-430, p 10.

1 savings to North Dakota as a result of the allocation of a small percentage of the
2 system costs.

- 3 • The evaluation of potential savings associated with the Dakota Range III PPA should
4 consider the impact of the Data Center given that the PPA is intended to meet the
5 incremental renewable energy requirements specified in the RESA.
- 6 • There are unlikely to be any significant savings to North Dakota customers after
7 incorporating estimates of the impact of serving the Data Center load, the net impact
8 of the change in system revenue requirements, and the energy and demand costs
9 allocated to North Dakota.
- 10 • If the data center load was part of the base case load forecast, i.e. if the starting load
11 forecast was higher, then the estimated savings from adding the PPA would be similar
12 to the savings put forth in the Company's application which did not consider the data
13 center load.

14 15 **IV. The Impetus for the PPA**

16
17 **Q. Please provide an overview of the Company's Application for the ADP.**

18 **A.** The Company is proposing to execute a twelve-year PPA with Dakota Range III, LLP,
19 the owner of a 151.2 MW wind facility being developed in South Dakota. The project is
20 currently owned by ENGIE IR Holdings, LLC. The Project is expected to be placed into
21 service in 2020 and qualify for one hundred percent of the federal Production Tax Credit
22 (PTC). The Project is co-located with the Dakota Range I and II facilities, which are
23 owned by the Company. The Company will pay a fixed price of **[Trade Secret Begins]**
24 **[REDACTED]** **[Trade Secret Ends]** for electricity from the Project over the twelve-year
25 PPA. The Company's position put forth in the Application is that the Project is justified
26 based upon anticipated energy cost savings even though there is not a near-term need for
27 new generation.

28 The primary impetus for the PPA is the Company's Retail Electric Service Agreement
29 (RESA) with the Data Center to be located adjacent to the Sherco Power plant in Becker,
30 Minnesota. The RESA is complex and the obligations of NSP are a function of the

1 amount of load the Data Center will add to the system. However, at a high level NSP
2 must procure incremental renewable resources to serve the Data Center load. In addition,
3 the near-term expectation is that NSP will be procuring an additional 150 MW of wind to
4 serve the anticipated load of the Data Center in its first ten years of operations.³

5 In the Application, the Company also points to potential benefits to North Dakota
6 resulting from adding a large load in Minnesota that will shift the allocation of power
7 costs based upon the 12 CP method. A significant shortcoming of the Application is that
8 its identified savings analysis does not incorporate the anticipated increased load from the
9 Data Center.

10
11 **Q. Why is it a shortcoming that the Company's ADP Application's analysis does not**
12 **include the Data Center load?**

13 A. While the timing and the precise amount of new load associated with the Data Center is
14 uncertain, it has the potential to be the largest retail customer on the NSP system.⁴ The
15 economic modeling in Strategist incorporated in the Application characterizes the
16 benefits of adding the Dakota Range III PPA without considering Google's Data Center
17 load being added to the system. At a high level, the Strategist modeling of costs captures
18 the benefits from increased market sales and deferring the need for new generation
19 capacity. However, the addition of the Data Center load will result in the acceleration of
20 the need for new capacity; further, during the timeframe of the PPA the amount of
21 surplus energy sales does not increase due to the NSP system load increasing as a result
22 of the Data Center. As I explain later, at the request of Advocacy Staff, the Company
23 developed additional Strategist runs to incorporate the load from the Data Center.

24
25 **Q. Will the Dakota Range III project be used to exclusively serve the Google Data**
26 **Center Load?**

³ NSP issued an RFP on April 10 for another 150 MW with responses due on May 1. (see response to NDPS 1-20)

⁴ PETITION CONTRACTS FOR PROVISION OF ELECTRIC SERVICE TO GOOGLE'S MINNESOTA DATA CENTER PROJECT DOCKET NO. E002/M-19, p 48.

1 A. No, NSP is proposing to treat Dakota Range III as a system resource. The energy and
2 capacity requirements imposed by the Data Center likewise will be served from system
3 resources (including any wholesale market purchases). However, over the life of the
4 initial period of the RESA, conceptually the total load of the Data Center will be met with
5 incremental new renewable resources. The actual matching of Data Center energy
6 consumption and new resource requirements on an annual basis is subject to specific
7 contract terms that are also a function of the Data Center's total load. On an hour by hour
8 basis there is neither an expectation, nor a requirement to match the incremental Data
9 Center load with the production from the incremental renewable energy resources.

10 [Trade Secret Begins]

11 [REDACTED]
12 [REDACTED] [Trade Secret Ends].
13

14 **Q. Is the NDPSC being requested to approve the Google Data Center RESA?**

15 A. No. The Google Data Center RESA is a Minnesota retail load contract under review by
16 the Minnesota Public Utilities Commission (MPUC). NSP is requesting that the MPUC
17 approve three agreements addressing the special rate and the contract terms associated
18 with serving the retail load and recovery of those costs.⁵ My understanding is that the
19 rates charged to retail customers in Minnesota are beyond the jurisdiction of the NDPSC.
20

21 **Q. Is the analysis of the Data Center retail load relevant to North Dakota if it is beyond
22 the jurisdiction of the NDPSC?**

23 A. Yes, it is relevant with regards to understanding the actual expected rate savings
24 associated with Dakota Range III that will be realized by NSP's North Dakota customers
25 after consideration of expected associated new load as well as potential transmission
26 costs.
27

⁵ The MPUC is reviewing a Retail Electric Service Agreement (ESA), a Competitive Rate Response Rider (CRR), and an Interconnection Agreement (IA).

1 **Q. Have you provided an analysis for the Commission which considers the Data Center**
2 **load to be simply additional organic load growth for the Company?**

3 A. Yes. I believe it is appropriate for the Commission to consider the impacts of the Data
4 Center load for reasons discussed earlier in my testimony. However, should the
5 Commission wish to consider the Data Center load to be natural load growth that the
6 Company has an obligation to serve, the analysis in Section XI of my testimony
7 addresses this view and evaluates the economics of the proposed PPA independently of
8 the load addition.

9
10 **V. Summary of Dakota Range III PPA**
11

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

13 A. The PPA for Dakota Range III is a twelve-year contract to sell the entire output to NSP
14 for a fixed price over the contract term. Dakota Range III is responsible for procuring the
15 transmission interconnection as well as responsible for all interconnection costs. The
16 anticipated COD is no later than December 31, 2020. The contract contains provisions for
17 payments from NSP for certain types of curtailments, "Compensable Curtailments."
18 Additionally, NSP has Rights of First Offer should Dakota Range III be offered for sale.

19
20 **Q. What are Compensable Curtailments?**

21 A. Compensable Curtailments under Section 8.3 of the PPA include "economic curtailments
22 and curtailments caused by negative LMP."⁶

23
24 **Q. Has the Company estimated the amount of Compensable Curtailments?**

25 A. No. In the Company's response to Data Request No. NDPSC1-014, the Company
26 indicated that it used a conservative assumption regarding the limits of how much power

⁶ Section 8.3 (B) 1 (ii) Wind Energy Purchase Agreement between Northern States Power Company, a Minnesota Corporation and Dakota Range III, LLC.

1 can be exported based upon transmission constraints. Further, no specific constraints
2 were assigned to the Dakota Range III project in the Strategist modeling. The Company
3 in a separate analysis estimated that the curtailments would start at [Trade Secret
4 Begins...] [REDACTED].⁷ [...Trade Secret Ends]
5 However, I note that the analysis does not distinguish between compensable and non-
6 compensable curtailments.
7

8 **Q. What is the amount paid for a compensable curtailment?**

9 A. NSP's application identifies a price of [Trade Secret Begins...] [REDACTED] [...Trade
10 Secret Ends].⁸
11

12 **Q. Is NSP's agreement with Dakota Range III subject to the approval of the NDPSC?**

13 A. NSP has the right to terminate the PPA if the NDPSC does not approve the requested
14 "Non-Jurisdictional Regulatory Treatment".⁹ The non-jurisdictional treatment refers to
15 the Commission agreeing that the energy and capacity from Dakota Range III will not be
16 used to serve North Dakota customers and the costs will not be charged to, or reimbursed
17 by North Dakota customers.
18

19 **Q. Has NSP requested non-jurisdictional treatment from the NDPSC?**

20 A. NSP in its application has indicated that it is proposing to treat Dakota Range III as a
21 system resource and therefore North Dakota customers would share in the costs and
22 anticipated benefits from the wind project. NSP notes that should the Commission
23 disapprove the ADP then it proposes that it the resource be removed from the FCR. I
24 discuss the proposed treatment, should the Commission reject the ADP, later in my
25 testimony.
26

⁷ NSP response to NDPSC-3-001 Alt A_Model_Reference_Case.

⁸ NSP Application p 8

⁹ NDPSC Data Request No. 1-5 Attachment A p 17 [confidential]

1 **VI. Summary of Data Center Retail Electric Service Agreement**

2
3 **Q. Would you please provide an overview of the Data Center RESA?**

4 A. NSP has negotiated a long-term contract to serve a new Google data center to be built on
5 315 acres of land that is currently part of the Sherco coal plant. (There is a separate
6 agreement to sell some of the Sherco land to Google.) Under the terms of the RESA,
7 NSP will procure incremental renewable resources that on an annual basis produce
8 enough energy to serve the data center. [Trade Secret Begins] [REDACTED]
9 [REDACTED] [Trade Secret Ends] that allow some flexibility in
10 matching the annual incremental renewable energy production with the annual data
11 center loads. The renewable energy credits associated with the incremental renewable
12 resources will be retired for the benefit of Google in the amounts that match the data
13 center load. In addition, depending on the peak load of the data center, there is also a
14 provision for matching the peak demand with the capacity of the incremental renewable
15 resources.
16

17 **Q. What is the term of the RESA?**

18 A. The initial term is ten years with provisions for extension.
19

20 **Q. How does NSP plan to meet the requirement for incremental renewable resources?**

21 A. NSP plans to acquire approximately 300 MW of incremental wind generation to serve the
22 anticipated energy requirements in the first phase of the data center build-out. Dakota
23 Range III is the first phase of that procurement.
24

25 **Q. Does the Google RESA have specific commitments with regard to its contracted
26 demand or minimum energy requirements?**

27 A. No. There are confidential load forecasts as well as an expected capacity factor associated
28 with the load but no specific load commitments. Given that the pattern of the load growth
29 is uncertain, there is also some flexibility built into the contract regarding the timing for
30 meeting the annual energy requirements with incremental renewable resources.

1
2 **Q. Will NSP have to build new transmission facilities to serve the Data Center?**

3 A. Yes. The Data Center will be served at transmission level voltage and NSP will be
4 responsible for the costs associated with constructing a substation and transmission that
5 will connect with the Data Center. NSP has developed estimates for these costs separated
6 into four phases where each phase is associated with increments in the Data Center's
7 peak demand. The first phase is anticipated to meet the load requirements in the initial
8 term of the RESA.

9
10 **Q. Will North Dakota customers be responsible for the recovery of a share of the cost
11 of the new transmission facilities?**

12 A. Potentially. Based upon the Company's response to Data Response NDPSC 2-4, any
13 costs that are defined as network costs will be proportionately allocated to North Dakota.
14

15 **Q. Will North Dakota customers benefit from the sale of Sherco land to Google?**

16 A. Potentially. NSP has noted that they anticipate a gain on the land sale, but has not
17 provided any additional detail on this point.
18

19 **Q. Is the RESA conditioned on approval of the NDPSC?**

20 A. Article 6-3 of the RESA addresses termination for failure of regulatory approvals
21 including the NDPSC. My non-legal interpretation is that the Company would have the
22 right to terminate if it did not get approval from the NDPSC or approval with
23 substantially equivalent economic terms. However, the Company may choose to waive
24 those requirements.
25

26 **VII. Evaluation of the ADP Application**
27

28 **Q. Please provide an overview of your analysis of the ADP application?**

1 A. My assessment of the Project addresses three fundamental questions:

- 2 • First, is there a need for the project with regard to serving NSP's load?
- 3 • Second, will the project lower energy and capacity costs for NSP's North Dakota
- 4 customers?
- 5 • Third, what are the impacts of adding the data center load on the allocation of
- 6 fixed generation costs using the 12CP methodology?
- 7

8 The analysis of whether the Project will lower energy and capacity costs is further
9 divided into two scenarios:

- 10 1) The economics of Dakota Range III without incorporating the estimated data
- 11 center load; and
- 12 2) The economics of Dakota Range III incorporating the estimated data center
- 13 load.
- 14
- 15

16 **Q. How did you frame the analysis of Dakota Range III with the expected Data Center**
17 **load?**

18 A. The Data Center's initial load and its growth are uncertain, so it was necessary to make
19 associated assumptions about both. In addition, I incorporated an adjustment; while the
20 ADP request is specifically related to the Dakota Range III project, the Company is
21 expecting to add an additional approximately 150 MW of wind to meet the RESA terms
22 of securing incremental renewable generation to serve the data center in the initial term of
23 the RESA.

24
25 **Q. What did you assume for the Data Center load in your analysis?**

26 A. NSP estimates that over the initial ten-year term of the contract the Data Center load will
27 be [Trade Secret Begins...] [REDACTED] [...Trade Secret Ends] load factor.
28 Based upon scenarios that the Company developed in conjunction with its Minnesota
29 PUC filings, I concluded that a reasonable base case assumption is that the load starts at
30 [Trade Secret Begins...] [REDACTED]
31 [REDACTED] [...Trade Secret Ends] Because the company is targeting approximately

1 150 MW of additional wind, I assumed that the Data Center load that would be served by
2 the Project would be [Trade Secret Begins...] [REDACTED]
3 [REDACTED]. [...Trade Secret Ends]
4

5 **Q. Would you please explain the assumed relationship between the amount of wind**
6 **energy acquired and the Data Center load?**

7 **A.** The Dakota Range III project has an expected capacity factor of [Trade Secret Begins...]
8 [REDACTED] [...Trade
9 Secret Ends] NSP is required to procure incremental renewable generation to meet the
10 Data Center load. At the Data Center's expected load factor, [Trade Secret Begins...] [REDACTED]
11 [REDACTED] [...Trade Secret Ends] load translates into an annual energy usage of [Trade
12 Secret Begins...] [REDACTED]
13 [REDACTED]
14 [REDACTED]
15 [REDACTED] [...Trade Secret Ends]
16

17 **Q. Would you please explain the assumed relationship between the amount of**
18 **accredited capacity acquired from Dakota Range III and the data center load?**

19 **A.** The Dakota Range III project has a nameplate capacity of 151.2 MW. However, the
20 MISO accredited capacity is expected to be approximately 22.9 MW. Based upon the
21 previously discussed assumed data center load, I estimate that by the end of year [Trade
22 Secret Begins...] [REDACTED] [...Trade Secret Ends] there is an incremental capacity
23 requirement up to a total capacity of [Trade Secret Begins...] [REDACTED] [...Trade Secret
24 Ends] at the end of year ten. The result is that the Data Center creates an incremental
25 system capacity requirement.
26

27 **VIII. Need Assessment of the Project**

28

29 **Q. Does the Company need the Project to meet its capacity requirements?**

1 A. The Company does not project an immediate capacity need. In the Company's Strategist
2 base case load forecast, which does not consider the additional Google Data Center load,
3 new capacity resources are not added to the system until 2027 when the model adds a 374
4 MW combustion turbine in addition to a combined cycle project. The Dakota Range III
5 defers the need for the 374 MW CT until 2030 to 2031.¹⁰
6

7 **Q. Why should the Commission grant an ADP for the project?**

8 A. The Project is expected to lower the Company's system average cost, consequentially the
9 Project is considered "least cost".
10

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

13 A. The project is not expected to significantly change the Company's capacity mix. The
14 Dakota Range III project is expected to add approximately 22.9 MW of accredited
15 capacity.¹¹
16

17 **Q. How does the proposed Project impact the Company's energy mix from a resource
18 diversity perspective?**

19 A. The Company's Strategist analysis base case includes the recently approved 1,550 MW
20 of wind plus the Dakota Range I & II projects. As shown in the following tables, the
21 Dakota Range III project does not significantly change the generation mix.
22

¹⁰ Attachment A, PU-18-430 NDPSC 1-011.

¹¹ NSP Response to NDPSC-02-006.

1 **Table 1: GWH Resource Mix* without Dakota Range III**

Resource Type	2019	2020	2022	2025	2030
Coal	32%	26%	19%	16%	10%
Nuclear	27%	25%	18%	18%	17%
Gas	13%	14%	10%	11%	10%
Hydro	5%	4%	3%	4%	4%
Wind / Solar	22%	30%	49%	52%	59%
Other	2%	2%	1%	1%	0%

2 * Table excludes system purchases

3
4 **Table 2: GWH Resource Mix* with Dakota Range III**

Resource Type	2019	2020	2022	2025	2030
Coal	32%	26%	18%	15%	9%
Nuclear	27%	25%	18%	17%	17%
Gas	13%	14%	10%	10%	10%
Hydro	5%	4%	3%	3%	4%
Wind / Solar	22%	30%	50%	53%	59%
Other	2%	1%	1%	1%	0%

5 * Table excludes system purchases

6
7 **IX. Evaluation of the Company's Economic Analysis of the Project**

8
9 **Q. How did the Company evaluate the proposed Project's impacts on its system costs?**

10 **A.** The Company conducted planning studies using the Strategist resource planning model to
11 evaluate the projected impact on its system costs. In projecting the economic dispatch of
12 each NSP resource, Strategist simulates the operation of the NSP System and estimates
13 the total system costs impact of the Project on a present value basis.

14
15 **Q. Do you believe that Strategist is limited in its ability to accurately evaluate the
16 economics of adding wind generation to the Company's system?**

17 **A.** Yes. Strategist has limitations, particularly with respect to the evaluation of wind and
18 solar resources. However, even while acknowledging Strategist's shortcomings in
19 accurately representing both system load and intermittent generation facilities, the
20 Company's analysis demonstrates that the proposed Project will provide savings for the

1 Company's customers, absent consideration of the Data Center load.
2

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

4 A. Yes. Specifically, I reviewed the following:

- 5 • The natural gas and wholesale electric market price assumptions used in the
6 model; and
- 7 • The results of the planning scenarios the Company conducted via Strategist.
8

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

11 A. Yes. The Company developed scenarios designed to evaluate the sensitivity of the Project
12 and its impact on the Company's system to varying assumptions such as high and low
13 system loads and natural gas prices. Because power prices and natural gas prices are
14 highly correlated in the MISO market, the natural gas sensitivities also incorporated
15 higher and lower market prices.
16

17 Additionally, the Company evaluated three different energy markets-based scenarios:
18

- 19 1) The Base or Reference case "Markets On" scenario assumed that the
20 Company does and will continue to make daily sales and purchases to and
21 from the MISO market;
- 22 2) The "Markets Off, no dump energy credit" scenario assumed that the
23 Company *does not* make daily sales and purchases to and from the MISO
24 market, and no value is given to any generation in excess of the Company's
25 load requirements; and
- 26 3) The "Markets Off, dump energy credit" scenario assumed that the Company
27 *does not* make daily sales and purchases to and from the MISO market, and
28 any generation in excess of the Company's load requirements is valued at half
29 of the projected market energy price.

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26

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

A. No. The Markets Off scenarios assume the Company does not have access to buy and sell power in the MISO market. This does not reflect reality as the Company buys and sells power in the MISO market every day. My understanding is that the Markets Off scenarios were developed for the MPUC.

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

A. No. The market prices are an exogenous input to Strategist; the market prices used by the Company are inputs to the model.

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

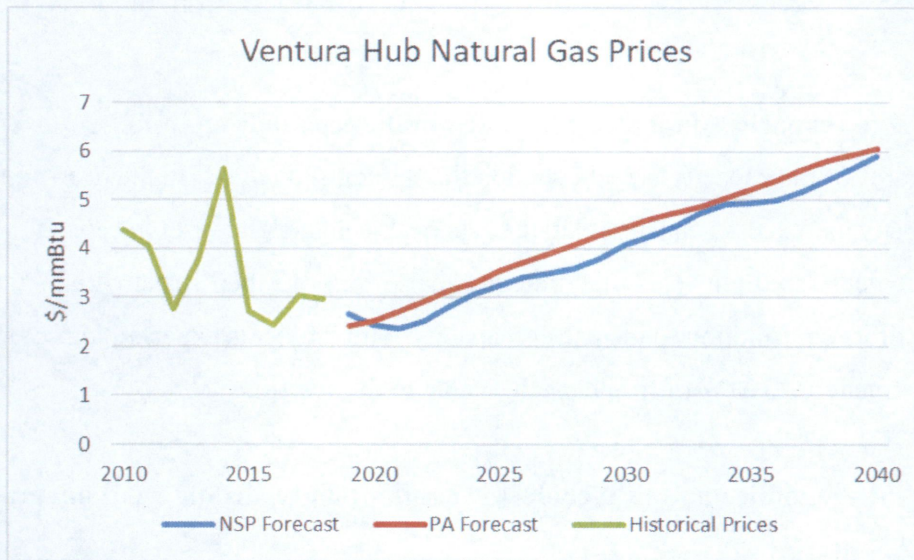
A. Yes. When natural gas-fired generation units are the marginal units setting market prices, there is a strong relationship between gas prices and power prices. The MISO Market Monitor reports that over the last 13 months, the correlation coefficient between the Henry Hub natural gas price and the MISO Real Time Locational Marginal Price was 0.84.¹²

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

¹² MISO May 2018 Monthly Market Assessment Report, Market Evaluation and Design, July 12, 2018, p 16.

1 A. The natural gas price forecast appears reasonable. I compared the Company's delivered
2 natural gas price forecast for the Ventura pricing hub in Minnesota with that of PA's
3 forecast for the hub. The Company's forecast is generally slightly lower than PA's
4 forecast, which would tend to slightly decrease the associated market prices and projected
5 benefits of the Project.

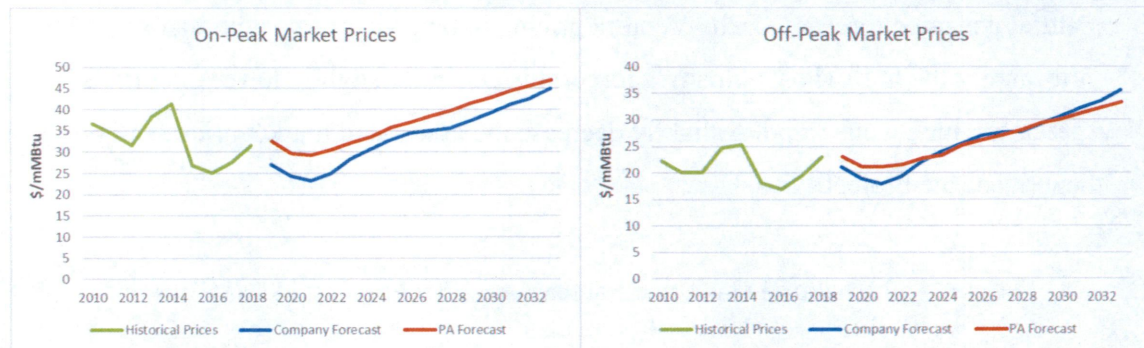
6
7 **Figure 1. PA Natural Gas Price Forecast vs. NSP Forecast (\$/MMBtu)**



8
9
10 **Q. How does the Company's forecast of MISO power prices compare to PA's forecast?**

11 A. The Company's MISO power prices forecast generally follows the same trend as PA's
12 and is slightly lower than PA's forecast over the PPA term, as shown in Figure 2 below. I
13 find the Company's forecast to be reasonable and I would expect that the Company's
14 Strategist results are a reasonable projection of the Project's value to the NSP system.

1 **Figure 2. MIN HUB Historical and Forecast Prices (\$/MWh)**



2
3
4 **Q. How is the capacity of the Project valued in the economic analysis?**

5 **A.** The value of the capacity is embedded in the Strategist analysis. In the near-term, the
6 Company has excess capacity relative to its peak demand and reserve capacity
7 requirements. In these years the Strategist analysis credits the Project with incremental
8 value of its contribution to the excess capacity. The Project is expected to provide
9 approximately 23 MW of firm capacity value to the system.

10
11 **Q. Does the economic analysis include any assumption regarding wind integration
12 costs?**

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

18
19 **Q. What did you conclude regarding the Company's economic analysis of the Project?**

20 **A.** I concluded that the Company's Strategist analysis was reasonably conducted. While I
21 did not conduct a parallel Strategist analysis, I conducted a thorough review of the
22 Company's analysis and found the input assumptions and output results to be reasonable.

23
24 However, as noted throughout my testimony, I believe that the Company's initial

1 Strategist analysis as described in the Application portrays an incomplete picture of the
2 economics of the Project. I believe that only by considering both the Project as well as
3 the Data Center RESA can the Commission get a complete understanding of the impacts
4 of the Project on North Dakota ratepayers.
5

6 **X. Evaluation of NSP's Supplemental Strategist Runs**

7 **Q. Did Advocacy Staff request NSP to develop additional Strategist model runs?**

8 A. Yes, the Company's Strategist modeling and different scenarios included in the ADP
9 Application and associated direct testimony evaluated the savings of the PPA while
10 excluding the anticipated Data Center load. For example, the only difference between the
11 reference case run and the reference case with the PPA run is the inclusion of the PPA.
12 Even in the high load case, the load is the same with, and without the PPA. Advocacy
13 Staff in Data Request NDPSC 2-008 requested that the Company develop new model
14 runs in which the cases with the PPA also include a commensurate amount of load
15 associated with the Data Center.
16

17 **Q. Did NSP change any other assumptions besides adding the incremental load?**

18 A. Yes. In the Supplemental analysis, the Company and Advocacy Staff agreed that it was
19 appropriate to increase the transfer capacity out of MISO Zone 1 from 1,350 MW to
20 1,800 MW based upon the Company's analysis that the transfer capacity used in the
21 initial runs was overly conservative given anticipated transmission system enhancements.
22 The impact of increasing the transfer capacity is to reduce the amount of dump energy in
23 the model and allow more generation to be sold into the market. One consequence of this
24 change is that the reference case (no PPA) used in the response to Data Request NDPSC
25 2-008 is different than the reference case in the pre-filed direct testimony.
26

27 **Q. Did adding the Data Center load accelerate the NSP system need for capacity?**

1 A. Yes, the combined impact of adding the PPA and the data center load accelerated the
2 need to add one 331 MW CT from 2030 to 2028.¹³
3

4 **Q. What are the economic results of the Company's Supplemental analysis?**

5 A. The results of the analysis were that when including both the PPA and the Data Center
6 load, the system PVRR increased but that there was still a PVRR [Trade Secret
7 Begins...] [REDACTED] [...Trade Secret Ends] savings to NSP's North Dakota customers as a
8 result of changes to the capacity allocation factor associated with adding more load to
9 Minnesota.¹⁴
10

11 **Q. Do you agree that revised estimated savings to North Dakota are reasonable?**

12 A. Yes, I think the estimated savings are reasonable. However, I made an adjustment to the
13 logic of how NSP allocated costs to North Dakota and that adjustment lowers the savings
14 further. I did not complete a detailed review of the Strategist modeling but based upon a
15 simplified model that I developed, my conclusion is that the Company conducted the
16 modeling correctly. My concern is that the calculation of the savings is based upon
17 allocating the annual value of the revenue requirement calculated in Strategist in each
18 year based upon the assumed 12 CP capacity allocation factor. My concern is that only
19 generation demand related costs should be allocated on the 12CP capacity allocation
20 factor, while the fuel and purchased power costs should be allocated on a loss adjusted
21 energy sales allocation factor. I did not have information on how to divide the annual
22 revenue requirement from Strategist into energy and demand. Therefore, I used FCA
23 filings to estimate an energy allocation factor and a percentage of the total Strategist
24 PVRR that should be allocated on energy and the percentage that should be allocated on
25 demand. Based upon this adjustment, the resulting savings to NSP's North Dakota
26 customers is [Trade Secret Begins...] [REDACTED] [...Trade Secret Ends] depending

¹³ NSP Public Response to NDPSC 2-008.

¹⁴ NSP confidential response to NDPSC-2-008.

1 on the assumption of how often there are rate cases that will cause the demand allocation
2 factor to be updated. My calculations are provided in Exhibit JAH-3.
3

4 **Q. Do you have any other concerns with estimating the savings based upon a capacity**
5 **allocation factor?**

6 A. Yes, my understanding is that the capacity allocation factor is used to allocate generation
7 demand costs in conjunction with general rate cases. The factor is not updated or used in
8 the FCA. The Company's estimated savings assumes that the capacity allocation factor
9 changes every year. In the Company's model, the North Dakota jurisdiction's share of
10 costs decreases each year due to the assumptions surrounding the data center's load
11 growth. For example, if the Company had a rate case in 2023 for rates in 2024 but then
12 did not have a rate case until 2030, those six years of Minnesota load growth would not
13 result in any associated reduction in the non-fuel and purchased power costs allocated to
14 North Dakota via the 12CP capacity allocation factor.
15

16 **Q. Based upon your evaluation of the NSP analysis, do you conclude that there will be**
17 **material savings to North Dakota customers after accounting for the RESA?**

18 A. No, the identified savings are not material given the inherent uncertainties in any long-
19 term forecasts and also giving consideration for the risk of curtailment or payments by
20 the Company for compensable curtailments.¹⁵ There are also other potential costs
21 including procurement of any shortfall of RECs needed to meet the Data Center load,
22 lower wind energy production as a result of outages or environmental conditions, and any
23 increases in transmission costs allocated to North Dakota as a result of any of the
24 transmission improvements associated with serving the Data Center being classified as
25 network resources.
26
27

¹⁵ NSP response to NDPSC-1-014 (c)

1 **XI. Independent Economic Analysis of the Project**
2

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

4 A. Yes. While the Company's Strategist analysis sought to evaluate the Project as a resource
5 integrated into the NSP system, I took an alternate approach to evaluate the project as a
6 MISO energy market participant.
7

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

9 A. Yes. Using the Aurora XMP hourly chronological dispatch model, PA developed a long-
10 term forecast of monthly on- and off-peak MN Hub prices. I used those prices in
11 conjunction with the hourly wind production profile to estimate the revenues that the
12 Company will receive from dispatching the Dakota Range III project into the MISO
13 market. I compared the estimated revenues with the Project's PPA costs and additional
14 costs related to Compensable Curtailment and wind integration costs.
15

16 **Q. Did you evaluate the impact of changes in production resulting from curtailment or**
17 **deviations from expected performance?**

18 A. Yes. The Company indicated expected curtailments of approximately [Trade Secret
19 Begins] [REDACTED]
20 [REDACTED] [Trade Secret Ends] Further, the Company indicated
21 that the price of these curtailments was approximately [Trade Secret Begins] [REDACTED]
22 [Trade Secret Ends]. My analysis incorporated these curtailment costs.
23

24 **Q. Does your economic analysis consider any other costs of the Project, such as wind**
25 **integration, wind congestion, or wind-induced coal plant cycling costs?**

26 A. Yes. In the Company's Application, Mr. Martin's testimony provided assumptions which
27 were incorporated into the Company's analysis related to wind integration and wind
28 congestion costs. My analysis incorporated these assumptions.
29

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

3 **A.** No, neither environmental nor economic development benefits are incorporated into the
4 estimated ratepayer savings to ratepayers.

5
6 **Q. Did you conduct any scenario or other sensitivity analyses of the Project?**

7 **A.** Yes. In addition to my base case analysis, I also conducted a similar analysis which
8 assumed that the MISO market experiences a significant increase in renewable
9 generation.

10
11 **Q. On what did you base your assumptions for this High Renewables scenario?**

12 **A.** I based the increased renewable generation levels in MISO upon the MISO Transmission
13 Expansion Plan (MTEP) Futures planning process. The MTEP20 Futures are currently
14 under development by the MTEP Planning Advisory Committee. Based on an April 2019
15 planning document, I created the High Renewables scenario by assuming that MISO
16 renewables reach the minimum renewable penetration levels (40%) associated with the
17 most aggressive MTEP20 Futures case, the Accelerated Fleet Change case.

18
19 In simple terms, what this means is that my High Renewables scenario assumes that
20 MISO as a whole reaches a minimum of approximately 40% renewable generation by
21 2033. In the case of the Company's MISO Zone 1, this resulted in the High Renewables
22 scenario assuming that Zone 1 reaches approximately 75% renewable generation within
23 fifteen years.

24
25 **Q. Why do you think this scenario is relevant for the Commission to consider?**

26 **A.** I have concerns that while the proposed PPA's pricing terms are attractive to the
27 Company when compared to today's market prices, it's possible that as additional low-
28 cost renewables are added to the MISO system, market prices will likely become
29 depressed, which would reduce the potential savings associated with the Project. To
30 evaluate this possible "downside" case, I created the High Renewables scenario.

1
2 **XII. Assessment of the Projected Energy Cost Savings of the Project**
3

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

6 **A.** Yes, Table 3 below summarizes my comparison. The Company's Strategist analysis of
7 the Project as an integrated NSP system resource (excluding considerations of the costs to
8 serve the data center's load, as described above) estimates approximately \$22M in
9 present value, total system cost savings. My independent analysis of the Project estimates
10 approximately \$48M in present value total system cost savings under base case market
11 conditions. When considering the potential for significantly higher renewable generation
12 in MISO, my analysis indicates the potential present value total system cost savings are
13 reduced to approximately \$31M. Annual savings are provided in Exhibit JAH-2.
14

15 **Table 3. Independent Economic Analysis Results**

	NSP Strategist Analysis	PA Base Case Analysis	PA High Renewables Analysis
Present Value System Cost Savings (\$M)	22	48	31

16
17 **Q. What are your conclusions with regard to the Company's estimate of \$22 million of**
18 **system cost savings from the Project?**

19 **A.** My conclusion is that the Project is likely to result in electricity cost savings to North
20 Dakota customers absent consideration of the data center load. Given the uncertainties
21 inherent in modeling electric systems, I find the variance between the Company's
22 analysis and my base case independent analysis conclusion of \$48 million in present
23 value total system cost savings to be reasonable, and both indicate the likelihood of
24 system cost savings for NSP customers.
25

26 Comparing my High Renewables scenario results of approximately \$31 million of
27 present value total system cost savings to my estimated base case present value of savings

1 of approximately \$48 million in savings, I find that it's reasonable to expect a significant
2 reduction in estimated savings due to market prices being depressed due to the high
3 penetration of lower cost renewables which were assumed in the scenario.
4

5 As discussed above, the Commission's consideration of the ADP Application should
6 consider not only the economic benefits of the Project itself, but the wider implications of
7 the Project and the Data Center RESA in combination.
8

9 **Q. How would North Dakota customers be impacted by the Project in the hypothetical**
10 **case that the Data Center was not considered a discrete customer addition by the**
11 **Company, but rather be considered as a normal load growth?**

12 A. This hypothetical case is addressed in the analysis presented in Section XI of my
13 testimony. Section XI evaluates the Project as purely a market participant without
14 considering any Minnesota or North Dakota loads. In the hypothetical case, the Data
15 Center load would be not considered in the Commission's evaluation, and the impact of
16 the Project would be irrespective of the load. This is essentially the same analysis as if
17 the Project were purely a market participant.
18

19 **XIII. Allocation of Generation Demand Costs** 20

21 **Q. Have you evaluated NSP's finding that North Dakota customers will benefit in the**
22 **allocation of generation demand costs as a result of adding the Data Center load?**

23 A. Yes. In Table 3 of Mr. Martin's testimony, he presented an analysis illustrating how
24 adding the data center load changes the 12 CP demand cost allocation factor, which
25 would result in shifting a greater parentage of generation costs classified as demand to
26 Minnesota.
27

28 **Q. Do you expect that there will be demand cost savings for North Dakota's customers**
29 **based upon your review of Mr. Martin's analysis?**

1 A. I anticipate that there will be minimal savings in the early years of the contract. However,
2 I do not expect that there will be savings after the first few years depending on the load
3 growth of the Data Center. In addition, the demand cost allocation will not change until
4 the next general rate case in North Dakota. Finally, I note that the use of the 12CP
5 allocation factor was an issue in the past general rate case, and the settlement in that rate
6 case Advocacy Staff agreed to support the 12CP through 2025. In any general rate case
7 after 2025, the demand cost allocator might be revised and therefore the benefits
8 attributable to North Dakota customers of adding the data center would also be revised at
9 that point.
10

11 **Q. Why are you not anticipating demand cost savings after the first few years?**

12 A. After the first few years I expect that the demand cost allocation factor would continue to
13 decrease the percentage of the generation demand costs allocated to North Dakota.
14 However, after the first few years the amount of demand costs will increase as the peak
15 load of the data center exceeds the accredited capacity of Dakota Range III. This should
16 result in either less surplus capacity to sell in the earlier years and in the later years
17 accelerating the need for a new combustion turbine.
18

19 **XIV. Accounting for Fuel & Purchase Power Cost if ADP is**
20 **Rejected**
21

22 **Q. Would you please summarize the Company's proposal for addressing the costs of**
23 **Dakota Range III if the Commission rejects the ADP?**

24 A. The Company proposes a treatment like the precedent for treating other historical
25 disputed PPAs. This treatment involves removing the cost of the PPA from the power
26 cost for the Fuel Cost Rider (FCR) period and replacing that cost with an equivalent
27 amount of energy purchased at the average system cost.
28

1 **Q. Do you recommend that the Commission adopt the Company's proposed treatment**
2 **should the ADP be rejected?**

3 A. No. The precedent was designed, in part, to address the Company's signing PPAs for
4 expensive renewable resources that would raise the average fuel and purchased power
5 costs. The treatment protected NSP's North Dakota customers from paying higher power
6 costs driven by resource procurement policies in other states. Based upon my analysis,
7 my conclusion is that substituting average power costs for the Dakota Range III project
8 would result in increasing the average fuel and purchased power costs for North Dakota.
9 My recommendation is that the Commission consider an alternative approach given that
10 although NSP is proposing to treat Dakota Range III as a system resource, it is being
11 acquired to serve the Google RESA.

12
13 **Q. What is your proposed alternative approach?**

14 A. My proposal is to not only remove the PPA from the fuel and purchased power, but also
15 remove the load of the data center in the calculation of average system fuel and
16 purchased power costs.

17
18 **Q. What is your rationale for incorporating the data center load in the FCR if the ADP**
19 **is rejected?**

20 A. I consider the data center load to be discretionary and an integral part of the decision to
21 execute the PPA for Dakota Range III. Based upon my review of the Google RESA and
22 the filing in Minnesota requesting approval of three agreements related to the Google
23 retail load, I have concluded that Minnesota and NSP actively sought to attract the data
24 center load and offer special pricing to attract the load. From the Minnesota perspective
25 there appear to be benefits to Minnesota in the form of economic development and
26 obtaining marginal revenues for Minnesota NSP customers that exceed the marginal costs
27 of the electric service. However, North Dakota does not directly share in those economic
28 development benefits or the increased retail revenues.

1 **Q. Do you have an alternative proposal for addressing Dakota Range III in the FCR if**
2 **the ADP is rejected?**

3 A. Yes. However, I recognize that there are numerous potential approaches and that this
4 proceeding may not be the appropriate place to address the issue. One approach is to
5 exclude both the data center load and the PPAs secured to serve the data center load. This
6 would be done in a three-step process that I would expect to be reasonable to implement.

7
8 The first step is to remove the cost of the PPA from NSP's fuel and purchased power
9 costs. This is the same first step used to address the disputed PPAs. The second step is to
10 remove the marginal benefits and costs associated with the PPA from the total remaining
11 power costs. The marginal cost and benefits are calculated based upon the hourly
12 production from the Project and the hourly load of the Data Center. Energy from the
13 Project is sold to the market, resulting in extra power sales revenues that would not have
14 occurred but for signing the PPA and the Google RESA.

15
16 Similarly, the cost of serving the Data Center's load is based upon purchases from the
17 MISO market, resulting in incremental costs that would not have been incurred but for
18 the PPA and the RESA. Sales should be valued at the Dakota Range III's hourly nodal
19 price and Purchases to serve the load should be valued at the Minnesota Hub price. The
20 hourly sales and costs would be summed over the FCR period. If the total is positive net
21 benefits, that cost would be added to the adjusted total costs calculated in the first step.
22 The benefits would be removed since North Dakota would not get a share of the benefits
23 having rejected the ADP. Likewise, if the total is negative net costs, those costs would
24 be subtracted from the adjusted total costs so that North Dakota is not penalized for the
25 added system costs of serving the data center.

26 The third step is to remove the data center load from the total sales to calculate the
27 adjusted average power costs for the FCR period, which would be compared with the
28 average cost recovered in rates in order to calculate the appropriate FCR adjustment.
29

1 **Q. Would your proposal always result in lowering the energy and fuel costs allocated to**
2 **North Dakota?**

3 A. No. In the early years when the electricity purchased under the PPA is significantly
4 greater than the data center load, there is likely to be a net reduction in average power
5 costs and North Dakota would not share in that benefit. In later years, when the load of
6 the data center exceeds the power produced by the Project there would be a reduction in
7 the average power costs. The amount of the adjustment is a function of both the Data
8 Center loads and the difference between the PPA and Minnesota Hub prices.
9

10 **XV. Other Considerations**
11

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

14 A. Yes. I have comments related to:

- 15 • The relationship of the procurement of the Dakota Range III PPA and the
16 Company's Integrated Resource Plan (IRP);
- 17 • Consideration of what happens after the end of the PPA and the initial term of the
18 Google RESA; and
- 19 • Treatment of the renewable energy credits (RECs).
20

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

22 A. I understand that there is a timing issue. If one evaluates the Application and the PPA as
23 filed, the justification is to lower power costs, as opposed to being procured to meet the
24 requirements of the contract with Google. From this perspective the Commission is being
25 asked to make a resource procurement decision prior to reviewing the Company's IRP
26 and its associated long-term resource procurement plan that is expected in the summer of
27 2019.
28

1 **Q. Do you anticipate that the PPA will be found to be cost effective in the 2019 NSP**
2 **IRP?**

3 **A.** Yes, the PPA is a low-cost wind resource relative to the Company's current system.
4 However, the relative savings compared to market purchases may be lower than
5 forecasted based upon factoring in potential regional procurement policies that may be
6 reflected in the IRP, such as Minnesota moving to 100% renewables by 2050 or Xcel's
7 goal to have carbon emissions 80% below its 2005 level by 2030.¹⁶
8

9 **Q. What are the cost implications of serving the Data Center after the termination of**
10 **the PPA?**

11 **A.** The PPA has a term of twelve years and NSP has negotiated a ten-year rate for the Data
12 Center (subject to MPUC approval). However, at the end of the ten-year rate agreement,
13 NSP will have an obligation to serve the anticipated growing load of the Data Center at a
14 rate subject to negotiation and MPUC approval.¹⁷¹⁸ While the NDPSC is not involved in
15 the retail rate, the impact on serving the Data Center load beyond the term of the PPA
16 was not modeled or analyzed in this proceeding. The Data Center load in NSP's high
17 growth rate starts at [Trade Secret Begins] [REDACTED] [Trade Secret Ends] in year ten
18 and could grow from there. The Data Center load, the cost of serving the load after the
19 ten-year extension, and the total system loads represent significant unknowns. It is
20 difficult to draw a conclusion regarding the long-term impacts of the Data Center on
21 North Dakota power costs. However, the Commission should be aware that there are
22 long-term implications arising from its decision on whether or not the PPA and the data
23 center are treated as non-jurisdictional.
24

25 **Q. What are your concerns regarding the RECs?**

¹⁶ Building a Carbon-Free Future, Xcel Energy Carbon Report 2019.

¹⁷ NSP Petition Contracts for Provision of Electric Service to Google's Minnesota Data Center Project
Docket No. E002/m-19-___, p 20.

¹⁸ The Retail Electric Service Agreement states that negotiations to extend the initial ten-year contract term
will include the principles of recognition of the customer's investment in the Data Center and the Company's
obligation to serve. Section 3.2 Good Faith Negotiations for Extension, December 12, 2018.

1 A. I have two concerns. First NSP is requesting that the PPA is treated as a system resource.
2 However, the Company's proposal does not share the benefits of the RECs in a manner
3 comparable to other renewable resources included in the FCA. The second concern is the
4 potential liability if the PPA does not produce enough credits to meet the data center load.
5

6 **Q. Why is the Company's proposed treatment of the RECs inconsistent with other
7 renewable resources?**

8 A. The Company is proposing to retire all the RECs for the benefit of Google as opposed to
9 the current precedent of allocating a proportional share of the RECs to North Dakota
10 based upon the North Dakota load. Consequentially, my recommendation is that if the
11 Commission approve the ADP, that it requires the Company to credit North Dakota with
12 the monetized value of the North Dakota's share of the RECs.
13

14 **Q. What is your recommendation regarding the treatment of any RECs that the
15 Company may need to purchase to meet its obligations to Google?**

16 A. My recommendation is that should the Company have to purchase RECs due to having
17 insufficient incremental renewable generation to serve the entire data center load, that
18 none of those costs are allocated to North Dakota.
19

20 **Q. Does this conclude your testimony?**

21 A. Yes.

Example Pre-filed Testimony – Joel Jeanson

DIRECT TESTIMONY AND SCHEDULES

JOEL F. JEANSON

STATE OF NORTH DAKOTA
BEFORE THE
NORTH DAKOTA PUBLIC SERVICE COMMISSION

NORTHERN STATES POWER COMPANY
ADVANCE PRUDENCE – BIOMASS PPAS
APPLICATION FOR DEFERRED ACCOUNTING

CASE NOS. PU-17-322,
PU-17-270, PU-17-271

- 45 PU-17-322 Filed 02/02/2018 Pages: 22
Exhibit PSC-1 - Direct Testimony of Joel Jeanson
Public Service Commission
- 51 PU-17-271 Filed 02/02/2018 Pages: 22
Exhibit PSC-1 - Direct Testimony of Joel Jeanson
Public Service Commission
- 51 PU-17-270 Filed 02/02/2018 Pages: 22
Exhibit PSC-1 - Direct Testimony of Joel Jeanson
Public Service Commission

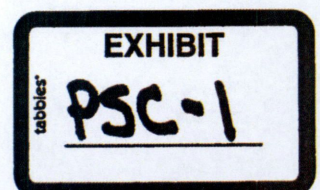


TABLE OF CONTENTS

I. Introduction and Qualifications3

II. North Dakota Legislative Statutes and Administrative Code5

III. Industry Standards and Practices6

IV. Summary of NSP Request9

V. Assessment of the NSP Requests for Deferred Accounting Treatment12

VI. Recommendations16

1 **I. Introduction and Qualifications**

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

3 **A.** My name is Joel F. Jeanson. I am a Principal Consultant at PA Consulting Group
4 (PA). My business address is 1611 North Kent Street, Suite 301, Arlington, VA
5 22209.

6
7 **Q. On whose behalf are you filing this testimony?**

8 **A.** I am filing this testimony on behalf of the Advocacy Staff of the North Dakota Public
9 Service Commission (Commission or NDPSC).

10
11 **Q. Please summarize your qualifications and experience.**

12 **A.** I have worked in the utility industry for the past 38 years, primarily specializing in
13 regulatory finance and accounting issues. I started my professional career in the audit
14 division for a Big Eight accounting firm, working primarily with investor-owned
15 utility clients. After leaving public accounting I went to work for a large Midwest
16 utility in a variety of accounting, planning/budgeting, corporate performance, and
17 auditing roles. Since 2001, I have worked as a consultant to clients in the utility and
18 energy industry, including regulators, utility management, and investors. My
19 academic background includes a B.S. in Business (with distinction) from Indiana
20 University. I am a Certified Public Accountant (inactive). My CV is provided in
21 Exhibit JFJ-1.

22
23 **Q. Have you testified before the North Dakota Public Service Commission
24 previously?**

25 **A.** No.

26
27 **Q. What is the purpose of your testimony?**

28 **A.** The purpose of my testimony is to provide the Commission with an assessment of the
29 Northern States Power Company – Minnesota (NSP or the Company) request for

1 deferred accounting for the Benson Power LLC facility purchase and the Power
2 Purchase Agreement buyouts for the Pine Bend and Laurentian Energy projects.
3 NSP has requested deferred accounting treatment including a return on the regulatory
4 assets associated with:

- 5 • The termination of the PPA for Laurentian biomass project,
- 6 • The termination of the PPA for the Pine Bend biomass project, and
- 7 • The purchase and shut down of the Benson biomass project.

8 I have reviewed the Application, supporting direct testimony, and responses to
9 interrogatories in order to develop recommendations regarding the use of deferred
10 accounting treatment for these projects and whether any conditions should be put on
11 an approval of the request for deferred accounting.

12
13 **Q. Would you please summarize the organization of your testimony?**

14 **A.** Yes. My testimony is organized as follows:

- 15 • Relevant North Dakota legislative statutes and administrative code.
- 16 • Industry standards and practices related to deferred accounting.
- 17 • ND PSC orders to identify precedent-setting criteria used by the Commission.
- 18 • Criteria I believe to be appropriate given industry standards and practices,
19 including North Dakota-specific practices.
- 20 • A comparison of the circumstances in these cases against those criteria.
- 21 • While non-authoritative to North Dakota, I discuss the proposed accounting
22 treatment in Minnesota including the use of the fuel clause adjustment (FCA)
23 as options for consideration by the Commission.
- 24 • Recommendation regarding the use of deferred accounting for the Pine Bend
25 and Laurentian Energy projects. My recommendation will discuss costs
26 authorized for recovery, implications related to excess earnings, amortization
27 periods, and a return on unamortized deferral balances.

28
29 **Q. Are you sponsoring any exhibits to your testimony?**

30 **A.** Yes. I am sponsoring the following exhibits:

- 1 • Exhibit JFJ-1: CV of Joel F. Jeanson
2

3 **II. North Dakota Legislative Statutes and Administrative Code**

4 **Q. What guidance is provided by North Dakota legislative statutes and**
5 **administrative code related to deferred accounting?**

6 **A.** There appears to be limited guidance provided by North Dakota legislative statutes
7 and administrative code related to deferred accounting. Subsection 03 of Chapter 69-
8 09-05.1 Accounting Practices indicates that:

9 “The system of accounts used by all North Dakota electric
10 companies subject to rate regulation by the commission must
11 conform to the uniform system of accounts set forth in title
12 18, Code of Federal Regulations, part 101, prescribed by the
13 federal energy regulatory commission.”

14 The specific guidance provided by the FERC Uniform System of Accounts related to
15 deferred accounting is provided below.

16 N.D.C.C. Chapter 49-05 Procedure on Regulation of Public Utilities, Section 49-05-
17 16. Advance determination of prudence, provides authorization for “an advance
18 determination of prudence” regarding a resource addition. “Resource addition” is
19 defined as “construction, modification, purchase, or lease on an energy conversion
20 facility, renewable energy facility, demand response system, transmission facility, or a
21 contract to acquire energy, capacity, or demand response for the purpose of providing
22 electric service.” Item 6 further indicates:

23 “The public utility may recover in its rates, and in a timely
24 manner consistent with the public utility’s financial
25 obligations, the amounts the public utility reasonably incurred
26 or obligated on a prudent resource addition, including accrued
27 allowance for funds used during construction, even though the
28 resource may never be fully operational or used by the public
29 utility to serve its customers. The cost amortization period for

1 a discontinued resource addition may not exceed five years
2 from the date commencement of the recovery is approved by
3 the commission. No return on amounts incurred or obligated
4 by the public utility may be authorized for the period after the
5 resource addition is discontinued. The public utility may
6 request an order from the commission for deferred accounting
7 treatment for costs incurred for a discontinued resource
8 addition.”
9

10 III. Industry Standards and Practices

11 Q. What industry standards and practices exist related to deferred accounting
12 treatment?

13 A. The Federal Energy Regulatory Commission (FERC) Uniform System of Accounts
14 (USoA) as set forth in Title 18, Code of Federal Regulations, Part 101 defines the
15 accounting treat for regulatory assets (i.e., deferred accounting) in account **182.3**
16 **Other regulatory assets** of the USoA.

17 A. This account shall include the amounts of regulatory-
18 created assets, not includible in other accounts, resulting
19 from the ratemaking actions regulatory agencies.

20 B. The amounts included in this account are to be established
21 by those charges which would have been included in net
22 income....in the current period under the general
23 requirements of the USoA but for it being probable that
24 such items will be included in a different period(s) for
25 purposes of developing rates that the utility has been
26 authorized to charge for its utility services.

27 Similarly, USoA definitions state:

28 31. *Regulatory Assets and Liabilities* are assets and liabilities
29 that result from rate actions of regulatory agencies. Regulatory

1 assets and liabilities arise from specific revenues, expenses,
2 gains, or losses that would have been included in net income
3 determination in one period under the general requirements of
4 the Uniform System of Accounts but for it being probable:

5 A. that such items will be included in a different period(s) for
6 purposes of developing the rates the utility is authorized to
7 charge for its utility services; or

8 B. in the case of regulatory liabilities, that refunds to
9 customers, not provided for in other accounts, will be
10 required.

11 As shown above, the FERC USoA is not prescriptive; that is, it does not identify those
12 specific transactions which require or are eligible for deferred accounting treatment or
13 even those criteria a regulatory agency should use to determine whether the recovery
14 of costs otherwise accounted for as expenses should be allowed over more than one
15 accounting period. Rather, recording a transaction as a regulatory asset or liability is
16 completely dependent on the rate actions of regulatory agencies.

17
18 In The Process of Ratemaking, published by Public Utilities Reports, Inc., Leonard
19 Saul Goodman defines a deferred cost as "one that has been paid by the company but
20 is postponed for inclusion in rates until a future period." He indicates that "the use of
21 the deferred cost account in a ratemaking context is so common and so fundamental a
22 regulatory tool that no agency is likely to consider it necessary today to study whether
23 as a matter of 'policy' costs should be deferred; however, it will insist that a proper
24 record be made pointing to the need for a specific cost deferral" and that "permission
25 to defer a cost for accounting purposes does not carry with it any promise that the cost
26 will later be allowed in rates, nor if allowed in rates that the unamortized balance will
27 be included in rate base" (that is, eligible for a "return on"). "The deferral is merely a
28 stop-gap measure to preserve the status quo until the company proves that the cost
29 should be allowed," (that is, typically in the context of a rate case). "There is usually

1 a ratemaking implication whose resolution the agency finds it convenient to defer
2 along with the affected costs.”

3 Goodman further provides the following insights:

4 When the company with commission approval postpones the
5 collection of a cost from ratepayers. It may be allowed to
6 create a “deferred cost” or a “regulatory asset” on its books
7 for a stated period. It thereby “capitalizes” the cost, and will
8 thereafter amortize the cost through charges to ratepayers with
9 or without inclusion of the unamortized balance in rate base.
10Amortization imposes costs on ratepayers; rate base
11 exclusion imposes carrying costs on shareholders.

12
13 **Q. Does your experience support the industry practices described above?**

14 **A.** Yes. Based on my experience, the practices described above align with practices I
15 have observed.

16
17 **Q. Based on your experience, are there common criteria or attributes of costs used
18 by regulators when authorizing the deferral of costs as regulatory assets?**

19 **A.** Yes. Based on my experience, the following criteria are commonly and consistently
20 used by regulators in authorizing cost deferrals and establishing regulatory assets:

- 21 • The costs are significant and extraordinary; that is, they are material relative
22 to the ongoing level of operating expenses, and are not currently recoverable
23 through rates.
- 24 • The costs incurred provide value to ratepayers.
- 25 • The costs incurred are necessary and reasonable (or “prudent”).
- 26 • The recovery period over which the costs will be amortized reasonably
27 represents the period over which value is provided.
- 28 • The recovery will not result in over-earning.

1 **Q. Do the criteria described above align with criteria used by the ND PSC in similar**
2 **requests for deferred accounting?**

3 **A.** I believe so. For example, in its order allowing cost deferral in Case No. PU-10-589
4 dated July 27, 2011, in which Montana-Dakota Utilities (MDU) requested approval for
5 the deferral and subsequent recovery of manufactured gas plant (MGP) remediation
6 costs, the Commission describes the following criteria used in approving the proposed
7 regulatory asset:

8 "Any future request for cost deferral must be made immediately
9 after the costs have been incurred and then only when current
10 earnings levels are not sufficient to cover these kinds of
11 extraordinary and unusual costs."

12 The case summary section of the one-page order provides further insight into likely
13 criteria considered by the Commission as follows:

- 14 • The company proposed collecting the cost over a five-year period beginning
15 January 1, 2010 with no interest or rate base treatment.
- 16 • The MGP site was only used to serve Bismarck customers prior to the
17 availability of transmission pipelines used today.

18 19 **IV. Summary of NSP Request**

20 **Q. Please describe the request for deferred accounting made by NSP related to the**
21 **cancellation of the Biomass PPAs in Docket No. PU-17-271.**

22 **A.** In its Application for Authority for Deferred Accounting, Northern States Power
23 requests authority for deferred accounting that would allow the Company to defer
24 recognition for the transactional, plant closing, and other associated costs of the
25 Benson and Pine Bend transactions.

26 In making this request, the Company represents the following:

- 27 • The cost savings from the Proposed Transaction will benefit customers in all
28 cases.

- NSP will incur transactional, plant closing, PPA buyout, and other associated costs that are unusual and non-recurring and were not contemplated by the Commission when setting rates.
- These costs are reasonable and prudent for the achievement of the net cost savings contemplated by the Proposed Transaction.

Once the Commission authorizes the Company to treat these costs as a regulatory asset and defer accounting so that they can be recovered in the future, the Company will propose mechanisms to recover these costs sometime in the future.

The Company further represents that under the Uniform System of Accounts, including Definition No. 31, that the “Commission may authorize deferred accounting and amortization of unusual and non-recurring expenses that were not contemplated when setting the current rates.” And by doing so, “the Commission allows a utility to designate unusual and infrequent expenses as ‘regulatory assets’ that will be amortized over future accounting periods.”

Q. What costs is the Company seeking to recover for the Benson and Pine Bend transactions using a deferred accounting mechanism?

A. The Company provides the following underlying cost assumptions for the Benson plant purchase and closure.

	Description	Amount (\$M)
1	PPA termination and asset purchase price	\$95.0
2	Contract termination fees	\$1.5
3	Legal, miscellaneous fees and insurance	\$1.5
4	Demolition, remediation and other related costs	\$8.8
5	Replacement energy costs	\$128.0
6	Fuel	\$1.0
7	Transportation	\$5.0
8	Landfill expense	\$0.3
9	Operating contracts, materials and supplies	\$4.9
10	Property taxes	\$3.5

1 Of these costs, NSP is requesting deferred accounting treatment in North Dakota for
2 North Dakota's share of the \$106.8M in costs in the first four rows of the above table
3 as well as the remaining \$14.5M in expenses in rows 6-10.

4 The proposed termination agreement with Pine Bend provides that in exchange for
5 terminating the PPA, monthly payments will be made by NSP to Gas Recovery
6 Systems (GRS) in the amount of the difference between the current PPA price and the
7 average monthly locational marginal price at the NSP node plus \$10/MWh until GRS
8 has received a total of \$1,050,000 or until the end of three years after monthly
9 payments have begun, whichever is earlier. NSP is also requesting deferred
10 accounting treatment for North Dakota's share of the Pine Bend termination payment.
11 The Company also requests that it be allowed to include a cost of capital return on the
12 regulatory asset for both the Benson and Pine Bend transactions. The Company plans
13 to propose mechanisms to recover these costs sometime in the future.

14 Further, the Company represents that it does not have excess earnings to offset the
15 higher costs and that, if deferred accounting treatment is not authorized, that these
16 costs could potentially require the Company to immediately file a rate case.

17
18 **Q. Please describe the request for deferred accounting made by NSP related to the**
19 **termination of the Laurentian Energy Authority (Laurentian) PPA in Docket No.**
20 **PU-17-322.**

21 **A.** In its Application for Authority for Deferred Accounting, Northern States Power
22 requests authority for deferred accounting that would allow the Company to defer
23 recognition of the costs of terminating the Laurentian PPA.

24
25 **Q. What costs is the Company seeking to recover for the Laurentian transaction**
26 **using a deferred accounting mechanism?**

27 **A.** The costs to be deferred in the regulatory asset for the Laurentian plant relate on to
28 North Dakota's share of the PPA termination payments totaling \$108,500,000.

1 The Company also requests that it be allowed to include a cost of capital return on the
2 regulatory asset for the Laurentian transaction. The Company plans to propose
3 mechanisms to recover these costs sometime in the future.

4 Further, the Company represents that it does not have excess earnings to offset the
5 higher costs and that, if deferred accounting treatment is not authorized, that these
6 costs could potentially require the Company to file a rate case.

7
8
9 **V. Assessment of the NSP Requests for Deferred Accounting**
10 **Treatment**
11

12 **Q. Does NSP's request for deferral satisfy the criteria described above?**

13 **A.** Yes, based on the description of the proposed transaction contained in the application,
14 the five criteria are satisfied:

- 15 • The costs are significant and extraordinary; that is, they are material relative
16 to the ongoing level of operating expenses, and are not currently recoverable
17 through rates.
- 18 • The costs incurred provide value to ratepayers.
- 19 • The costs incurred are necessary and reasonable (or "prudent").
- 20 • The recovery period over which the costs will be amortized reasonably
21 represents the period over which value is provided.
- 22 • The recovery will not result in over-earning.

23 This assumes that the amortization period will not exceed either the remaining length
24 of the PPA contract being terminated or the five-year period discussed in Item 6 of
25 N.D.C.C. Chapter 49-05 Procedure on Regulation of Public Utilities, Section 49-05-
26 16 as discussed above.

27
28 **Q. Does approval of deferred accounting treatment for these transactions relieve**
29 **the Company of any further burden of proof associated with the establishment**
30 **of the regulatory asset?**

1 A. No. In my opinion, the Company remains obligated to demonstrate that the actual
2 costs incurred are reasonable and necessary, as well as significant and extraordinary.
3 This can be accomplished by ensuring the costs deferred as regulatory assets are of
4 similar amounts and of a similar nature as those determined to be prudent if the ADPs
5 are approved. In addition, the Company must continue to demonstrate that the
6 recovery of these costs could not otherwise be funded through over-earnings.
7

8 **Q. Do the recommendations of James Heidell impact your assessment of NSP's**
9 **request for deferred accounting treatment?**

10 A. Yes, but only for as related to the shutdown of the Benson Biomass facility.

- 11 • **Pine Bend PPA.** Mr. Heidell recommends that the Commission conditionally
12 approve the ADP to terminate the Pine Bend PPA that currently expires at the
13 end of 2025 and make the monthly payments that total \$1,050,000. Based
14 upon his independent analysis, the estimated cost of replacement energy and
15 payments to Pine Bend will be less than the payments to Pine Bend that would
16 otherwise be paid under the existing contract.
- 17 • **Laurentian PPA.** Mr. Heidell recommends that the Commission
18 conditionally approve the ADP to terminate the PPA with Laurentian Energy
19 Authority. The PPA currently expires at the end of 2026. NSP is proposing
20 to pay \$108,500,000 in return for terminating the PPA. Based upon his
21 independent analysis, the estimated cost of replacement energy and payments
22 to the Laurentian Energy Authority will be less than the payments that would
23 otherwise be paid under the existing contract.
- 24 • **Benson Biomass Facility.** Mr. Heidell recommends that the Commission
25 conditionally approve the ADP to purchase the Benson biomass facility,
26 subject to a recommended adjustment to the approved purchase cost, as well
27 as shut the facility down since the cost of owning and operating the facility
28 exceed the cost of otherwise purchasing replacement electricity. The current
29 PPA expires at the end of 2028. NSP is proposing to purchase and shut down
30 the facility for \$106,800,000; Mr. Heidell recommends that NSP be allowed to

1 recover \$106,200,000 of those costs. As discussed in his testimony, Mr.
2 Heidell recommends excluding \$606,823 of costs related to the City of
3 Benson stranded asset.

4 Consistent with Mr. Heidell's testimony, absent other considerations, I recommend
5 that all identified costs as proposed by NSP – with the exception of the \$606,823
6 related to the City of Benson stranded asset – be authorized for deferred accounting
7 treatment.

8
9 **Q. While not authoritative in North Dakota, in Minnesota, NSP is seeking a**
10 **variance to the fuel clause adjustment (FCA) to allow non-fuel costs associated**
11 **with the termination of the PPAs to be recovered in the FCA. Are you familiar**
12 **with the recovery mechanisms NSP is proposing in Minnesota?**

13 **A.** Yes. For Benson, NSP recommends that all on-going O&M costs be recovered
14 through the FCA as incurred. For Laurentian, all costs would be recovered through
15 the FCA. NSP recommends that the \$106.8 million in Benson transaction costs also
16 be allowed for recovery through the FCA, but not on an as-incurred basis. Instead,
17 these costs would be deferred as a regulatory asset, earn a return based on NSP's cost
18 of capital, and amortized over the remaining eleven years of the PPA. In this case, the
19 amortization would flow through the FCA as expensed.

20
21 **Q. If the Commission were to consider the use of similar recovery mechanisms for**
22 **the recovery of these same non-fuel costs, how would that impact the need for**
23 **deferred accounting?**

24 **A.** In that case, the only costs to be deferred as a regulatory asset are the transaction
25 costs associated with the Benson facility buy-out and closure. For all other costs, it is
26 my expectation that accounting practices currently exist to match revenues and
27 expenses on NSP's books for timing issues related to fuel-related transactions.
28 The \$106.8 million in Benson transaction costs (less the City of Benson stranded
29 costs) should be allowed for recovery through the FCA in North Dakota, but not on
30 an as-incurred basis. Instead, these costs should be deferred as a regulatory asset and

1 amortized over an appropriate period – either the remaining eleven years of the PPA
 2 or the five-year period mentioned in Item 6 of N.D.C.C. Chapter 49-05 Procedure on
 3 Regulation of Public Utilities, Section 49-05-16 as discussed above. In either case,
 4 the amortization would flow through the FCA as expensed.

5
 6 **Q. How significant are these costs compared to costs currently recovered through
 7 the FCA?**

8 A. In 2017, the average monthly fuel cost adjustment was \$17,372,521. If we assume
 9 that North Dakota’s share of the Benson-related on-going costs and all Laurentian
 10 costs flow through the FCA as incurred, and North Dakota’s share of the \$106.2
 11 million in allowed Benson transaction costs are recovered through the FCA based on
 12 an 11-year amortization schedule, the impact to the monthly FCA is as follows:
 13

Monthly Costs	Years 1–2	Years 3-6	Years 7-11
Benson on-going costs	\$57,645		
Laurentian on-going costs	\$82,731	\$82,731	
Benson transaction costs	\$50,545	\$50,545	\$50,545
	Years 1–2	Years 3-6	Years 7-11
Total Amount Recovered (per Month)	\$190,922	\$133,276	\$50,545
Percent of Avg Monthly FCA (2017)	1.09%	0.76%	0.29%
<i>Total Costs Recovered</i>	\$4,582,128	\$6,397,248	\$3,032,700

14
 15 **Q. Would the recovery of these costs in this Docket be precedent-setting for future
 16 transactions?**

17 A. No. Based on our experience, utility regulatory commissions have substantial leeway
 18 regarding the use of deferred accounting mechanisms, including whether they view
 19 the circumstances in specific instances to be sufficiently unique to consider them to
 20 be non-precedent setting. In these cases, the Commission Order typically includes a
 21 statement to that affect.

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
26
27
28
29
30

VI. Recommendations

Q. Do you recommend that the Commission authorize deferred accounting for the Benson, Pine Bend and Laurentian transactions?

A. No. I recommend authorizing deferred accounting treatment for the transaction costs associated with the Benson facility buyout other than the City of Benson stranded investment costs. All other costs can be recovered through the FCA without establish a new and separate regulatory asset.

This recommendation does not preclude the commission from subsequent analysis of the reasonableness of the costs incurred.

Q. Do you recommend the use of the Fuel Clause Adjustment as the recovery mechanism for the Biomass PPAs?

A. Yes. By using the FCA as the recovery mechanism, all of the on-going costs and many of the transaction costs are recovered by NSP on a timely basis. Approximately 78% of all costs are recovered in the first six years, of which two-thirds are recovered as incurred. In my opinion, this represents a fair solution for both NSP's North Dakota's customers and NSP. As shown above, the recovery of these costs through the FCA does not have a significant impact on the amount of costs recovered through the FCA and should not unduly burden NSP's North Dakota customers.

Q. For the Benson transaction cost-related regulatory asset, do you recommend the inclusion of the regulatory asset in rate base and earn a return?

A. No. I recommend the amortization of the Benson transaction cost-related regulatory asset be recovered through the FCA, and not through base rates, and not earn a return on investment.

This recommendation could be revisited in the context of a general rate case. In the context of a general rate case, the Commission has a greater opportunity to weigh all

1 of the costs and benefits associated with including the regulatory asset in rate base
2 relative to other regulatory issues being considered.

3

4 **Q. Does this conclude your pre-filed testimony?**

5 **A. Yes.**



Curriculum vitae

Joel Jeanson

Principal Consultant



Joel has extensive experience in utility finance and accounting, utility ratemaking, financial and operational auditing, performance improvement, budgeting and management reporting. During his business career, he directed the accounting, budgeting, corporate performance and auditing departments at a major investor-owned utility. He began his career with a Big Eight public accounting firm. While in consulting, Joel has performed numerous independent assessments of utility performance on behalf of both utility management and regulators, and has completed a number of technical accounting studies. He has testified before several utility regulatory commissions.

Primary expertise	Related experience	Qualifications	Client list
<ul style="list-style-type: none"> Regulatory accounting Utility ratemaking Corporate performance management Performance improvement Management audits Cost allocations 	<ul style="list-style-type: none"> Utility management Independent audit 	<ul style="list-style-type: none"> CPA (inactive) Bachelor of Science in Business (Accounting Major) 	<ul style="list-style-type: none"> Vermont Department of Public Service LADWP Consolidated Edison National Grid HECO Public Service New Mexico

Primary expertise

Regulatory accounting – helping clients improve cost allocation practices to mitigate regulatory risks; completing specialized cost studies to support regulatory accounting and compliance activities

Utility ratemaking – helping clients develop and support revenue requirements; performing special studies of technical accounting issues

Corporate performance management – assisting clients improve performance by improving processes whereby strategic plans are aligned with business unit, functional and individual performance including performance measurement and management reporting processes

Performance Improvement – helping clients improve business processes through benchmarking and focus on value-adding activities

Management Audits – performing compliance, efficiency, and effectiveness audits of utilities on behalf of utility regulatory agencies and management, and assisting utility clients prepare for upcoming management audits

Key client achievements

Hawaii Gas - Lead consultant responsible for assessing technical accounting issues including cost allocations and clearing account processes in connection with the Company's upcoming rate case.

Vermont DPS – Lead consultant responsible providing an assessment of the financial capabilities of the combined entity in connection with a telecommunications industry merger and acquisition. Provided expert testimony.

LIPA – Project manager / lead consultant on two independent assessments of PSEG-LI's performance related to the Operating Service Agreement.

Consolidated Edison – Led the development of a comprehensive cost allocation manual in response to New York PSC management audit finding.

National Grid USA - Project manager on an engagement in which PA developed new accounting and cost allocation practices for the Service Company in connection with the client's implementation of SAP. Provided regulatory support associated with new practices.

SUEZ Water – Project manager for the independent assessment of the Company's cost allocation practices. This review was requested by the New York Public Service Commission. The PA Report was provided to the NY PSC.



Curriculum vitae

PNM Resources - Project manager responsible for completing a series of A&G capitalization studies as well as A&G studies required by the operating agreement for a large, jointly-owned power plant. Required developing an understanding of the Company's accounting system code block and cost charging / allocation practices.

FairPoint Communications - Provided audit preparation services in connection with a service quality audit required by the New Hampshire PUC.

Confidential Client - Lead consultant assessing the regulatory environment and potential regulatory risks in connection with the review of the Company's long-term financial forecast. This work was performed in connection with the potential sale of the Company as part of a bankruptcy proceeding.

Frontier Corporation - Lead consultant responsible for assessing the robustness of the financial forecast and reasonableness of assumptions used to project financial results in connection with a telecommunication industry acquisition valued at \$8 billion

Hawaiian Electric - Directed the development of a long-term financial forecast model. This model was initially used to identify rate impacts by customer class associated with the proposed long-term power supply implementation plan.

PSE&G - Provided support to the Company in preparing for an upcoming management audit. This included performing a diagnostic assessment of potential audit risks and employee training. Lead consultant for the review of cost allocations and related controls to ensure the utility was not subsidizing non-regulated operations for a large, east coast gas & electric utility in advance of a state regulatory commission-mandated management audit.

HECO - Corporate accounting performance improvement initiative and benchmarking; completed specialized regulatory accounting studies; performed financial modeling to support business design changes.

Washington Gas - Provided assistance in identifying potential merger synergies for support services functions.

EPCOR - Completed special study filed with the Alberta regulatory commission related to cost allocation practices and shared services.

LADWP - Developed cost management processes designed to support the Department's new tariff and regulatory framework. Directed the completion of water system revenue requirements, cost of service and rate design studies.

FirstEnergy-Pennsylvania - Assessed the effectiveness of the corporate management process and suggested changes to the process to better ensure the transparency of the process and linkages to operational plans and budgets.

NiSource - Provided a framework for assessing the value of corporate and shared services to the operating companies in connection with a NIPSCO rate case. Included a review and assessment of the Company's cost allocation practices.

Vectren - Performed a detailed assessment of cost charging and allocation practices to the individual affiliate operating companies post-merger and acquisition of the DPL gas properties. Assessed the effectiveness of the corporate management process and suggested changes to the process to better ensure the transparency of the process and linkages to operational plans and budgets.

New Jersey American Water - Provided assistance by performing a diagnostic assessment of utility performance in connection with an upcoming management audit and rate case.

City of Baltimore DPW - Lead consultant responsible for benchmarking water and wastewater treatment plant performance. Also lead development of performance / financial management-related recommendation.

Anaheim Public Utilities PUC - Project manager responsible for completing a comprehensive review of water and power meter reading and billing operations and controls.

City of Kansas City Water Department - Lead consultant on a comprehensive review of the water utility's finance and accounting function.

Arizona Corporation Commission - Project manager and lead consultant for the review of the meter reading, billing and usage estimation practices of Arizona American Water Company. Testified before the ACC related to the work performed.

The Metropolitan District (MDC) - Lead consultant for the restructuring of the financial organization of the MDC, a municipal water and sewer utility headquartered in Hartford, CT. Also, lead consultant for the review of financial, human resources, information technology and customer service in connection with a comprehensive management review of the District.



Curriculum vitae

Washington State Auditor's Office – Project manager for the performance audit of the three mid-Columbia Public Utility Districts. This performance audit was performed under Washing Legislative Initiative 900. The project team identified numerous opportunities for cost savings including the increased use of shared support services

Unitil Corporation – Reviewed cost allocation, management and control, and customer service processes for an east coast gas and electric utility in advance of a state regulatory commission-mandated management audit

Anaheim Public Utilities – Project manager for a meter reading and billing process improvement initiative, controls assessment, and billing integrity audit for a large, west coast municipal electric and water utility

City of LA – Water System project manager for two revenue requirements studies of the Los Angeles Department of Water and Power

CA PUC – Lead Consultant for the program evaluation of SBX1 5 energy efficiency and low-income assistance funds performed for the CPUC. Audited SDG&E and Southern California Gas's program and administrative costs for compliance with CPUC and Legislative requirements.

South Jersey Industries – Lead consultant for the review of cost allocations in preparation for an upcoming management audit. Provided a comprehensive re-write of the Company's cost allocation manual.

Direct Utility Industry Experience

- Head of Internal Audit – responsible for developing the internal audit plan, directing the completion of the planned work, and reporting results to the Audit Committee and senior management. Activities included compliance, operational and financial audits.
- Financial lead in merger integration – responsible for developing an overall assessment of financial impact of the merger as well as the identification of staffing levels, structure, systems and processes, and cost savings opportunities for the company's financial organization.
- Member of the management team – responsible for the implementation of shared services including establishing a separate shared services organization. Developed cost assignment and allocation processes for shared services.
- Project director for activity-based management – initiative focused on internal products and services. ABM used to assess performance against other service providers, measure performance, and improve performance.
- Directed the corporate business planning and budgeting process – responsible for integrating the strategic and operational planning processes so that departmental plans, capital and O&M budgets and performance measures would be focused on both continuous improvement and the achievement of corporate financial and non-financial objectives.
- Led customer service business process – improvement initiative that assessed performance and made recommendations for improvement of all customer service processes, leading to improved customer service and reduced costs. Facilitated the development of customer service standards and measurement processes.
- Key member of project team – that completed a study to identify the services, and levels of service, that customers are willing to pay for. This study resulted in significant changes in how the company delivered services to its customers.

Testimony Experience

SUEZ Water NA – Prepared expert report related to the cost allocation practices and cost of corporate and shared services of SUEZ Water NA. This report was filed by the Company with the New York PSC in connection with New York operating company's general rate case.

National Grid US – Worked with the Company to develop a new cost allocation manual (and associated cost allocation practices). Expert report prepared related to the work performed was filed by the Company in its Niagara-Mohawk general rate case.

Vermont DPS – Testified in connection with the proposed purchase of Verizon's northern New England properties by FairPoint Communications. Subsequently testified in connection with the proposed purchase of the assets of FairPoint Communications by Consolidated Communications.



Curriculum vitae

Arizona Corporation Commission – Prepared expert report and testified on behalf of the Arizona Corporation Commission's Utilities Division in connection with the meter reading and billing practices of Arizona Public Service

Arizona Corporation Commission – Prepared expert report and testified on behalf of the Arizona Corporation Commission's Utilities Division in connection with the meter reading and billing practices of Arizona American Water Company



Denver Office

PA Consulting Group Inc.
Suite 3550
1700 Lincoln Street
Denver
CO 80203
USA
+1 720 566 9920

paconsulting.com

This proposal has been prepared by PA Consulting Group on the basis of information supplied by the client, third parties (if appropriate) and that which is available in the public domain. No representation or warranty is given as to the achievability or reasonableness of future projections or the assumptions underlying them, targets, valuations, opinions, prospects or returns, if any, which have not been independently verified. Except where otherwise indicated, the proposal speaks as at the date indicated within the proposal.

All rights reserved

© PA Knowledge Limited 2019

This proposal is confidential to the organisation named herein and may not be reproduced, stored in a retrieval system, or transmitted in any form or by any means, electronic, mechanical or otherwise, without the prior written permission of PA Consulting Group. In the event that you receive this document in error, you should return it to PA Consulting Group, PA Consulting Group Inc., Suite 3550, 1700 Lincoln Street, Denver, CO 80203, USA. PA Consulting Group accepts no liability whatsoever should an unauthorised recipient of this proposal act on its contents.