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July 21, 2025

VIA EMAIL AND HAND-DELIVERY

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

In re: Montana-Dakota Utilities Co.
Advanced Prudence – Badger Wind
PU-25-75

Dear Mr. Kahl:

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

- Sheldon A. Smith*
- Scott K. Porsborg****
- Suzanne M. Schweigert*
- Mitchell D. Armstrong*
- Stacy M. Moldenhauer**
- David J. Smith*
- Brian D. Schmidt*
- Tyler J. Malm*
- Morgan E. Butland Wentz*

1. Testimony of James A. Heidell (w/ Exhibit JAH-1);
2. Declaration of James A. Heidell; and
3. Affidavit of Service.

We are also hand-delivering one copy of the following document in a sealed envelope labeled “**PROTECTED INFORMATION/TRADE SECRET – PRIVATE**”:

1. Testimony of James A. Heidell

36 PU-25-75 Filed 09/11/2025 Pages: 43
MDU Exhibit 8 - James A. Heidell Pre-Filed
Testimony, Attch. JAH-1 - PUBLIC
Montana-Dakota Utilities Co.

30 PU-25-76 Filed 09/11/2025 Pages: 43
MDU Exhibit 8 - James A. Heidell Pre-Filed
Testimony, Attch. JAH-1 - PUBLIC
Montana-Dakota Utilities Co.

19 PU-25-75 Filed 07/21/2025 Pages: 43
Pre-Filed Testimony of James A. Heidell with
Exhibit - Redacted

Montana-Dakota Utilities Co.
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Thank you for your attention to this matter.

Respectfully,

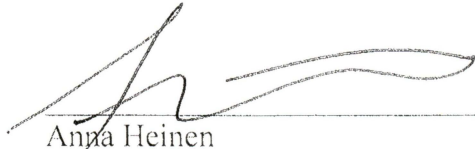


MITCHELL D. ARMSTRONG
Special Assistant Attorney General for PSC
Advocacy Staff

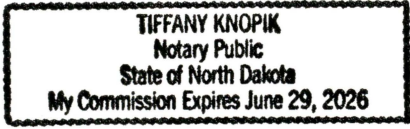
amh
enclosures

cc: Travis Jacobson (w/ Public enc.) (via email)
Zeviel Simpser (w/ Public enc.) (via email)

PSC.2


Anna Heinen

Subscribed and sworn before me this 21st day of July, 2025.




Notary Public
Burleigh County, North Dakota

Public Document

Trade Secret Data Redacted

TESTIMONY

JAMES A HEIDELL

STATE OF NORTH DAKOTA

BEFORE THE

NORTH DAKOTA PUBLIC SERVICE COMMISSION

MONTANA DAKOTA UTILITIES

CASE NO. PU-25-075

ADVANCE DETERMINATION OF PRUDENCE – BADGER WIND PROJECT

Public Document

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1 **I. Introduction**

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

3 **A.** My name is James A. Heidell, and I work as a Partner for PA Consulting Group, Inc.
4 (PA). My business address is 2420 17th Street, Suite 220, Denver, CO 80202.

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 42 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 CFA
17 charterholder. 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 have submitted testimony on behalf of Advocacy Staff in numerous dockets
21 including the following:

- 22 • Otter Tail Power Company's request for an ADP for the Astoria Station Onsite
23 Fuel Inventory System (Case Number PU-23-066);
- 24 • Northern States Power Company's request for an ADP for the Sherco Solar (Case
25 Number PU-21-152);
- 26 • Northern States Power Company's request for an ADP for the Heartland Divide II
27 Wind Project (Case Number PU-20-433);
- 28 • Montana-Dakota Utilities' 2020 Natural Gas Rate Increase Application (Case
29 Number PU-20-379);

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- 1 • Montana-Dakota Utilities’ request for an ADP and Certificate of Public
2 Convenience and Necessity for an 88 MW Simple Cycle Combustion Turbine
3 (CT) (Case Number PU-19-307);
- 4 • Northern States Power Company’s request for an ADP for the Dakota Range III
5 Wind Facility (Case Number PU-18-430);
- 6 • Northern States Power Company’s request for an ADP for the Dakota Range
7 Wind Project (Case Number PU-17-372);
- 8 • Northern States Power Company’s request for an ADP for 1,550 MW of Wind
9 (Case Number PU-17-120);
- 10 • Otter Tail Power Company’s Request for an ADP for the Astoria CT and
11 Merricourt Wind Project (Case Nos. PU-17-140, PU-17-141, and PU-17-143);
- 12 • Advance Prudence – Biomass Application for deferred accounting Northern
13 States Power Company (Case Nos. PU-17-270, PU-17-271, and PU-17-322); and
- 14 • Northern States Power Company Resource Treatment Framework (Case Nos. PU-
15 12-813 et al.).

16
17 **Q. What is the purpose of your testimony?**

18 A. The purpose of my testimony is to provide the Commission with my assessment of
19 Montana Dakota Utilities Company’s (Montana-Dakota or Company) Application for an
20 Advanced Determination of Prudence (the Application) for the Badger Wind Project, a
21 250 MW project near Wishek, North Dakota (Badger Wind, or the Project). Montana-
22 Dakota is seeking to purchase 122.5 MW of the Project, a 49% undivided ownership
23 interest. In addition, Montana Dakota will have a 27.5 MW Power Purchase Agreement
24 (PPA) with the Project, though the PPA is not part of the Application.

25
26 Montana-Dakota identified a need for the energy from this project in part due to the
27 expiration of the Minnkota PPA in May 2026. Montana-Dakota has stated that based
28 upon its analysis, the wind project is consistent with the findings in its 2024 Integrated
29 Resource Plan (IRP). Furthermore, the Company has stated that based upon its analysis,

1 ownership of the wind project provides a lower cost option for its customers compared to
2 either a twenty-year PPA (the current option), or the pricing offered for a 35-year PPA.
3

4 **II. Summary of Recommendations and Findings**

5 **Q. Do you recommend the Commission approve Montana-Dakota's ADP request for**
6 **the Project?**

7 A. Yes. Of the following three options that I evaluated, ownership of Badger Wind is a
8 reasonable choice:

- 9 1. Reliance on the Midcontinent Independent System Operator (MISO) market to
10 provide an equivalent amount of energy and capacity;
- 11 2. Acquiring a different type of generation resource to reduce dependence on the
12 MISO market; or
- 13 3. Acquiring the energy and capacity from a wind resource either through a PPA or
14 through ownership of the wind asset.

15
16 **Q. If the Commission approves Montana-Dakota's request, are you recommending**
17 **modifications?**

18 A. Yes, as conditions to any Commission approval of the ADP, I recommend that the
19 Commission limit the ADP to the forecast of the capital cost included in the Application.
20 In addition, the Commission should confirm that the Production Tax Credit (PTC) should
21 be levelized per Montana-Dakota's proposal to smooth out the rate impacts. Finally, I
22 recommend that Montana-Dakota bear the risk of a capacity factor significantly below
23 the Company's modelled assumption.
24

25 **Q. Would you please provide a summary of the findings you believe the Commission**
26 **should consider as it determines whether to approve Montana Dakota's Application**
27 **for an ADP?**

28 A. My key findings and observations include the following.

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- 1 • On a Net Present Value (NPV) basis, the cost of the electricity generated by the
2 project is expected to compare favorably to the MISO wholesale energy price forecast
3 with less volatility in the cost of the energy.
- 4 • Ownership is expected to create benefits for customers on a NPV basis. However,
5 customers will bear more risk over the first twenty years in the ownership scenario
6 versus the alternative PPA option.
- 7 • Acquiring a wind resource is the preferred option based upon the Company's analysis
8 in the 2024 IRP. However, it should be noted that Montana-Dakota did not conduct
9 price discovery through either a resource bidding process or soliciting a replacement
10 PPA for the Minnkota project.
- 11 • The benefits of ownership versus the PPA are dependent on the capacity factor of the
12 Project and operating costs. The Company did not assume any curtailment; however,
13 curtailment reduces the benefits of ownership.
- 14 • There is a risk under either the PPA or ownership scenario that congestion cost on the
15 MISO system may reduce the benefits of the wind Project.

16
17 **Q. Do you have additional specific findings?**

18 A. Based upon my review and analysis of the testimony filed in the Application, the exhibits
19 contained within the Application, and the information produced in discovery, I find the
20 following relevant in determining whether to approve the ADP for the Project:

- 21 • If the Commission determines that it will not grant an ADP, then it will at some point
22 need to address the prudence of the PPA for 150 MW that the Company has signed.
- 23 • The Project is currently under construction and presumably will go in service
24 regardless of the outcome of this proceeding. The output of the Project is not likely to
25 be altered as a result of the Commission's decision; as such, the impact on the MISO
26 market prices is unlikely to be impacted by the Commission's decision.
- 27 • Ultimately there is significant uncertainty as to whether the Project will result in lower
28 costs for customers compared to the alternative of MISO market purchases, but there

1 is an unquantified value associated with more certainty in future energy costs for the
2 Company's North Dakota customers.

- 3 • The benefits of ownership versus a PPA are not guaranteed due to uncertainty
4 regarding operating costs. However, uncertainty is inherent to any decision regarding
5 purchase of a long-life generation asset.
6

7 **III. Scope of Testimony**

8 **Q. Would you please summarize the scope of your testimony?**

9 A. Yes. I present a detailed discussion of my analysis and additional factors considered.
10 Finally, I propose conditions for the Commission to impose if it approves Montana-
11 Dakota's request for an ADP of the Company's proposed purchase of a portion of the
12 Badger Wind Project. My testimony is separated into the following sections:

- 13 • An overview of the Project (Section IV);
14 • An evaluation of the need for energy and capacity (Section V);
15 • A review and assessment of the generation options considered (Section VI);
16 • A review of the resource procurement process (Section VII)
17 • An assessment of the benefits of ownership versus a PPA (Section VIII);
18 • A summary of findings (IX); and
19 • My conclusions and recommendations (Section X)
20

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

22 A. Yes, I am sponsoring one exhibit: *Exhibit JAH-1: James Heidell CV*.
23

24 **IV. Overview of the Project**

25
26 **Q. Please provide an overview of Montana-Dakota's proposal to acquire 122.5 MW of
27 the Badger Wind Project?**

28 A. The 250 MW Project is being developed by Orsted Onshore North America and received
29 siting approval from the Commission in Case No PU-22-86 and -24-87. The project is

1 located in Logan and McIntosh Counties and is currently under construction.¹ Montana-
2 Dakota signed a twenty-year PPA in November 2024 for 150 MW of the project with the
3 option to purchase a 122.5 MW - a 49% share - and execute a PPA for 27.5 MW. The
4 total purchase cost is \$294M plus additional Montana-Dakota costs of \$1.5M. The North
5 Dakota jurisdictional share is approximately \$212M. The expected commercial operation
6 date is December 1, 2025. The project is under construction and has the necessary
7 construction permits including an interconnection agreement to the Montana-Dakota
8 Wishek Junction substation.

9
10 **Q. What happens if the Commission does not approve the ADP?**

11 A. My understanding is that Montana-Dakota remains committed to a twenty-year PPA for
12 150 MW.

13
14 **Q. Did Montana-Dakota include this project in their 2024 IRP?**

15 A. Yes, but not by name. The IRP includes a 150 MW wind resource referred to as “New
16 Wind Opportunity.”

17
18 **Q. What benefits of the Project does Montana-Dakota identify?**

19 A. Montana-Dakota identifies this project as fulfilling a need for an additional resource to
20 replace the expiring contract with Minnkota that provides approximately 659 GWH of
21 energy and 30 MW of capacity on an annual basis.² The Company also asserts that a
22 wind resource is the preferred new resource based upon analysis conducted for the 2024
23 IRP as well as supplemental analysis completed in conjunction with the ADP application.
24 Furthermore, the Company has indicated that ownership is preferred to the PPA. The
25 Company’s NPV analysis forecasts an ownership leveled cost of [TRADE SECRET
26 DATA BEGINS] [REDACTED]

27 [REDACTED] [TRADE SECRET DATA]

¹ As of May 2025, the Monthly Construction Report indicates civil work is ongoing. (PU-24-087.103)

² Montana-Dakota Utilities, 2024 FERC Form 1, p. 326-327.

1 ENDS] However, over a 35-year asset life, the levelized cost of ownership is [TRADE
2 SECRET DATA BEGINS] [REDACTED] [TRADE SECRET DATA ENDS] per MWh which
3 is favorable to the [TRADE SECRET DATA BEGINS] [REDACTED] [TRADE SECRET
4 DATA ENDS] fixed price of a 35-year PPA.³

5
6 **Q. What assumption is Montana-Dakota making regarding Badger Wind's electricity
7 production?**

8 A. The Company is assuming a 52% capacity factor each year over the 35-year life based
9 upon a P50 wind study.⁴ This equates to 558,012 MWh of energy generated on an annual
10 basis.

11
12 **V. Demonstration of Need**

13
14 **Q. Please summarize your findings related to the need for a new resource?**

15 A. My key findings include the following:

- 16
- 17 • Based upon the 2024 IRP sales forecast, the utility is not forecasting significant load
18 growth excluding data centers;
 - 19 • The need for the Project is not associated with data center demand;
 - 20 • The Company has a relatively high reliance on MISO market energy purchases; and
 - 21 • The expiration of the Minnkota contract in 2026 represents approximately 20% of the
22 Company's sales and absent replacing that energy with a new resource it will increase
23 the Company's reliance on MISO market purchases.

24 **Q. Is the utility expecting significant load growth absent data center load?**

25 A. No, the Company forecast a nineteen-year Combined Annual Growth Rate (CAGR) of
26 0.6% for its North Dakota service territory.⁵ The relatively low growth is driven in part

³ Montan-Dakota indicated it was offered a 35-year PPA, see Application 4.

⁴ Montana-Dakota referenced study by Badger Wind, LLC. Direct Testimony of Darcy Neigum, p 5. l 5.

⁵ Integrated Resource Plan 2024, Volume II, July 12, 2024, p C-6.

1 by macroeconomic factors including low growth in non-farm and mining employment
2 and a nineteen-year household CAGR of 0.8%.

3
4 **Q. Why is data center load excluded from the needs analysis?**

5 A. My understanding is that data center loads are treated as a different class of service under
6 the High Density Contracted Demand Response Rate 45 under which customers pay the
7 incremental cost of their service. The IRP notes that the load is not included in the
8 forecast because these customers are served either by MISO purchases, or alternative
9 supply arrangements.⁶

10
11 **Q. Is the Company's sales forecast reasonable?**

12 A. Yes, I reviewed the forecast methodology and the load growth forecast developed for
13 Montana-Dakota's 2024 IRP, and the forecast appears reasonable.⁷

14
15 **Q. Is the need for the Project driven by load growth?**

16 A. While even the relatively modest load growth will drive the need for new supply side
17 resources, the need is primarily being driven by the expiration of the Minnkota supply
18 contract and to avoid increased reliance on MISO market purchases.

19
20 **Q. What is the current supply mix for Montana-Dakota?**

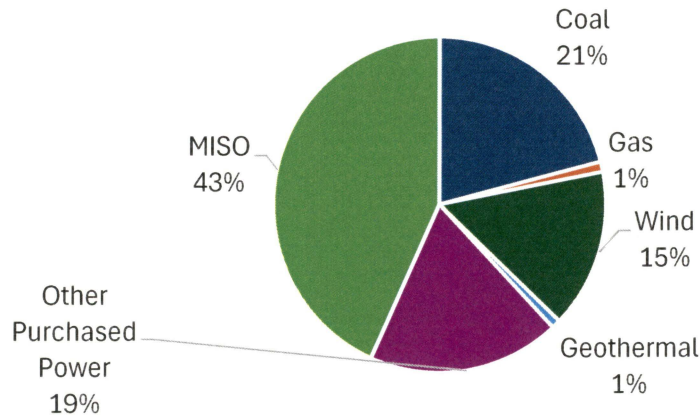
21 A. The supply mix for 2024 is shown in the following chart. PPAs supplied 19% of the
22 energy and market purchases supplied 43%.⁸

⁶ Integrated Resource Plan 2024, Volume I: Main Report, p. 19.

⁷ Integrated Resource Plan 2024, Volume II, July 12, 2024.

⁸ 2024 FERC Form 1

MDU 2024 Sources of Electricity



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8

Q. What is the Company’s historical reliance on MISO market purchases?

A. I have calculated the following reliance on MISO sales as a percentage of total MWh of all electricity sources based upon data in FERC Form 1. The Company’s reliance on the MISO market has increased over the past five years.

Year	MISO Market Purchases %
2024	42%
2023	40%
2022	27%
2021	26%
2020	22%

9
10
11
12
13
14
15
16
17

Q. What is the impact of the expiration of the Minnkota contract?

A. The Minnkota contract expires in May 2026 and provides approximately 659 GWh, or 15% of the Company’s energy requirements in 2024. If the Minnkota contract is replaced with MISO market purchases, market purchases will provide approximately 58% of the annual energy requirements. Increased reliance on market purchases is likely to add more volatility to energy costs and rates.

1 **Q. What are the disadvantages of reliance on MISO market purchases?**

2 A. First, it should be noted that relying on the MISO market for energy is not necessarily a
3 long-term decision. The utility could enter into a PPA or acquire another generation
4 resource in the future. However, it also takes time to develop generation resources and
5 obtain firm transmission interconnection capacity so there is a window of opportunity
6 associated with Badger Wind. A disadvantage of relying on market purchases is that it
7 creates volatility in energy costs and increased exposure to high-cost energy hours.

8
9 **Q. Is there a standard for what is a reasonable percentage of total sales that should be
10 fulfilled from utility-controlled generation assets?**

11 A. I am not aware of any standard; however, I note that if the utility increases its purchases,
12 it will have a high reliance on the market compared to its peers as shown in the following
13 table.
14

Utility	% of Energy from MISO Market Purchases ¹
Otter Tail Power	42%
Northern State Power	9%
Montana-Dakota	43%
1. Percentages based upon each company's 2024 FERC Form 1	

15
16 **Q. Does the Project provide an equivalent amount of capacity as the Minnkota
17 contract?**

18 A. No. While it is not the same amount, neither provide a significant amount of accredited
19 capacity, or zonal resource credits (ZRCs). The Minnkota PPA provides, on average, 30
20 MW of capacity in all seasons. Under a conservative summer wind ELCC⁹ view, the
21 combination of the owned and PPA components of Badger Wind (150 MW nameplate)
22 would provide 16.5 MW of potential ZRCs. In the winter, Badger Wind would provide
23 24 MW of ZRCs (based on a 16% DLOL ELCC).

⁹ Assuming the MISO Direct Loss of Load (DLOL) determination of accredited capacity

1
2 **Q. Based upon your assessment, is there a need for a new resource?**

3 A. Yes. Montana-Dakota currently has a relatively high reliance on MISO purchases and the
4 expiration of the Minnkota contract would significantly increase that reliance unless the
5 Company replaces the Minnkota contract with a different resource. It would also likely
6 lead to more volatility in North Dakota customers' energy costs.
7

8 **VI. Selection of Preferred Resource**
9

10 **Q. What is the current generation capacity mix for Montana-Dakota?**

11 A. The capacity mix is shown in the following table.¹⁰ The utility relies on a mix of coal,
12 natural gas, wind, and other resources to a lesser extent. The Minnkota contract accounts
13 for 30 MW during the mid-2023 – 2026 period.
14

Energy Source	Summer Nameplate (MW)	Summer ZRCs
Coal	214.9	208.4
Natural Gas	278.5	350.3
Wind	205	50.8
DSM		25.7
Contracts		12%
Other	4.1	3.5

15
16 **Q. Did Montana-Dakota develop an analysis to specifically replace the Minnkota
17 contract?**

18 A. No, Montana-Dakota relied upon its 2024 IRP. The IRP did not focus solely on replacing
19 the Minnkota contract. The Company evaluated resources to meet its energy capacity
20 needs based upon the forecast of loads, existing units, retiring generation units and
21 terminating contracts, and a range on new supply and demand side resources.
22

¹⁰ 2024 Integrated Resource Plan, pp. 7 - 9, Tables 2-1, 2-2, and 2-3.

1 **Q. What supply side resources were evaluated in the IRP?**

2 A. The IRP evaluated a range of resources, but the more viable near-term options were gas
3 turbines, combined cycle units, wind turbines, and solar paired with storage, storage, and
4 purchased capacity contracts. The wind projects included three alternatives: self-build 50
5 MW, self-build 100 MW, and the New Wind 150 (the Badger Wind opportunity).
6

7 **Q. Did the three wind options have different cost attributes?**

8 A. Yes, the cost of the self-build 100 MW and 50 MW options included the same type of
9 turbine and were developed by 1898 & Co., a qualified independent engineering firm.
10 The 50 MW option assumed a total cost (2024\$) of \$2,723/kW while the 100 MW option
11 was \$2,205/kW. The New Wind 150 option used a PPA cost supplied by Badger Wind.¹¹
12

13 **Q. Did you review the modeling?**

14 A. Yes, I reviewed the key inputs for reasonableness and reviewed the study results. I did
15 not review the accuracy of how the inputs were entered into the EGEAS model¹² or the
16 specific parameters used in conjunction with running EGEAS.
17

18 **Q. What key inputs did you review?**

19 A. I reviewed the natural gas forecast, the MISO energy forecast, parameters for new
20 generation units, and the load forecast.
21

22 **Q. What conclusions did you reach associated with your review of the key inputs?**

23 A. I reached the following conclusions:

- 24
- The load forecast methodology is reasonable (noting that I did not focus on the data
25 center loads);
 - The MISO forecast was in the range of reasonableness;
26

¹¹ Montana-Dakota response to Advocacy Staff Data Request 4-6.

¹² Montana-Dakota uses the commercially available EGEAS production cost model to aid in its resource acquisition planning decisions.

- 1 • The natural gas price forecast was in the range of reasonableness; and
2 • The range of generation options were reasonable, and I accepted the assumed costs on
3 the basis that they were developed by a qualified independent engineering firm.¹³
4

5 **Q. Did you review the 2024 IRP model results?**

6 A. Yes, Montana Dakota ran several scenarios and cases in EGEAS. I focused on the winter
7 and summer scenarios that reflected least cost assuming the MISO DLOL determination
8 of accredited capacity. These scenarios included a range of gas price scenarios and
9 market price scenarios. I also looked at the one scenario that included the Badger Wind
10 proxy.
11

12 **Q. Was Badger Wind identified as a least cost resource addition in the 2024 IRP?**

13 A. Yes, the proxy for the Badger Wind PPA (New Wind 150) was slightly lower than the
14 base case in the scenario that incorporated the New Wind 150 option. On a forty-year
15 NPV basis, the cost was 0.76% lower than the base case in the Summer DLOL scenario
16 and 0.41% lower in cost in the Winter DLOL scenario.
17

18 **Q. Did Montana Dakota perform any supplemental modeling after issuing the IRP?**

19 A. Yes, to support the ADP filing the Company did an analysis assuming ownership of
20 122.5 MW of Badger Wind and a 27.5 MW PPA. In the Winter DLOL Base Case the
21 Company needs a 94.8 MW CT in 2027. In the Badger Wind case the Company
22 purchases 80 MW of purchased capacity over the 2027 – 2032 period and 50 MW of
23 storage in 2033. The Badger Wind case has a 7.94% lower forty-year NPV.
24

25 **Q. Was the cost for the Badger wind ownership and 27.5MW PPA different from the**
26 **New Wind 150 option modeled in the 2024 IRP?**

¹³ Resource options were developed by 1898 & Co. and presented in Appendix E of Volume 3 of the 2024 IRP. 1898 & Co. was established by Burns & McDonnell to focus on consulting and technology.

1 A. Yes, the Company used the costs included in the financial model as the basis for this
2 ADP.

3
4 **Q. Do you have any concerns regarding the conclusion that Badger Wind is the least**
5 **cost resource addition?**

6 A. Yes, I am concerned that the risk of curtailment was not fully explored. I am inferring
7 that one of the factors contributing to additional savings compared to the base case
8 demonstrated in the supplemental analysis versus the IRP is the higher capacity factor.
9 The IRP assumed a 47.5% capacity factor while the Company's financial model assumes
10 a 52% capacity factor. I acknowledge that the IRP assumes a generic site while the
11 Badger Wind project capacity factor is based upon a specific site and wind study.
12 However, Montana-Dakota does not assume any curtailment. I am also concerned that
13 the model results were not tested through a competitive procurement process.

14
15 **Q. Would you please elaborate on your concern related to the risk of curtailment?**

16 A. Yes, while Montana-Dakota evaluates curtailment impacts under increased load
17 scenarios, it does not address several other critical factors that could influence
18 curtailment risk for wind projects in the region.¹⁴

- 19 • First, the study assumes a static generation mix and does not consider the likely
20 addition of resource additions in the region. As resource penetration increases, and in
21 particular renewable resources, local transmission congestion may intensify,
22 especially during periods of high generation and low demand, leading to more
23 frequent and severe curtailment.
- 24 • Second, the analysis overlooks the extent to which certain market rules and
25 interconnection agreements influence dispatch priority. For instance, new wind
26 projects, particularly those without firm transmission rights, may be curtailed ahead
27 of existing resources, reducing their operational and financial viability.

¹⁴ Montana-Dakota response to Advocacy Staff 2-3.

- 1 • Additionally, the study does not model the role of operational flexibility, such as how
2 battery storage or hybrid wind-plus-storage systems could mitigate or contribute to
3 curtailment in the region.

4
5 **Q. Would you please elaborate on your concern related to not testing the results**
6 **through a competitive procurement process?**

7 **A.** Yes, while Montana-Dakota identified factors such as a transmission interconnection
8 agreement, near the start of construction, and availability of the PTC that together make
9 Badger Wind appear financially attractive, it is not a test of the market. A competitive
10 procurement could identify a lower cost option, potentially an alternative solution that is
11 more attractive or one that offers more flexibility.

12
13 **VII. Resource Procurement Process**

14
15 **Q. Is an IRP the typical process to identify a specific resource to procure and the cost**
16 **of that resource?**

17 **A.** No, the IRP identifies the types of resources that are targeted, but the costs are typically
18 based upon assumptions in the IRP. The procurement process identifies actual costs.

19
20 **Q. Did Montana-Dakota undertake a procurement process to identify competitive**
21 **market costs?**

22 **A.** No, the Company indicated that they did not conduct a competitive procurement process
23 for resources or look for a replacement PPA beyond reaching out to Minnkota to ask
24 about renewal of the contract.¹⁵

25
26 **Q. Do utilities always conduct a procurement process?**

27 **A.** No, there are instances where there are unique opportunities, a critical need, or a critical
28 timeline that creates a lost opportunity. However, that does not necessarily obviate a

¹⁵ Montana-Dakota response to Advocacy Staff 1-5.

1 need for an analysis and demonstration of why a competitive procurement process was
2 not used.

3
4 **Q. Did Montana-Dakota conduct any analysis beyond the IRP to determine that
5 Badger Wind is the least cost wind resource to acquire?**

6 A. No, not that I am aware of.

7
8 **VIII. Assessing the Benefits of Ownership vs. a PPA**
9

10 **Q. Please summarize the purpose of identifying the benefits of a PPA versus ownership
11 of Badger Wind?**

12 A. In November 2024, Montana-Dakota signed a twenty-year PPA with Orsted Onshore
13 North America for rights to 150 MW of the energy, capacity, and renewable credits
14 associated with the 250 MW project. Section 2.5 of the PPA gives Montana-Dakota the
15 option to purchase a 49% share of the 250 MW project along with converting the 150
16 MW PPA to a 27.5 MW PPA. Montana-Dakota has elected the purchase option
17 contingent on approval of an ADP along with other conditions. If the Commission does
18 not approve the purchase, the PPA for 150 MW would remain in effect.

19
20 It is important to determine whether Montana-Dakota's election of the purchase option is
21 in the best interest of customers in addition to evaluating the need for a generation
22 resource as well as the determination that a wind resource is an appropriate generation
23 resource. I also note that Montana-Dakota's 2024 IRP does not address the issue of
24 whether ownership is preferable to a PPA.

25
26 **Q. What is the basis for Montana-Dakota's determination that ownership is the
27 preferred option?**

28 A. Montana-Dakota developed an annual revenue requirement model and compared the
29 levelized cost of ownership versus the PPA. As noted in the ADP Application, the
30 twenty-year PPA and a twenty-year ownership option have the same NPV. However,

1 when analyzed on a 35-year term, ownership has a lower NPV. The ADP also notes that
2 the Project provides a hedge against market prices.
3

4 **Q. Do both the PPA and ownership options present a hedge against market prices?**

5 A. Yes, both options provide a hedge against market prices for twenty years. The PPA does
6 not provide a hedge beyond the PPA expiration date. Alternatively, the PPA provides the
7 opportunity to pursue a replacement generation resource after the PPA expiration.
8 Whether that opportunity is beneficial to customers is an unknown as it would be
9 speculating on market energy prices, available generation technologies, and costs twenty
10 years from now.
11

12 **Q. Did you review the Company's financial model and the PPA?**

13 A. Yes, I reviewed both confidential documents and I have both general and specific
14 comments related to the analysis.
15

16 **Q. What are your general comments?**

17 A. Like any model, the model contains several assumptions regarding the ongoing cost of
18 ownership as well as the level of generation. The analysis is based upon a single set of
19 assumptions despite inherent uncertainties over a twenty- or thirty-five-year analysis. For
20 example, even if the ownership costs were known with certainty, changes in generation
21 would result in a different calculated levelized cost of energy. The project is largely
22 composed of fixed costs, i.e. the cost of owning, operating, and generating electricity
23 does not change with the amount of electricity produced by the Project. The uncertain
24 levelized cost of ownership is compared with a defined contractual price that is almost
25 exclusively independent of the seller's actual cost of ownership. Under the PPA,
26 Montana-Dakota is only responsible for paying a fixed price per MWh delivered by the
27 Project.
28 Montana-Dakota also compares the 35-year levelized cost with the contract price as
29 defined in the 35-year PPA price referenced by Orsted. The PPA that I reviewed does
30 not include an option to select a 35-year PPA. However, the PPA has a twenty-year

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1 Delivery Period. While the 35-year PPA may have been an option at one time, at this
2 point my impression is that if the purchase option is not pursued, then the Company will
3 have a twenty-year PPA and in year 21 would need to acquire an additional resource or
4 PPA to replace the energy and capacity. The Company does not appear to have analyzed
5 that potential outcome.
6

7 **Q. Do you have specific comments about the results from the Company's levelized cost**
8 **model?**

9 A. Yes, the economics of ownership is sensitive to the assumed generation. The Company
10 uses a P50 model and while that is a reasonable starting point, and although production is
11 location specific, I note that the 52% capacity factor and associated generation
12 assumption is relatively high.
13

14 **Q. What is the basis for your comment that the assumed production is relatively high?**

15 A I reviewed historical performance data for wind projects located near the Badger Wind
16 site and found that while a 52% capacity factor is not unreasonable, it is on the higher end
17 of observed values. One project, located in the same county and electrical area as the
18 proposed facility in McIntosh County, North Dakota, reported capacity factors ranging
19 from 38% to 45% between 2021 and 2024. Another project in Emmons County, North
20 Dakota, (similar tower height to that of Badger Wind), approximately 20 to 30 miles
21 away, recorded capacity factors between 42% and 51% over the same period. In all cases
22 reviewed, the 52% assumption exceeds historically observed averages but remains within
23 a plausible range. However, it does introduce some risk. Any reduction in the assumed
24 capacity factor adversely impacts the calculated benefits of ownership versus the PPA.
25

26 **Q. Is the PTC a risk factor?**

27 A. Montana Dakota states that the Project's ability to capture the PTC should not be a risk
28 since the project is in construction.¹⁶ Based upon the One Big Beautiful Bill Act

¹⁶ See Company response to Advocacy Staff Request No. 1-3

Trade Secret Data Redacted

1 (OBBBA) passed on July 4, 2025, that appears to be a reasonable assumption. However,
2 I note that it could still be a risk due to future changes in law. Under the ownership
3 option, that risk is borne by the Company and / or customers. Under the PPA [TRADE
4 SECRET DATA BEGINS] [REDACTED]
5 [REDACTED]¹⁷ [TRADE SECRET DATA ENDS]. The model also includes a conservative
6 PTC inflation assumption.
7

8 **Q. What is the generation risk?**

9 A The PPA requires the Company to pay a set price per MWh. Regardless of the
10 generation, the price does not change. However, the Company is compensated if annual
11 production drops below a guaranteed level. Under Company ownership there is no
12 guaranteed production, and higher or lower production will result in either a lower or
13 higher realized levelized cost. The Company assumes a 52% capacity factor based upon
14 a P50 model of the wind resource. Furthermore, the Company does not assume any
15 curtailment over the 35-year project life. As a sensitivity, I have used the Company's
16 model to evaluate the change in levelized cost using different annual production
17 assumptions. Reduced generation (a lower capacity factor) results in customers paying a
18 higher price for each MWh of wind delivered from the Project.
19

20 **Q. What is the congestion risk?**

21 A. PA understands that the project faces congestion risk due to being located in a region
22 with limited transmission capacity. While congestion can sometimes result in higher
23 Locational Marginal Prices (LMP) at certain nodes, this does not automatically benefit
24 generator owners. The actual impact depends on the generator's position relative to the
25 constraint, whether it holds firm transmission rights, and whether the LMP at the
26 project's bus is lower than the system or hub price (creating a basis differential). Projects
27 impacted by historical or persistent transmission constraints may also face curtailment
28 during peak congestion periods, reducing delivered energy and affecting project

¹⁷ See Section 3-7 of the PPA.

Trade Secret Data Redacted

1 cost certainty declines to around [TRADE SECRET DATA BEGINS] [REDACTED]. [TRADE
2 SECRET DATA ENDS] While inflation, property tax, and insurance risks are estimated,
3 they are generally stable and predictable. The primary area of variability lies in the
4 forecast of turbine maintenance costs beyond the GE TSA term. The cost is both
5 significant and is likely the biggest unknown. After the service agreement ends the
6 turbine maintenance costs are forecast to account for [TRADE SECRET DATA
7 BEGINS] [REDACTED] [TRADE SECRET DATA ENDS] of the operating costs.

8
9 **Q. Is the NPV of the benefits calculated by Montana-Dakota sensitive to the ongoing
10 operating cost assumptions?**

11 A. Yes, the NPV of benefits of project ownership calculated by Montana-Dakota is sensitive
12 to assumptions regarding ongoing O&M costs, particularly beyond the initial GE TSA
13 period.

14
15 To assess this risk, I reviewed projections from the National Renewable Energy
16 Laboratory's Annual Technology Baseline (NREL ATB) for wind turbine O&M costs.
17 I modeled an O&M cost increase of 11% year over year following the expiration of the
18 GE turbine TSA. This resulted in a 4.4% increase in ownership costs on a \$/MWh basis,
19 highlighting a material sensitivity in the NPV to the O&M assumptions post the GE TSA.
20 This risk has not been explicitly addressed in the company's current analysis. While the
21 first decade benefits from cost stability, the long-term financial outlook is exposed to
22 escalating O&M costs, which diminishes the projected benefits of utility ownership.

23
24 **Q. Are there benefits associated with ownership versus a twenty-year PPA?**

25 A. Yes, there is more certainty regarding the cost of the energy in years 21 – 35 compared to
26 purchasing an equivalent resource or PPA for years 21 – 35. In addition, there may be
27 benefits of land control and brownfield development cost savings past year 35 depending
28 on the terms of the land leases.

29
30 **Q. Why do you think there is more certainty?**

Trade Secret Data Redacted

1 A. While the power production and operating costs for Badger Wind as well as a new wind
2 resource are not known with certainty, the cost of a replacement asset is also not known.
3 For example, my levelized cost estimate for a new wind resource in twenty years is
4 between approximately \$65–\$70/MWh. If a replacement PPA were signed at the end of
5 the twenty-year PPA, I expect it to cost more than the [TRADE SECRET DATA
6 BEGINS] [REDACTED] [TRADE SECRET DATA ENDS] assumed by the Company
7 for a 35-year PPA.

8
9 **Q. What does the range of costs represent?**

10 A. The range of levelized costs for a new wind resource over the next 20 years reflects
11 varying degrees of technological innovation and learning curves, as estimated by NREL.
12 These projections of levelized costs encompass both moderate and conservative
13 scenarios, based on assumptions about future cost reductions, economies of scale,
14 financing, and production of the project. The moderate scenario assumes a steeper cost
15 reduction curve, projecting a levelized cost of energy decline of approximately 16%,
16 while the conservative scenario estimates a more modest 9% reduction over the same
17 period. However, there are inherent uncertainties in these cost curves, and if
18 technological progress or market conditions do not evolve as anticipated, actual levelized
19 costs of energy may not decline as projected.

20
21 **Q. How did you develop that estimate?**

22 A. I leveraged projections from the NREL ATB for wind turbines, which include estimates
23 for Levelized Cost of Energy (LCOE). To align with the specific characteristics of the
24 Project, I modified the default NREL financing assumptions (debt to equity ratio) to
25 reflect those used in the Project's financial model (50/50 split of debt to equity), and
26 similarly updated estimated capital costs, O&M, and capacity factors to align with project
27 estimates. Capital costs are based on the company's 2025 estimates and are adjusted
28 according to learning curve projections provided by NREL, as discussed above.
29 According to NREL, capital costs are expected to decline by 13% and 24% under

1 conservative and moderate scenarios, respectively. My estimate of the levelized cost also
2 does not incorporate any savings from a PTC or ITC.

3
4 **Q. What are the value implications of ownership versus the PPA if the replacement**
5 **PPA cost \$69.70 / MWh under the conservative scenario?**

6 A. Using the Company's model, when the average estimated LCOE of \$69.70/MWh is
7 applied to the replacement PPA in years 21-35, project ownership remains a lower cost
8 option for customers, with a levelized cost of \$38.60/MWh compared with a 35-year PPA
9 at [TRADE SECRET DATA BEGINS] [REDACTED] [TRADE SECRET DATA
10 ENDS]. This highlights the significance of re-contracting risk the Company could face
11 over a 20-year horizon if Badger Wind reverts to a twenty-year PPA for 150 MW. Any
12 PPA price exceeding approximately \$44 /MWh at the time of renewal would be more
13 expensive for customers compared with estimates of ownership provided by the
14 company, posing a material risk.

15
16 However, when incorporating the O&M cost escalation discussed earlier, based on NREL
17 ATB projections post the GE FSA, ownership becomes less favorable, with costs rising
18 to [TRADE SECRET DATA BEGINS] [REDACTED]
19 [REDACTED] [TRADE SECRET DATA ENDS] This gap widens further if O&M is
20 further increased, or the Project's capacity factor is reduced from the assumed 52% due
21 to potential curtailment.

22
23 These findings highlight that the value of ownership is sensitive to three key
24 assumptions:

- 25
- 26 • The future PPA price used to extend energy procurement beyond year 20 assuming a
27 twenty-year PPA;
 - 28 • O&M cost escalation after the initial turbine service agreement; and
 - 29 • The long-term capacity factor of the facility and risk of curtailment.

1 operations as well as managing capital renewal, replacements, and improvements.²¹
2 However, the agreement also provides protections for Montana-Dakota and its customers
3 associated with certain terms:

- 4 • Montana-Dakota may comment of contracts exceeding \$2.5M in any twelve-month
5 period but does not have veto power (Section 4.6 of Co-Tenancy Agreement);
- 6 • Montana-Dakota is not obligated to agree to re-powering (Section 4.9 of Co-Tenancy
7 Agreement); and
- 8 • Montana-Dakota is required to provide approval for annual capital improvements
9 exceeding the annual budget by \$500,000 if those improvements are not associated
10 with repair, restoration, or reconstruction. (Section 4.10 of Co-Tenancy Agreement)

11
12
13 **Q. Based upon your analysis, have you concluded that ownership is the better option**
14 **for customers?**

15 **A.** Yes, if the ADP is approved with a protection for customers against significant amounts
16 of curtailment. Based upon Montana-Dakota's assumption regarding production and my
17 assumption regarding the cost of replacing the PPA in year 21, there are benefits to the
18 ownership model. I want to emphasize that the benefits are not certain since in the
19 ownership model Montana-Dakota bears the risk of operating costs increasing. However,
20 Montana-Dakota assumed no curtailment, and such practice is optimistic given the long-
21 time frame, uncertainties regarding what resources may come online to exacerbate the
22 problem, and the longevity of anticipated data center load.

23 Ownership, while carrying risks related to the uncertainty of the capacity factor and
24 O&M costs, must be weighed against the re-contracting risk of a PPA 20 years from now,
25 an inherently uncertain proposition. Although continued declines in capital costs may not
26 materialize, my analysis shows that a real capital cost would have to decline significantly
27 more than the NREL ATB forecast to improve the economics of the PPA option. While

²¹ Badger Wind Co-Tenancy Agreement 4.5 (d) p 12.

1 some forecasts anticipate cost reductions, they are not guaranteed, and in some cases,
2 other forecasts may very well indicate that project construction costs will increase due to
3 factors like supply chain constraints, labor shortages, or inflationary pressures. This adds
4 further uncertainty to the prediction that future projects will be significantly less costly.
5

6 **Q. How do you propose that the curtailment risk be shared between customers and**
7 **Montana-Dakota?**

8 **A.** My proposal is to share the risk based upon the following logic - if the operating costs are
9 in line with the forecast, customers are roughly better off with the PPA if the capacity
10 factor is between 47% and 52% (a five percent band). Applying this 5% band on the
11 downside, the customers are worse off if the capacity factor is between 42% and 47%.
12 Therefore, I propose the Company bear the cost difference if the annual capacity factor
13 drops below 42%. An adjustment would be based upon the MWh shortfall multiplied by
14 the twenty-year PPA price. I also note that the 42% threshold is [TRADE SECRET
15 DATA BEGINS] [REDACTED]
16 [REDACTED]
17 [REDACTED] [TRADE SECRET DATA ENDS]
18 based upon the Company assuming the Project will have a 52% capacity factor.
19

20 IX. Summary of Findings

21

22 **Q. Is it reasonable to replace the expiring Minnkota contract with a resource other**
23 **than MISO market energy purchases?**

24 **A.** Yes, while there is no standard for the appropriate amount of exposure to the MISO
25 market as the advantages and disadvantages of relying on the market shift over time, my
26 assessment is that not increasing reliance on the market is reasonable especially in
27 consideration of the existing transmission access and the ability of Badger Wind to
28 qualify for PTCs.
29

30 **Q. Is it reasonable to commit to a wind resource versus other resource options?**

Trade Secret Data Redacted

- 1 • Montana-Dakota has reasonably demonstrated a need for an additional resource;
- 2 • Based upon a choice of acquiring a wind or gas resource to meet the energy need, a
- 3 wind resource is a reasonable option;
- 4 • While there are risks that ownership is not a better option for customers, the Company
- 5 has demonstrated a reasonable case for ownership based upon my analysis and
- 6 adjustments and sensitivities performed on the Company's model; and
- 7 • Based on the same reasoning, the Commission should grant the Company's
- 8 application for a Certificate of Public Convenience and Necessity.
- 9

10 **Q. If the Commission approves the ADP should there be any conditions?**

11 **A.** Yes, I recommend that approval include the following conditions:

- 12 • The ADP should be limited to the capital cost estimate provided in Montana-Dakotas'
- 13 Application. Should the actual cost exceed the estimate, the additional costs should
- 14 be evaluated for prudence;
- 15 • There should be a sharing of the curtailment risk between the customers and the
- 16 Company. The customers bear curtailment risk down to a 42% capacity factor in any
- 17 year and the Company bears the risk below 42%; and
- 18 • The Commission should affirm the Company's proposal to normalize the PTC credits
- 19 per past precedent on existing wind projects Cedar Hills, Diamond Willow, and
- 20 Thunder Spirit.
- 21

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

23 **A.** Yes.

24

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 Public Utility Commission of Nevada, Direct Testimony & Exhibits of James A. Heidell, In the Nevada Power Company 2025 General Rate Case, Docket No. PU-25-02016.

Before the North Dakota Public Service Commission, Direct Testimony & Rebuttal Testimony and Schedules of James A. Heidell, In the Matter of Otter Tail Power Company Advance Determination of Prudence – Astoria Station Onsite Fuel Inventory System, Case No. PU-23-066.

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

Before the North Dakota Public Service Commission, Direct Testimony and Schedules of James A. Heidell, In the Matter of Northern States Power Company Advance Prudence – Heartland Divide II Wind Project, Case No. PU-20-433.

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

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

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

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

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

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

• PU-25-75
Exhibit JAH-1

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.

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.

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.

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

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

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

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

Directed the valuation of the entire NRG portfolio on behalf of the bank creditors in the NRG bankruptcy hearings. The valuation work included advising on a range of types of generation assets in the U.S. as well as in Europe, South America, and the Asia-Pacific region. Mr Advised on the fairness of offers for assets being disposed of by NRG. Assisted creditors in the valuation of assets in the NEG bankruptcy including the options for completing unfinished gas-fired generation assets. Served as the interim finance manager for the Lake Road Generation facility.

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

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

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

ASSET APPRAISALS

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

Prepared 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.

- **Evaluation of Distributed Energy and Behind the Meter Generation** – Forecast of margins of community solar projects, portfolios of customer sited PV projects, and analysis of regulatory policies and rules associated with community solar projects and behind the meter PV projects.
- **Renewable Energy Technologies** – Develop business plans, market positioning strategies, and financial analysis of renewable technologies including PV cell manufacturing, flywheels, and fuel cells along with renewable generation technologies including solar thermal, geothermal, wind, battery storage, and IGCC projects.
- **Asset Valuation / M&A Advisor** – Provide valuation advice for acquisition of electric generation portfolios, single power plants, transmission projects, electric utilities, and gas distribution companies. Work also included review of wholesale and retail regulatory pricing mechanisms and analysis of associated risk.
- **Damages Estimation for Civil Litigation Testimony** – Prepare expert witness testimony to support power contract litigation, property tax cases, power plant development agreements, and quantification of economic damages.

EXPERIENCE

CIVIL LITIGATION TESTIMONY & SUPPORT

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

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

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

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

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

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

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

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

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

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

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

ANALYSIS OF RENEWABLE ENERGY INVESTMENTS

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

JIM HEIDELL

PARTNER



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

PRIMARY EXPERTISE

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

CLIENTS

- Public Service Company of Colorado
- New Mexico Gas Company
- Solarcity
- Canada Pension Plan Investment Board
- North Dakota Public Service Commission

QUALIFICATIONS

- 40-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, load growth, 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.

1 A. Yes, the 2024 IRP summer DLOL scenario in most cases identifies purchasing either
2 capacity contracts and in some cases a wind resource. There is no certainty that the
3 modeled purchase capacity contracts will be available and at what price given the current
4 escalation in generation construction cost and power demands created by data centers.
5 While the combined cycle was only selected in the high load growth scenario, there are
6 no indication that it is a high probability scenario assuming the exclusion of data center
7 load. The 2024 IRP winter DLOL scenario identifies the combustion turbine in most
8 cases with the exception of the New Wind option. Given current cost pressures on CT
9 construction, the existing Project with its interconnection agreement and PTCs is a cost-
10 effective option.

11
12 **Q. Is it reasonable for Montana-Dakota to exercise the purchase option for Badger**
13 **Wind?**

14 A. Yes, subject to a sharing of curtailment risk. Based upon Montana-Dakota's assumption
15 of no curtailment, there are customer benefits to ownership versus either a 20 or 35-year
16 PPA.

17
18 **Q. For the purposes of rate recovery should the PTC benefits be levelized?**

19 A. Yes, I agree with Montana-Dakota's proposal to levelized the benefits of the PTC to
20 stabilize rates.²² Absent levelizing the PTC credits, customers get the full benefit of the
21 PTC over the first ten years but in would have significantly higher costs in years 11 – 20.

22
23 **X. Conclusions and Recommendations**
24

25 **Q. Would you please summarize your conclusions?**

26 A. Yes. The Commission should approve the ADP for Badger Wind based upon the
27 following findings:

²² Direct testimony of Bradley Davison, p 4.

1 economics. Moreover, transmission constraints are dynamic and can shift over time,
2 particularly as more intermittent resources are added to the grid. As a result, projects in
3 congested zones, whether utility-owned or delivered via a PPA, are more exposed to
4 curtailment risk, which can impact their economics.

5
6 **Q. Will Badger Wind have congestion risk?**

7 A. Yes, while the Company's analysis in PU-24-232 suggests that congestion in the
8 Ellendale area decreases due to the added data center load, and that this additional load
9 does not result in significant curtailment of wind generation, which benefits the Project, it
10 is important to note that the load profile could change substantially over the Project's 35-
11 year lifespan. This is particularly true if planned data centers are delayed, scaled back, or
12 do not come online as anticipated. Additionally, the interconnection of new generation
13 resources in the region could alter power flows and exacerbate congestion and
14 curtailment.

15
16 **Q. Will Badger Wind have curtailment risk?**

17 A. Yes, changes in power flows and their resulting impacts on grid congestion and
18 curtailment could significantly affect the generation output of the planned Project. The
19 Project assumes a relatively high-capacity factor (52%). If the resource is curtailed,
20 something not currently modeled or accounted for, the Project's economics would be
21 impacted and may lead to a decline of the benefits of ownership.

22
23 **Q. Are there additional risks associated with ownership versus the PPA?**

24 A. Yes, there are also operating cost risks. The operating cost assumptions include turbine
25 costs, asset management agreement costs, MSA, land lease, property tax, insurance, and
26 levelized recovery of the network integration costs. The Project has secured contractual
27 agreements that provide cost certainty for approximately [TRADE SECRET DATA
28 BEGINS] [REDACTED] [TRADE SECRET DATA ENDS] of O&M expenses during the first
29 [TRADE SECRET DATA BEGINS] [REDACTED] [TRADE SECRET DATA ENDS] years of
30 operations. After that period, when the GE Turbine Service Agreement (TSA) expires,

STATE OF NORTH DAKOTA
PUBLIC SERVICE COMMISSION

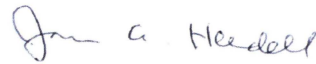
Montana-Dakota Utilities Co.
Advance Prudence – Badger Wind
Application

Case No. PU-25-75

DECLARATION OF JAMES A. HEIDELL

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

Signed on the 10th day of July, 2025 at Denver CO, USA.



James A. Heidell