

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

DIRECT TESTIMONY AND SCHEDULES

JAMES A HEIDELL

STATE OF NORTH DAKOTA
BEFORE THE
NORTH DAKOTA PUBLIC SERVICE COMMISSION

OTTER TAIL POWER COMPANY

ADVANCE DETERMINATION OF PRUDENCE

- ASTORIA NATURAL GAS PROJECT

CASE NO. PU-17-140

- MERRICOURT WIND PROJECT

CASE NO. PU-17-141

CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

- MERRICOURT WIND PROJECT

CASE NO. PU-17-143

DIRECT TESTIMONY JAMES A HEIDELL - 1

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

TABLE OF CONTENTS

I. Introduction and Qualifications 3

II. Summary of Recommendations 5

III. Findings 8

IV. Overview of the Proposed Projects 10

V. Resource Need 15

VI. Review of the Company's Analysis Using the Strategist Model 20

VII. Independent Modeling of the Proposed Resources 32

VIII. Economic Analysis of Astoria 38

IX. Economic Analysis of Merricourt 41

X. Other Issues Considered 46

XI. Recommendations 48

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

I. Introduction and Qualifications

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

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

Q. On whose behalf are you filing this testimony?

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

Q. Please summarize your qualifications and experience.

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

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

A. Yes. I testified on behalf of Montana-Dakota Utilities in the matter of Montana-Dakota Utilities Co., and Otter Tail Corporation; Advance Determination of Prudence, Big Stone II Generating Station Case Nos. PU-06-481 and PU-06-482. I have submitted pre-filed direct testimony on behalf of Advocacy Staff in the Northern States Power Company's

1 request for an Advanced Determination of Prudence (“ADP”) for 1,550 MW of Wind,
2 Case Number PU-17-120.

3
4 **Q. What is the purpose of your testimony?**

5 **A.** The purpose of my testimony is to provide the Commission with my assessment of the
6 Otter Tail Power Company (“OTP” or the “Company”) proposals to construct, own and
7 operate a 250 MW combustion turbine (“CT”) in South Dakota and to own and operate a
8 150 MW wind project in North Dakota. OTP has applied for an ADP for both of these
9 projects (collectively referred to as the “Projects”) as well as a Certificate of Public
10 Convenience and Necessity (“CPCN”) for the North Dakota wind project. I have
11 reviewed the Applications, supporting testimony, and responses to interrogatories in
12 order to develop a recommendation regarding:

- 13 • Whether the proposed Projects are likely to lower electricity costs for OTP’s
14 North Dakota customers;
- 15 • Whether the Projects are needed to meet the capacity and energy needs of the
16 utility’s customers;
- 17 • Whether the Commission should approve the ADPs;
- 18 • Whether conditions should be put on an approval of the ADPs; and
- 19 • Whether the Commission should issue a CPCN for the Merricourt wind project.

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

21
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 ADPs. My analysis is separated into eight sections:

- 26 • A review of the Projects evaluated (Section IV);
- 27 • An assessment of the need for the Projects (Section V);

- 1 • An evaluation of the Company's modeling of the Projects and alternative resource
- 2 expansion options using Strategist (Section VI);
- 3 • My independent analysis of the economics of the proposed Projects and a
- 4 comparison to an option to construct a combined cycle ("CC") plant (Section
- 5 VII);
- 6 • An assessment of the expected energy cost savings of the Astoria CT to the
- 7 Company's North Dakota customers (Section VIII);
- 8 • An assessment of the expected energy cost savings of the Merricourt wind to the
- 9 Company's North Dakota customers (Section IX); and
- 10 • Consideration of additional issues (Section X).

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

12
13 **A. Yes. I am sponsoring the following exhibits:**

- 14 • Exhibit JAH-1: CV of James Heidell;
- 15 • Exhibit JAH-2: Independent Analysis of the Astoria CT project; and
- 16 • Exhibit JAH-3: Independent Analysis of the Merricourt Wind project.

17 **II. Summary of Recommendations**

18
19 **Q. What is your recommendation with regards to approving the Company's**
20 **Application for an ADP to construct and own the 250 MW Astoria CT?**

21
22 **A. My recommendation is that the Commission conditionally approve the Application on the**
23 **basis that the Astoria CT is needed for capacity in part due to the planned retirement of**
24 **the 141 MW of capacity at Hoot Lake in 2021 as well as the expiration of a series of**
25 **short-term power purchase contracts. I evaluated the economic benefits of this project in**
26 **conjunction with a) the request for 150 MW of wind energy and b) the alternative of**
27 **securing both energy and capacity from a new CC project. My evaluation and**

1 conclusions are based upon information presented by the Company, supplemented by my
2 independent analysis.

3
4 **Q. Should this Commission put any conditions on the approval of the ADP for Astoria?**

5
6 **A.** Yes, the project budget is an estimate and a cap should be put on the construction cost of
7 10% over the estimated project costs. This cap corresponds to the high capital cost
8 scenario that OTP ran in conjunction with this application. Therefore, I recommend the
9 following conditions on the approval of the ADP for Astoria:

- 10 • Recovery of the project construction, interconnection, and transmission costs for
11 no more than \$181.5 million excluding AFUDC (10% above the \$165M
12 estimate); and
- 13 • The Company should provide quarterly construction progress reports to the
14 Commission until the Project is in service, indicating the development status of
15 the Project.

16 **Q. What is your recommendation with regard to approving the Company's**
17 **Application for an ADP for the 150 MW Merricourt Wind project?**

18 **A.** My recommendation is that the Commission conditionally approve the Application on the
19 basis that the Merricourt Wind project will contribute to the capacity needed in part due
20 to the planned retirement of the 141 MW of capacity at Hoot Lake in 2021 and the
21 expiration of a series of power purchase contracts. The project will provide energy at a
22 Levelized Cost of Energy ("LCOE") anticipated to be below the Midcontinent
23 Independent System Operator ("MISO") market energy prices. I evaluated the economic
24 benefits of this project in conjunction with a) the request for the 250 MW CT and b) the
25 alternative of securing both energy and capacity from a new CC project. My evaluation
26 and conclusions are based upon information presented by the Company, supplemented by
27 my independent analysis.
28

1 **Q. Should this Commission put any conditions on the approval of the ADP for**
2 **Merricourt?**

3
4 **A.** Yes. My recommendation for approval is based on the conclusion that the wind project
5 will lower electricity costs for OTP's North Dakota customers compared to the
6 alternatives of acquiring a CC project or purchasing electricity from the MISO market. In
7 order for customers to realize these projected savings, it is necessary for the Company to:

- 8 • Secure 100% of the Production Tax Credits ("PTC");
- 9 • Secure interconnection to the MISO grid and firm transmission service within the
10 stated budgets; and
- 11 • Ensure that OTP's construction contractor for Merricourt, EDF, deliver the
12 project on budget.

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

- 15 • The Company's shareholders are responsible for any shortfall as a result of not
16 securing 100% of the PTC rate based upon starting construction in 2016 and
17 completing the Project within the required four-year window;
- 18 • Recovery of the project construction, interconnection, and transmission costs be
19 limited to no more than [Confidential Data Begins] [REDACTED] [Confidential
20 Data Ends].
- 21 • In conjunction with its monthly fuel cost adjustment filings to the Commission,
22 the Company should provide monthly reports of curtailment and negative pricing,
23 including any known reasons for observed curtailment and negative pricing; and
- 24 • The Company should provide quarterly construction progress reports to the
25 Commission until the Project is in service, indicating the development status of
26 the Project.

27 **Q. Should this Commission approve the CPCN for Merricourt?**

1 A. Yes. I recommend approval of the CPCN since the project is needed for capacity, will
2 reduce energy costs for OTP customers, and OTP has the financial and operational
3 capability to: i) oversee EDF's construction of the project, ii) own the project, and iii)
4 operate the project.

5
6 **III. Findings**

7 **Q. Would you please provide a summary of the findings in your testimony that support**
8 **the Commission's approval of the ADP for the Astoria CT?**

9
10 A. Based upon my review and analysis of the testimony filed in the Application, the exhibits
11 contained within the Application, and the information produced in discovery, I conclude
12 the following:

- 13 • Based upon the OTP summer peak demand forecast and existing resources,
14 additional capacity is necessary, to accommodate load growth, replace the
15 retirement of Hoot Lake and expiring short-term capacity contracts;
- 16 • The preliminary estimates of the construction cost is in the range of reported
17 construction costs based upon data collected by the Energy Information
18 Administration ("EIA");
- 19 • The 250 MW Astoria CT is the appropriate type of generation to meet the
20 capacity needs, including consideration that the Company also needs energy and
21 has separately requested an ADP to procure 150 MW of wind; and
- 22 • The estimation of ratepayer benefits conforms to North Dakota requirements to
23 exclude externalities.

24 **Q. Would you please provide a summary of the findings in your testimony that support**
25 **the Commission's approval of the ADP for Merricourt?**

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

- 1 • The Merricourt wind project is anticipated to dispatch into the MISO market at
2 prices that will yield electricity cost savings for North Dakota customers.
3 Resources in MISO are dispatched based upon Short Run Marginal Costs
4 ("SRMC"), subject to constraints on generation units and transmission. With an
5 SRMC of virtually zero, the Merricourt project will typically dispatch ahead of
6 thermal resources and is projected to lower the Company's overall power costs;
- 7 • The levelized cost of the wind project is below the likely alternative market
8 energy and capacity cost. I calculated the estimated savings of the project is
9 approximately \$139M compared to equivalent market purchases of energy and
10 capacity;
- 11 • As a consequence of the Merricourt wind project dispatching into the market at
12 prices lower than the cost of market energy, this translates into OTP reducing its
13 market electricity purchases and overall power costs compared to the base case of
14 not proceeding with the Project. This in turn is forecast to create lower rates for
15 North Dakota customers compared to not proceeding with the Project;
- 16 • Merricourt, while only providing limited capacity, will still contribute to OTP's
17 current and projected capacity deficits;
- 18 • A change in projected market fundamentals, such as very low natural gas prices,
19 could reduce the forecast of savings. However, the savings are not projected to be
20 eliminated even in a very low natural gas price environment; and
- 21 • The estimation of ratepayer benefits conforms to North Dakota requirements to
22 exclude externalities.

22 **Q. Would you please provide a summary of the findings in your testimony that support**
23 **the Commission's approval of the CPCN for Merricourt?**

24 **A. Based upon my review and analysis of the testimony filed in the Application, the exhibits**
25 **contained within the Application, and the information produced in discovery, I conclude**
26 **that the Commission should issue a CPCN for the Merricourt project for the same**
27 **economic reasons that I conclude that the Commission should issue an ADP.**

1 Additionally, I find that OTP has a capacity need and they have the financial and
2 operational capability to oversee the development and construction process of the project,
3 and to then own and operate the project.

4
5 **IV. Overview of the Proposed Projects**

6 **Q. Please provide an overview of the Astoria project.**

7
8 A. The company is proposing to construct a 250 MW natural gas-fired simple cycle CT near
9 Astoria, South Dakota. The Company indicates that it plans to build the facility with
10 quick start capability (typically defined as the ability to start the unit and reach minimum
11 operating levels in ten minutes or less) to help serve both load following and peaking
12 capacity needs. The Company stated that the development site was selected due to its
13 proximity to the Northern Border natural gas pipeline and Big Stone South-Brookings
14 County 345 kV transmission line, which the Company claims will help reduce overall
15 interconnection costs. The Company has stated that it owns the land rights to the parcel
16 on which the proposed project would be located.

17 **Q. What is the status of the Astoria transmission interconnection agreement?**

18
19 A. The project was assigned to the February 2016 study group within MISO's
20 interconnection queue. The interconnection studies for this group began in February 2017
21 with the initial identification of facilities necessary to interconnect Astoria likely to be
22 determined during the summer of 2017. It is expected that a generator interconnection
23 agreement will be completed and executed in 2018.

24 **Q. What is the estimated construction cost for Astoria?**

25
26 A. The estimated total capital costs for the construction of Astoria is \$165 million, or
27 \$665/kW. This includes an estimate of [Confidential Data Begins] [REDACTED]
28 [REDACTED] [Confidential Data Ends] It is important to note that these

1 estimates have been identified by the Company as preliminary.¹ The Company has not
2 selected a turbine manufacturer yet and does not expected to begin the turbine
3 procurement process until the third or fourth quarter of 2018.²

4
5 **Q. What will be the natural gas interconnection for the Astoria CT?**

6 A. The Company plans to supply the CT with a short segment of natural gas pipeline
7 necessary to interconnect to the Northern Border Pipeline. The Company stated in the
8 Application that it chose this location because it offered two significant advantages over
9 other sites considered: 1) the Astoria site required the least amount of combined gas and
10 electric transmission infrastructure, and 2) the Astoria site will provide natural gas supply
11 diversity, as the Company's other natural gas needs are procured via the Great Lakes Gas
12 Transmission Pipeline.

13
14 **Q. Do you agree that the Astoria site offers benefits related to natural gas supply?**

15 A. Yes. Though the site will require a small lateral supply line to the Northern Border
16 Pipeline, this supply line is expected to be less than 1000 feet.³ The Company did
17 consider its existing Solway, MN site; however, the Solway site would require significant
18 electric transmission infrastructure.⁴

19
20 Regarding the natural gas supply diversity benefit, I concur with the Company's
21 argument. While the actual supply of gas will likely come from the same sources
22 (Canadian gas), having the Astoria site be supplied via a separate pipeline provides
23 protection from force majeure events on one of the pipelines.

24
25
26 _____
¹ Swanson Direct p 7 lines 19 - 22

² Response to Case No. PU-17-140 NDPSC 2.6

³ Application Page 4

⁴ Swanson Direct p 6 lines 15-19

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

Q. Will the Astoria CT have an uninterruptible source of fuel?

A. No, the Company plans to take non-firm gas service and it will not be a dual-fuel unit.⁵ However, it is important to recognize that while OTP is a winter peaking utility, MISO Load Resource Zone (LRZ) 1 is summer peaking and therefore there is not the concurrent need for natural gas to handle the LRZ peak load and space heating needs.⁶

Q. Please provide an overview of the Merricourt wind project.

A. The Company is proposing to contract with EDF to construct 150 MW of wind generation near Merricourt, ND. EDF will transfer ownership to OTP following completion of construction. The project will consist of 75 two-megawatt Vestas V110 wind turbine generators and will be located on approximately 13,000 acres. The project is expected to meet the Internal Revenue Service's ("IRS") Safe Harbor requirements for start of construction in 2016 in order to qualify for 100% of the PTC. The project is expected to be in service by the end of 2019 and therefore also meet the four year construction period component of the Safe Harbor requirements.

Q. What is the status of the Merricourt electrical interconnection agreement?

A. The project was assigned to the August 2016 study group within MISO's interconnection queue. The initial identification of facilities necessary to interconnect Merricourt is likely to be determined during the fall of 2017.

Q. What is the estimated construction cost and total LOCE for Merricourt?

⁵ Response to Case No. PU-17-140 NDPS 2.1

⁶ 2016 MISO Independent Load Forecast, Gotham et al, State Utility Forecasting Group, Purdue

1 A. The estimated construction cost for Merricourt is [Confidential Data Begins] [REDACTED]
2 [REDACTED] [Confidential Data Ends], and according the Merricourt's application yields an
3 LCOE of [Confidential Data Begins] [REDACTED] [Confidential Data Ends]. LOCE is
4 an economic assessment of the discounted annual cost to build and operate a power
5 generating asset over its lifetime, divided by the discounted annual energy output of the
6 asset over the same lifetime.

7 Q. How do the proposed CT and wind project impact the Company's capacity mix
8 from a resource diversity perspective?
9

10 A. In 2017, the company's capacity mix is largely made up of coal-fired generation (63%),
11 approximately 8% wind generation, and just over 5% natural gas-fired generation.
12 Adding a 250 MW natural gas CT and a 150 MW wind facility will add resource
13 diversity and flexible generation to the Company's fuel mix, as shown in Table 1.
14

15 **Table 1. OTP MISO Reliable Capacity Mix⁷**

| Resource | 2017 | Percent of OTP Capacity | 2021 ¹ | Percent of OTP Capacity |
|-------------|-------|----------------------------|-------------------|----------------------------|
| Coal | 486.4 | 63% | 369.8 | 45% |
| Natural Gas | 41.9 | 5% | 271.2 | 33% |
| Oil | 54.5 | 7% | 52.5 | 6% |
| Wind | 58.2 | 8% | 81.2 | 10% |
| Hydro | 2.5 | 0% | 2.5 | 0% |
| BTMG | 7.2 | 1% | 7.2 | 1% |
| Purchased | 89.5 | 12% | 9.5 | 1% |

1. Includes Merricourt and Astoria

16
17
18
19
20
21
22
23
24
25
26
27
28 ⁷ 2017 Data from SNL Financial. 2021 data are approximations by: (1) removing 2016 Hoot Lake generation from coal, (2) adding projected Astoria generation to natural gas, (3) adding projected Merricourt generation to renewables, and (4) solving for Market Purchases based upon load forecast.
DIRECT TESTIMONY JAMES A HEIDELL - 13

1
2
3 **Q. How do the proposed CT and wind project impact the Company's energy mix from**
4 **a resource diversity perspective?**

5
6 **A.** The majority of the OTP electricity production will come from coal plants before and
7 after the retirement of Hoot Lake. Even when including the requested Projects, the
8 Company will continue to be dependent on MISO energy market purchases to meet
9 customer loads. Even if the expected load growth does not occur, OTP will be in a net
10 short position, as shown in Table 2.

11 **Table 2. OTP MISO Energy Mix⁸**

| Resource | 2016 MWh | Percent of System | 2021 ¹ MWh | Percent of System |
|----------------------|-----------|-------------------|-----------------------|-------------------|
| Coal | 2,196,015 | 42% | 1,193,451 | 21% |
| Natural Gas | 39,509 | 1% | 376,921 | 7% |
| Oil | 749 | 0% | 749 | 0% |
| Hydro | 25,587 | 0% | 25,587 | 0% |
| Renewables | 491,810 | 9% | 1,158,008 | 20% |
| Net Market Purchases | 2,472,777 | 47% | 2,961,556 | 52% |

1. Includes Merricourt and Astoria

21
22 **Q. What are the implications of the Company increasing its reliance upon intermittent**
23 **resources such as wind generation?**
24
25
26

27 ⁸ 2016 Data from SNL Financial, 2021 data are approximations by: (1) removing 2016 Hoot Lake
28 generation from coal, (2) adding projected Astoria generation to natural gas, (3) adding projected Merricourt
generation to renewables, and (4) solving for Market Purchases based upon load forecast.

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

8 **V. Resource Need**

9
10 **Q. Does OTP have a need for capacity?**

11 A. Yes. In its 2016 IRP, OTP identified a capacity deficit of approximately 22 MW in 2017,
12 growing to a deficit of 273 MW by 2021.⁹ The growing capacity need between 2017 and
13 2021 is primarily driven by a loss of capacity from Hoot Lake and the expiration of a
14 series of short-term capacity contracts. However, 53 MW of increasing load obligation
15 also plays a role in the capacity shortfall.

16
17 **Q. What resources are retiring and contracts are expiring that are creating the
18 additional need for capacity?**

19 A. The capacity need is primarily resulting from the expected retirement of the 141 MW
20 Hoot Lake facility in 2021, as well as expiration of a series of short-term capacity
21 contracts. Note that the capacity purchased through the short-term capacity contracts
22 were made as a partial "bridge" to meet OTP's near-term capacity needs until the time
23 when the Hoot Lake facility retired and a planned new resource would be on line, with
24 the remainder being made up of market purchases.

25
26
27
28 ⁹ 2017-2031 IRP Table 3-8.
DIRECT TESTIMONY JAMES A HEIDELL - 15

1 **Q. Did you review the assumption regarding the retirement of the Hoot Lake Coal**
2 **plant?**

3
4 **A.** Yes. I reviewed a summary of the Company's 2012 Baseload Diversification report that
5 serves as the initial basis for Hoot Lake's retirement. Additionally, I have reviewed the
6 2013 and 2016 IRP modeling assumptions which were used to identify suitable
7 replacements for the Hoot Lake capacity. The assumptions used in these IRPs were
8 developed through a stakeholder process, and I have reviewed them. It is my assessment
9 that these assumptions were reasonable at the time the analyses were conducted.

10 **Q. Have you reviewed OTP's summer peak demand growth projections?**

11
12 **A.** Yes. I reviewed the summer peak load growth assumptions that are part of the
13 2016 IRP and an updated forecast provided by the Company in response to a
14 data request.¹⁰ Within the 2016 IRP, the Company is forecasting a 1.2%
15 average annual growth rate in demand and a slightly higher growth rate in a
16 May 2017 forecast. However, the May 2017 forecast starts at a 53 MW lower
17 demand level. A comparison of the two forecasts is shown in Table 3.

18 **Table 3. OTP Summer Peak Demand Forecast**
19 **[Confidential Data Begins]**

20

| Year | 2016 IRP | | May 2017 Revised Forecast | |
|------|------------------|-----------------|---------------------------|-----------------|
| | Peak Demand (MW) | Demand Growth % | Peak Demand (MW) | Demand Growth % |
| 2017 | | | | |
| 2018 | | | | |
| 2019 | | | | |
| 2020 | | | | |

21
22
23
24
25
26

27
28 ¹⁰ OTP response to NDPSC 2-07
DIRECT TESTIMONY JAMES A HEIDELL - 16

| | | | | |
|------|--|--|--|--|
| 2021 | | | | |
| 2022 | | | | |
| 2023 | | | | |
| 2024 | | | | |
| 2025 | | | | |
| 2026 | | | | |
| 2027 | | | | |
| 2028 | | | | |
| 2029 | | | | |
| 2030 | | | | |
| 2031 | | | | |
| CAGR | | | | |

[Confidential Data Ends]

11 **Q. What is your understanding of the cause for the reduction in peak**
12 **demand?**

14 **A.** My understanding is that the May 2017 forecast may not be as robust as the
15 2016 IRP forecast.¹¹ In addition, the drop in peak demand may be associated
16 with lower expected peak demands associated with pipeline customers.

18 **Q. Does the lower load growth change your perspective on OTP's need for a**
19 **capacity resource?**

20 **A.** No. The IRP identified the projected capacity deficit in 2021 as approximately
21 273 MW. Under the 2017 revised and preliminary load forecast, the capacity
22 deficit is projected to be 230 MW. The Astoria and Merricourt projects will
23 add approximately 266 MW of firm capacity. With the lower preliminary
24 forecast, the demand and supply will be in balance by 2025. Given the
25 lumpiness of investment in generating resources and the uncertainty regarding

26 _____
27
28 ¹¹ OTP response to NDPSC 2.7
DIRECT TESTIMONY JAMES A HEIDELL - 17

1 the load forecast, the potential short-term small surplus for four years is not a
2 serious concern for me.

3
4 **Q. Have you reviewed OTP's load growth projections?**

5 **A.** Yes. I reviewed the load growth assumptions that are part of the 2016 IRP.¹²
6 In the 2016 IRP, the Company is forecasting an 1.2% average annual growth
7 rate in demand, and virtually no average annual growth rate in energy sales
8 over the next fifteen years after incorporating demand side resources. The
9 Company's load forecasts are shown in Table 4.

10
11 **Table 4. OTP Load Forecast**
12 **[Confidential Data Begins]**

13

| Year | Base Load Growth (GWh) | Base Load Growth % | Low Load Growth (GWh) | Low Load Growth % | High Load Growth (GWh) | High Load Growth % |
|------|------------------------------|--------------------------|-----------------------------|-------------------------|------------------------------|--------------------------|
| 2017 | ████ | ████ | ████ | ████ | ████ | ████ |
| 2018 | ████ | ████ | ████ | ████ | ████ | ████ |
| 2019 | ████ | ████ | ████ | ████ | ████ | ████ |
| 2020 | ████ | ████ | ████ | ████ | ████ | ████ |
| 2021 | ████ | ████ | ████ | ████ | ████ | ████ |
| 2022 | ████ | ████ | ████ | ████ | ████ | ████ |
| 2023 | ████ | ████ | ████ | ████ | ████ | ████ |
| 2024 | ████ | ████ | ████ | ████ | ████ | ████ |
| 2025 | ████ | ████ | ████ | ████ | ████ | ████ |
| 2026 | ████ | ████ | ████ | ████ | ████ | ████ |
| 2027 | ████ | ████ | ████ | ████ | ████ | ████ |
| 2028 | ████ | ████ | ████ | ████ | ████ | ████ |
| 2029 | ████ | ████ | ████ | ████ | ████ | ████ |
| 2030 | ████ | ████ | ████ | ████ | ████ | ████ |
| 2031 | ████ | ████ | ████ | ████ | ████ | ████ |

14
15
16
17
18
19
20
21
22
23
24
25

26
27
28 ¹² 2017-2031 IRP Appendix F Figure 8.
DIRECT TESTIMONY JAMES A HEIDELL - 18

| | | | | | | | |
|---|------|--|---|--|---|--|---|
| 1 | CAGR | | ■ | | ■ | | ■ |
|---|------|--|---|--|---|--|---|

2 [Confidential Data Ends]

3
4 **Q. Did you review the three load growth cases?**

5 A. Yes. One aspect of the forecasts that struck me was that the forecasts start with
6 different load assumptions for 2017 (in the range of 6.7% lower and 6.9%
7 higher) and then the load growth rate for each year between the three cases
8 tends to be similar. My hypothesis is that they either used the same underlying
9 macro-economic variables in all three scenarios, or simply applied similar
10 annual growth adjustments.

11
12 **Q. In your opinion, is the overall load forecast reasonable?**

13 A. The load growth appears reasonable based upon past trends and what is
14 happening in the industry. I looked at non-weather adjusted sales from FERC
15 Form 1 and calculated rolling ten year compound average annual growth rates
16 ("CAGR") in order to try to remove some of the weather induced variation in
17 sales. The average of these CAGRs is 0.5% average annual growth. This is
18 shown in Table 5. Industry wide, the trend is for sales growth to be relatively
19 flat except in areas with significant population inflow and employment growth.
20 Therefore, the growth rate for OTP appears reasonable. However, the utility
21 appears to have significant year to year changes in the industrial sales over the
22 past few years and typically this is a group of customers whose loads are not
23 particularly weather sensitive. This may be reflective of the impact of oil prices
24 and pipeline loads but that is a hypothesis based upon the firm demand forecast
25 for the pipeline customers.¹³

26
27
28 ¹³ Pipeline firm demand forecasts provided in response ND-PSC 02-24.

Table 5. OTP Historic Retail Sales Growth (GWh)¹⁴

| Year | Residential | Commercial | Industrial | Other | Total Retail | Load Growth | Rolling 10 Year CAGR |
|------|-------------|------------|------------|-------|--------------|-------------|----------------------|
| 2001 | 1,098 | 1,327 | 1,109 | 71 | 3,606 | | |
| 2002 | 1,131 | 1,389 | 1,101 | 70 | 3,691 | -4.93% | |
| 2003 | 1,142 | 1,383 | 1,121 | 70 | 3,716 | 5.69% | |
| 2004 | 1,119 | 1,385 | 1,198 | 70 | 3,773 | -22.09% | |
| 2005 | 1,163 | 1,429 | 1,233 | 70 | 3,894 | 24.08% | |
| 2006 | 1,171 | 1,453 | 1,298 | 69 | 3,991 | 33.92% | |
| 2007 | 1,218 | 1,519 | 1,318 | 69 | 4,124 | 6.99% | |
| 2008 | 1,258 | 1,559 | 1,357 | 68 | 4,242 | 17.00% | |
| 2009 | 1,297 | 1,594 | 1,285 | 69 | 4,244 | -30.87% | |
| 2010 | 1,273 | 1,590 | 1,331 | 69 | 4,263 | 6.48% | |
| 2011 | 1,316 | 1,596 | 1,311 | 68 | 4,292 | 2.79% | 2.1% |
| 2012 | 1,254 | 1,556 | 1,367 | 65 | 4,241 | -6.07% | 2.0% |
| 2013 | 1,379 | 1,660 | 1,382 | 67 | 4,488 | -2.45% | 1.2% |
| 2014 | 1,386 | 1,689 | 1,551 | 69 | 4,695 | -12.04% | 2.4% |
| 2015 | 1,273 | 1,588 | 1,666 | 67 | 4,594 | -13.92% | -1.3% |
| 2016 | 1,221 | 1,572 | 1,893 | 64 | 4,750 | 5.23% | -3.6% |

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

Q. What resource options were evaluated by OTP?

A. In the preferred plan and sensitivity scenarios, the Strategist model optimized the selection of CCs, CTs, and wind and solar generation. A range of supply side generation options were pre-screened and excluded. These excluded technologies include different coal technologies, nuclear, reciprocating internal combustion engines, and a variety of other renewable technologies. The pre-screening was designed to remove technologies

¹⁴ FERC Form 1 data. Note these are sales data while Table 4 is system load that includes losses and Company use.

1 that would not be least cost and facilitate the model optimizing the resource mix by
2 limiting the number of permutations that would need to be analyzed.

3
4 OTP used the Strategist model to evaluate different configurations and combinations of
5 CT units, CC units, solar generation, and wind generation. The analysis evaluated both
6 248 MW frame and 49 MW aero-derivative CTs, 311 MW CC units, 100 MW utility-
7 scale wind generation projects, and 30 MW utility-scale solar generation projects. Note
8 that while CC options were included in early modeling runs, they were not selected by
9 Strategist in any of the sensitivities. The Company removed the CC option in the final
10 modeling runs to allow for additional wind and solar alternatives.

11 **Q. Did the Company develop and analyze a reasonable set of resource options?**

12
13 **A.** Yes, from a practical perspective, I consider the most likely mix of new resources to
14 include some combination of gas-fired CC plants, gas-fired CTs, wind turbines, and solar
15 generation.

16 **Q. Would you briefly describe how the Strategist model works?**

17
18 **A.** Strategist simulates the operation of electric systems for a given planning period. The
19 model calculates the cost of serving a system's demand and energy requirements
20 incorporating any required capacity reserves. Key model inputs include fuel prices,
21 market electricity prices, and current and potential supply and demand side resources.
22 The model, proceeding one year at a time, simulates the dispatch of the system, though it
23 does not specifically forecast each hour, which is a critical limitation that I discuss below.
24 Moving forward through the planning period, Strategist will determine the point at which
25 new resources are needed to satisfy capacity requirements, and will add various
26 combinations of potential new resources and account for the total system costs (capital
27 plus operating) associated with each combination, or portfolio. At the end of the model
28 run, Strategist produces the least cost portfolio.

1 Q. Do you believe that Strategist has limitations regarding evaluating the economics of
2 adding new resources to the Company's system?

3
4 A. Yes, however, I also note that virtually all modeling approaches have limitations.
5 Strategist has limitations, particularly with respect to the evaluation of wind and solar
6 resources. It uses some hourly information; however, it is not a chronological dispatch
7 model. There are two specific limitations of Strategist related to its ability to properly
8 assess the economics of wind and solar generation. The first limitation is related to
9 Strategist's projections of system resources' operations. Rather than solve for the least-
10 cost amount of generation in each hour to satisfy that hour's projected energy
11 requirement, the model employs what is known as a load duration curve methodology.
12 Load duration curves calculate the amount of time in a given month or a given year that a
13 system requires a certain level of capacity. For example, a load duration curve projects
14 the amount of time a system requires at least 10,000 MW of operating capacity, the
15 amount of time the system requires at least 9,000 MW of operating capacity, and so on.
16 By "stacking" available resources in order of lowest operating cost to highest operating
17 cost and overlaying stack with the load duration curve, the model can quickly estimate
18 the projected operation of each asset until the total system needs are met, beginning with
19 lowest cost resources and incrementally utilizing higher cost resources.

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

27 The second limitation is that Strategist performs a statistical averaging of the energy
28 attributed to non-dispatchable, intermittent resources such as wind generation. Strategist
uses a typical week approach by using a one week sample and repeating that typical week

1 to represent a full month of output. This averaging loses the variability of the maximum
2 and minimum generation of the facility within the month, which again causes the model
3 to understate additional system costs associated with ramping other dispatchable
4 resources to accommodate the intermittent resources.

5 **Q. Given its limitations, do you believe the Strategist analysis is a reasonable indicator**
6 **of the value of adding the proposed resources to the Company's system?**

7
8 A. Yes, when appropriate transmission congestion, market and fuel prices, and other
9 assumptions are incorporated as exogenous model inputs. Even while acknowledging
10 Strategist's shortcomings in accurately representing both hourly system loads and
11 intermittent generation facilities, the Company's analysis demonstrates that the proposed
12 facilities are the least cost mix of resources.

13 **Q. How did the Company evaluate the proposed projects as well as alternative**
14 **resources?**

15
16 A. My understanding is that OTP modeled replacement resource options for Hoot Lake as
17 part of its 2013 IRP. At that time the Company looked at a number of replacement
18 options including a CT (frame and aero-derivative), a CC, and wind. The Strategist model
19 picked the frame CT and CC options with the Preferred Portfolio including a 211 MW
20 frame CT. At that time wind was not in the minimum cost portfolio in part due to the
21 Company modeling the expiration of the PTC. The Company modeled the three resource
22 options as part of the 2016 IRP and incorporated the December 2015 extension of the
23 PTC. In the 2016 IRP, Strategist selected the CT and wind options and the CC was not in
24 the least cost resource expansion mix.

25 **Q. Would you please elaborate on the findings in the 2013 IRP?**

26 A. OTP analyzed options for replacing Hoot Lake and to accommodate potential load
27 growth in the 2013 IRP. In the 2013 analysis, OTP used Strategist to identify the least
28

1 cost additions to meet capacity and energy needs with a combination of gas-fired CCs,
2 three different sized gas-fired CTs, gas-fired combined heat and power, the natural gas
3 conversion of Hoot Lake, wind generation, solar generation, energy efficiency, and
4 demand response. The conclusion from the 2013 IRP was that there was not an
5 immediate need for generation additions; however, a natural gas simple-cycle CT would
6 be needed in either 2019 or 2021. The 2013 IRP further concluded that the specific size,
7 type and timing of the next resource should be more precisely determined in the 2016
8 IRP.

9 **Q. Would you please elaborate on the findings in the 2016 IRP?**

10
11 **A.** The 2016 IRP concluded that the preferred generation expansion plan should include 100
12 MW of wind in 2018, 100 MW of wind in 2020, a new 248 MW CT, and 30 MW of
13 solar. The need for the solar was identified as needed to meet Minnesota's Solar Energy
14 Standard. Inclusion of the solar was not part of the least cost mix selected within
15 Strategist, but it was forced in for compliance purposes.

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

17
18 **A.** Yes. Specifically, I reviewed the following:

- 19 • The results of the planning scenarios the Company conducted via Strategist;
- 20 • The representation of the Company's natural gas and market price projections in
21 the model;
- 22 • The representation of the Company's wholesale electric prices and limits on
23 market purchases to meet the utility's load;
- 24 • The representation of new resource costs; and
- 25 • The representation of each specific Project's cost and operating characteristics in
26 the model.

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

3
4 **A.** Yes. In the 2016 analysis the Company developed 27 scenarios without externalities
5 incorporating variations of the following assumptions:

- 6 • Base, low, and high natural gas prices,
- 7 • Base, low, and high market prices,
- 8 • Base, low, and high load growth,
- 9 • Different pricing of wind and solar, and
- 10 • Different levels of energy efficiency resources.

11 The Company's analysis did not include a least cost expansion plan with a new CC. My
12 understanding is that the CC is not in the expansion plans since it was not chosen by
13 Strategist based upon the model's input assumptions.

14
15 **Q. Do you have any comments on the scenarios the Company used to evaluate the**
16 **Projects?**

17 **A.** I focused on the scenarios that evaluated the economics of changes in natural gas prices
18 in order to evaluate how gas prices impact the relative benefits of the CT & wind
19 combination versus the CC. Based upon my understanding, the OTP scenarios provide
20 limited insight because the market electricity prices were not adjusted to match the
21 change in gas prices.¹⁵ The Company's modeling of the CC with base case gas costs
22 produced similar capacity factors to PA's independent modeling with base case gas costs.
23 The Company modeling of the CC under its low gas cost scenario produced higher
24 capacity factors than PA's independent modeling of low gas costs. In the Company's
25 analysis the CC saved money compared to the Base Case and in the PA analysis the CC

26
27
28 ¹⁵ Case No. PU-17-140 OTP Response to NDPSC-02.4.

1 was the preferred resource in the low gas case. While the two analysis are very different
2 in approach and specific assumptions, they are directionally consistent in regards to
3 identifying an outcome where the CC could be the preferred option.

4
5 **Q. Did you review the representation of the Company's system in the Strategist model?**

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

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

11
12 **Q. What gas price assumptions did OTP evaluate?**

13
14 A. The Company used a base case natural gas forecast based upon a long-run forecast using
15 a January 2016 Wood-Mackenzie forecast (Wood-Mackenzie provides independent
16 natural gas and electricity forecasts to the energy industry.). The Company then looked at
17 scenarios where the gas prices were adjusted +/- 25%, +/- 50% and +100%.¹⁶

18 **Q. Did you review the 2016 Wood-Mackenzie natural gas forecast?**

19
20 A. Yes, I compared it to the gas price forecast developed by PA and used in our market price
21 forecast previously discussed. I also compared the OTP natural gas price forecast to the
22 current Henry Hub forward curve.¹⁷ My conclusion is that while the Wood-Mackenzie
23 forecast is lower than the PA forecast for the early years of the forecast, it is nonetheless
24 reasonable. Figure 1 below provides my comparison.

25
26
27
28 ¹⁶ 2017 – 2031 IRP Appendix F p 4.

¹⁷ OTC Global Holdings Forwards as of 7/31/2017

1 **Figure 1. Natural Gas Price Forecast Comparisons**
2 **[Confidential Data Begins]**
3
4
5
6
7
8
9
10
11
12

13 **[Confidential Data Ends]**
14

15 **Q. Are MISO wholesale electric prices an input or an output to the Strategist Model?**
16

17 A. They are an input. The model incorporates wholesale market purchases as one option
18 available to meet the OTP load along with the OTP generation resources. The Company
19 used the base case wholesale electricity price forecast dated January 2016 and developed
20 by Wood-Mackenzie. The company analyzed scenarios with low and high market energy
21 prices by adjusting the prices +/- 25%.

22 **Q. Did you review the 2016 base case forecast of wholesale electric prices?**
23

24 A. Yes, I compared the near term prices to the forward prices for Minnesota Hub and I
25 compared the long term to the forecast developed by PA as part of the Company's
26 Strategist modeling review described in Section VI of my testimony.
27
28

1 **Q. Does the Company's analysis incorporate a reasonable set of market prices?**

2

3 **A.** Generally yes. Figures 2 and 3 below provide a comparison of the On- and Off-Peak
4 pricing forecasts. While the Wood-Mackenzie forecasts do increase significantly relative
5 to the PA forecast in the later years, I did note that the On-peak Wood-Mackenzie price
6 forecast is lower than the PA forecast in the 2018-2028 timeframe. To account for the
7 potential variance in actual prices relative to the forecasts used in the analysis, I evaluated
8 the projects under a range of prices, as described below in Section VII.

8

9 **Figure 2. Wholesale Electric On-Peak Price Forecast Comparisons**

10 **[Confidential Data Begins]**

11

12

13

14

15

16

17

18

19

20

21

22

23

24

25

26

27

28

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

[Confidential Data Ends]

Q. Did you look at the implied heat rates implied by the PA and Wood-Mackenzie gas and market electricity price analyses?

A. Yes, I looked at the implied market heat rates based upon: i) forward electricity and natural gas prices, ii) PA's forecast of electricity and natural gas prices, and iii) the Wood-Mackenzie forecasts of electricity and natural gas prices. Figure 4 is a comparison of the three forecasts of future heat rates. Because the region has a high reliance on coal, higher gas costs tend to produce market heat rates which are very similar to the base case gas costs, so on Figure 4, the high gas costs heat rates are largely "hidden" behind the base case curve. The higher market heat rate forecast used by OTP suggests that a new CC or CT is likely to have a relatively high capacity factor in the Strategist model since the CC and CT will tend to be a lower cost resource than the market for meeting the OTP load.

Figure 4. Comparison of Market Heat Rate Forecasts

[Confidential Data Begins]

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

[Confidential Data Ends]

Q. Did you review the Company's load forecast?

A. Yes, I discussed this in Section V of my testimony in the discussion of the need for new resources.

Q. Did you review the assumptions for the cost of new resources?

A. Yes, I reviewed the costs for the primary replacement options (CT, CC, and wind units) by comparing the cost assumptions with a recent EIA analysis of 2015 construction costs based upon the EIA-860 report and wind construction costs based upon a National Renewable Energy Laboratory ("NREL") study¹⁸. A comparison of new resource costs is

¹⁸ 2015 Cost of Wind Energy Review, Mone et al, National Renewable Energy Laboratory, March 2017

1 shown in Table 6. The costs used by OTP are similar to studies of 2015 construction
2 costs.¹⁹

3
4 **Table 6. Review of New Build Capital Cost Assumptions**

5 **[Confidential Data Begins]**

6

| Construction Cost (\$2017 \$/kW) | OTP | EIA/NREL |
|----------------------------------|-----|----------|
| CC | ■ | ■ |
| CT-Frame | ■ | ■ |
| CT-Aero | ■ | ■ |
| Wind | ■ | ■ |

7
8
9
10 **[Confidential Data Ends]**

11
12 **Q. Did you review the Company's representation of the Projects in the Strategist**
13 **model?**

14
15 **A.** Yes. I reviewed the individual Projects' revenue requirements for both the Astoria and
16 Merricourt projects as well as the assumptions for the CC units. I also reviewed projected
17 generation for all Projects.

18 **Q. What did you conclude regarding the Company's representation of the Projects and**
19 **input assumptions in the Strategist model?**

20
21 **A.** I found the representation of the projects' attributes reasonable and the inputs related to
22 market prices, loads, and natural gas prices consistent with the assumptions in the IRP. I
23 previously discussed the specific inputs and concluded that they are reasonable
24 assumptions, given the caveat that these are only assumptions and long term prices will
25 likely deviate significantly from the assumptions.

26
27
28 ¹⁹ U.S. Energy Information Administration, Form EIA-860, Electric Generator Construction Costs

1
2 **Q. What did you conclude regarding the representation of the Company's system in the**
3 **Strategist model?**

4
5 A. I believe the Company's financial assumptions such as the Weighted Average Cost of
6 Capital ("WACC"), inflation rate, and tax assumptions are consistent with those
7 assumptions identified in the Company's Application and the 2017 Integrated Resource
8 Plan.

9 **VII. Independent Modeling of the Proposed Resources**

10
11 **Q. Did you prepare an independent assessment of the relative economics of adding**
12 **wind, CTs, and / or CC units?**

13 A. Yes. I used an hourly production cost model of the MISO market to develop an
14 independent view of wholesale electricity prices in MISO and the economics of the 250
15 MW CT, 150 MW wind project, and a 311 MW CC. The result of my analysis is that
16 acquiring an asset is a lower cost alternative to meeting OTP's load requirements with
17 market purchases. I also determined that the wind / CT option is a lower cost resource
18 expansion plan than the CC unit for the base case as well as the high gas cost case that I
19 prepared.

20
21 **Q. How will the generators earn revenues in the MISO market?**

22 A. OTP's generators earn revenues based upon dispatching into the MISO market. The
23 market clearing price will reflect congestion and losses allocated to each generator's
24 interconnection node. In most hours, wind units are essentially price takers since they
25 have little to no SRMC - with the exception of the PTC, which incents them to generate
26 even if market prices are negative.

1 The same concept is true for the Company's thermal generation - if the SRMC of the
2 generators is below the market price, then in most instances the generators should be
3 dispatched. Hourly production cost models mimic this dispatch logic to determine the
4 market clearing price and operational and financial performance of each generation unit.

5
6 **Q. Would you please explain your reference to an hourly production model?**

7 **A.** Yes. I used the EPIS AURORAxmp model, which is an hourly chronological dispatch
8 model. The model simulates the dispatch of the MISO system at an hourly level and
9 dispatches available generation to meet the hourly load subject to the constraints
10 associated with individual generation units and transmission capabilities between
11 generators and load centers. The model identifies the marginal unit needed to meet the
12 load and the SRMC of that unit sets the hourly market clearing price. All generators that
13 are dispatched and also have a lower cost than the marginal unit earn infra-marginal
14 revenues.

15
16 **Q. Would you please explain how you used the AURORAxmp model to analyze the
17 OTP resource options?**

18 **A.** Yes, the Merricourt, Astoria, and generic CC units were included in our model's database
19 of generation plants. These resources are then available to be dispatched to meet the
20 MISO load subject to generator and transmission constraints. The AURORAxmp model
21 calculates hourly energy prices for different hubs on the MISO system as well as
22 projecting the dispatch of each generation unit. However, I used a second model, PA's
23 internally developed Asset Dispatch Model, to separately estimate the dispatch and
24 associated revenues, fuel costs, and non-fuel Variable Operations and Maintenance
25 ("VOM") for the gas-fired units. The wind unit is assumed to dispatch according to the
26 hourly portfolio entered into the model and the revenues for the wind unit are the hourly
27 dispatch times the hourly price of electricity. Annual values for capacity reflect the
28 fundamental value of capacity to the MISO market based on the market's overall supply-
demand balance.

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

Q. How did you calculate the gross margins for the CC and CT?

A. I used PA's Asset Dispatch Model that uses PA's monthly on and off-peak price forecast and historic hourly price patterns to shape the monthly on and off-peak prices. This superimposition of hourly price patterns on the monthly prices creates more variation in hourly prices than what typically comes out of an hourly production cost model. The CT and CC were then dispatched against the hourly prices to calculate starts, run hours, generation, fuel usage & costs, VOM, and market revenues.

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

A. The Company pays the MISO market price for power to serve its customers, and offsets these costs with revenues it earns by dispatching its generation into the MISO market. In an idealized world where its generation exactly matches its load, the costs to its customers would be the costs of that generation. However, there are additional factors which impact the costs. First, because of net sales and net purchases, there are potentially either excess revenues to further offset the costs of serving the load, or, in OTP's case, there is a deficiency in power sales revenues.

Second, there are typically congestion costs and transmission losses for a generator's interconnection point. This impacts the revenues the generators earn. Because OTP purchases load from MISO at a different node, or pricing point, than the generators, these costs and losses can impact the total projected savings for OTP's customers.

Q. Did you evaluate congestion and losses associated with the proposed generation projects?

1 A. Yes, I reviewed 2015 and 2016 historical hourly LMPs to evaluate the price differentials
2 between the OTP load node (OTP.OTP) and the proxy nodes for the project sites. This
3 analysis indicated that the combination of congestion and losses was typically \$0 - \$5 /
4 MWh below the OTP load withdrawal node. This analysis is shown in Table 7. I
5 recognize that this analysis does not incorporate either the change in congestion as a
6 result of locating new generation in the area, or the impacts of any transmission upgrades
7 that may be required by MISO.

9 **Table 7. Historic LMP Differentials**

| Range of LMP Basis to OTP Load Node (\$/MWh) | Number of Hours with Basis Price in Indicated Range | | Cumulative Percentage of Hours with Prices in/below indicated Basis Range | |
|--|---|---------|---|---------|
| | Kerncourt | Astoria | Kerncourt | Astoria |
| <-50 | 1 | 2 | 0.0% | 0.0% |
| -50--45 | - | 1 | 0.0% | 0.0% |
| -45--40 | - | - | 0.0% | 0.0% |
| -40--35 | - | 4 | 0.0% | 0.0% |
| -35--30 | 3 | 1 | 0.0% | 0.0% |
| -30--25 | 8 | 9 | 0.1% | 0.1% |
| -25--20 | 16 | 20 | 0.2% | 0.2% |
| -20--15 | 35 | 73 | 0.4% | 0.6% |
| -15--10 | 85 | 191 | 0.8% | 1.7% |
| -10--5 | 345 | 919 | 2.8% | 7.0% |
| -5-0 | 15356 | 12745 | 90.3% | 79.6% |
| 0-5 | 1567 | 3422 | 99.3% | 99.1% |
| 5-10 | 105 | 141 | 99.9% | 99.9% |
| 10-15 | 16 | 7 | 100.0% | 99.9% |
| 15-20 | 5 | 7 | 100.0% | 100.0% |
| 20-25 | 2 | 2 | 100.0% | 100.0% |

1. Day ahead data from 1/1/2015 to 12/31/2016, obtained from Energy Velocity

23 **Q. How does the PA market price forecast compare with forward electric prices?**

24
25 A. I discussed this previously in Section VI above.

26
27 **Q. Did you analyze the proposed resources under different scenarios?**

1 A. Yes, I also evaluated the projects under low and high gas price scenarios. The low gas
2 price scenario uses the forward Henry Hub gas prices through 2029 then holds the 2029
3 gas price flat on a real dollar basis. The high gas price assumes gas prices one dollar
4 higher than the base case forecast starting in 2023. Beginning in 2019, the high gas
5 forecast begins to trend toward the one dollar increase, culminating in the full one dollar
6 increase by 2023.

7 **Q. How did you evaluate whether each of the projects is cost effective?**

8
9 A. I developed models to estimate the total revenue requirements for each asset and I
10 compared those costs to the revenues that each asset is forecast to earn in the market.²⁰
11 The market revenues for each project are the same as what it would cost to buy the same
12 amount of electricity and capacity from MISO but for the construction of the generation
13 units. The corollary to that assumption is that adding these units to the market either do
14 not change the market prices, or someone else will build similar units. I made the
15 comparison of the Projects' revenue requirements to the projected market revenues on a
16 NPV basis, using the Company's capital structure and cost of capital. The results of this
17 analysis are shown in Table 8. From my analysis I conclude that for the Projects and the
18 proxy CC, the units are lower cost than buying energy and capacity from the market.
19 However, this table cannot be used to determine if the CC is the lower cost alternative to
20 the CT / wind combination because the assets provide different amounts of energy and
21 capacity, and have different assumed operating lives. In order to make the comparison I
22 evaluated the LCOE of the Projects.

23 **Table 8. NPV of Project Revenue Requirements vs. Market Revenues (\$000)**

24 **[Confidential Data Begins]**

| | Merricourt | Astoria | CC Option |
|--|------------|---------|-----------|
|--|------------|---------|-----------|

25
26
27
28 ²⁰ The revenue requirement includes fuel and non-fuel operating expenses, recovery of capital
(depreciation expense), and return on rate base.

Public Document
Trade Secret Data Excised

| | Revenue Requirements | Market Revenues | Revenue Requirements | Market Revenues | Revenue Requirements | Market Revenues |
|----------------------|----------------------|-----------------|----------------------|-----------------|----------------------|-----------------|
| Base Case | | | | | | |
| High Gas Case | | | | | | |
| Low Gas Case | | | | | | |

[Confidential Data Ends]

Q. How did you evaluate whether the CT / Wind combination is lower cost to rate payers than a CC?

A. I compared the LCOE of Astoria & Merricourt compared to the proxy CC unit for the three cases that I modeled. In order to make the two options more comparable on an LCOE basis, I added additional capacity costs to the Astoria & Merricourt combination so that it provides an equivalent amount of capacity as the CC unit. The results of this analysis are shown in Table 9.

Table 9. Project LCOE Comparisons (\$/MWh)

[Confidential Data Begins]

| | Astoria/Merricourt | CC Option |
|----------------------|--------------------|-----------|
| Base Case | | |
| High Gas Case | | |
| Low Gas Case | | |

[Confidential Data Ends]

The Astoria/Merricourt combination is lower cost than the CC in the base and high gas cases. While it is a higher cost option in the low gas case, I still recommend the approval of the ADPs for Astoria and Merricourt. The reason for this is that while I believe it is informative to consider a low gas case environment, the Astoria/Merricourt costs are significantly lower than the CC under the base case conditions. While there are no perfect forecasts of what gas costs will be for the next twenty five years, my judgement is that the forward strip, used for the base case, is an optimistic view given that the fundamental

1 forecasts of PA and others indicate that future gas prices will be higher based upon
2 extraction costs and balancing of supply and demand. In addition, the CC's projected
3 high capacity factor in the low gas cost case contributes to the lower LCOE of the CC. In
4 reality, there may be other factors such as more penetration of solar and wind which will
5 depress the CC capacity forecast below the forecast. With a complex decision such as
6 this, one is often faced with the reality that one option is not clearly dominant in all cases.
7 The Commission must consider the relative risks of the projects across all scenarios.
8 When evaluating the projects, I conclude that the Astoria/Merricourt projects are likely to
9 offer the best value for North Dakota customers, even though they may not be least cost
10 under every scenario.

11 **Q. Is the result of your analysis consistent with the OTP Strategist analysis?**

12
13 A. The results are consistent in that the combined CT and wind option is a lower cost option
14 than the CC, and the conclusion that the Projects save rate payers money compared to
15 market purchases. The results of both the Company's and my analysis are discussed
16 further in the next section.

17 **VIII. Economic Analysis of Astoria**

18
19 **Q. Would you please provide an overview of your analysis of the Astoria CT project?**

20
21 A. Yes, my analysis of the economics of the Astoria project builds upon my projections of
22 the generators' gross margins described in Section VII and the analysis developed by
23 OTP in the Strategist model described in Section VI. In Section VII, I utilized the two
24 different approaches (PA and OTP) to forecast gross margins, and incorporated fixed
25 operating costs and other costs to evaluate the LCOE of the Astoria project in order to
26 identify savings compared to market purchases and the relative economics of a combined
27 wind and CT expansion option versus a CC unit.
28

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

3
4 **A.** Yes, I calculated the NPV of the forecast energy and capacity revenue and compared that
5 with a calculation of revenue requirements based upon both the Strategist and the Aurora
6 analysis. This calculation is shown in Exhibit JAH-2.

7 **Q. What are the estimated savings?**

8
9 **A.** The estimated net present value of savings for the PA base case is \$182 million in my
10 analysis and approximately \$36M in the Strategist analysis²¹. I believe that one of the
11 reasons the numbers are different is that I calculated the savings relative to selling into
12 the wholesale market while the Strategist calculation is compared to the base case
13 assumption about the supply mix.

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

15
16 **A.** Yes. When natural gas-fired generation units are the marginal units setting market prices,
17 there is a strong relationship between gas prices and power prices. The MISO Market
18 Monitor reports that over the last 13 months, the correlation coefficient between the
19 Henry Hub natural gas price and the MISO RT LMP was almost a 0.77.²²

20
21 **Q. Did the Company use different market electricity prices in their different gas price**
22 **scenarios?**

23
24
25
26
27 ²¹ Strategist Savings estimate in OTP Astoria Application p 15.

28 ²² MISO May 2017 Monthly Market Assessment Report, Market Evaluation and Design, July 13,
2017, p 17.

1 A. No, the Company appears to have used a single market price forecast for the different gas
2 price scenarios and the company separately modeled scenarios with changes in gas prices
3 and changes in market electricity prices.²³ This can potentially distort the Strategist
4 results when the model evaluates whether to dispatch generation units in the model or
5 purchase from the market to meet the load profile.

6 **Q. Did you estimate how the revenues from the Astoria project change under different**
7 **market gas price scenarios?**

9 A. Yes. In addition to the base case, I evaluated Astoria using a high and low gas price
10 scenario. The gas price forecasts also result in changes in the forecast of wholesale
11 energy prices.

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

14 A. The results are shown below in Table 10.

15
16
17 **Table 10. Astoria Savings Utilizing PA Scenarios**

18

| Scenario | Estimated Savings \$ (Millions) | % Change in Savings | Description |
|------------------------|------------------------------------|------------------------|-------------------------------|
| Base Case | 182 | | |
| High Gas Case | 201 | 10% | PA gas forecast + \$1 |
| Low Gas Case | 193 | 6% | NYMEX forward gas prices |
| High Capital Cost Case | 180 | -1% | 10% Higher Construction Costs |

19
20
21
22

23 **Q. Is it likely that market energy and capacity prices will decrease to the point where**
24 **the Astoria CT will not be economic?**

25
26
27
28

²³ See OTP response to NDPSC Case No: PU-17-140 2.4
DIRECT TESTIMONY JAMES A HEIDELL - 40

1 A. I do not think it is likely, at least in the near term. The efficient CT is the proxy for the
2 lowest cost of capacity in the current electricity markets, if the project is built on budget
3 then the project costs are comparable to what another party would have to pay to secure
4 the same capacity and energy. Of course, there are factors that could lead to the project
5 not recovering its full costs. These factors include an over-supply of generation capacity
6 and new technology that provides equivalent amounts of capacity and energy at a lower
7 price.

8 **IX. Economic Analysis of Merricourt**

9
10 **Q. Would you please provide an overview of your analysis of the Merricourt project?**

11
12 A. Yes, my analysis of the economics of Merricourt is structured the same as for Astoria. I
13 used the projections of the generators gross margins described in Section VII and the
14 analysis of gross margins calculated by OTP in the Strategist model described in Section
15 VI. I evaluated the two forecast of gross margins and incorporate fixed operating costs
16 and other costs to evaluate the LCOE of the project in order to identify savings.

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

19
20 A. Yes. I calculated the market revenues based upon the hourly production profile of the
21 project summed into on- and off-peak generation by month, and multiplied by the on- and
22 off-peak MISO forecast of Minnesota Hub prices provided by the Company with an
23 associated adjustment for congestion. I included capacity revenues based upon the PA
24 forecast of capacity prices. I then subtracted the estimates for renewable intermittent
25 integration and an estimate of coal plant cycling costs.²⁴ I then calculated the annual
26

27
28 ²⁴ Estimates based upon Northern States Power Company Advance Prudence – 1,550 MW Wind
Portfolio Application, Martin Direct Testimony, Table 4, p 50. Exhibit __ (PJM-1)
DIRECT TESTIMONY JAMES A HEIDELL - 41

1 savings based upon the revenue requirements I projected for the Merricourt project. This
2 calculation is shown in Exhibit JAH-3.

3
4 **Q. Did you review the Company's economic analysis of the LCOE of the wind project
5 and the estimated savings to ratepayers?**

6 A. Yes, I reviewed the Strategist results provided by the Company as well as the ratepayer
7 savings analysis that is summarized from the Strategist model runs. My conclusion is that
8 the reported LCOE are consistent with the models. Of course, these results are based
9 upon a number of critical assumptions. I previously discussed the assumptions related to
10 natural gas costs, wholesale market power prices, and congestion costs.

11 **Q. Did you consider curtailment risk for output from Merricourt?**

12
13 A. Yes, I reviewed the March 31, 2017 study prepared by Siemens for OTP that analyzed
14 the potential for curtailment risk using the PROMOD model. The study identified some
15 cases with curtailments that could be eliminated with [Confidential Data Begins] [REDACTED]
16 [REDACTED] [Confidential Data Ends] This
17 could presumably be accommodated within the cost sharing arrangements with EDF and/
18 or out of project contingencies.²⁵ In addition, since the congestion is also associated with
19 the Foxtail wind project there is likely to some type of cost allocation assuming that
20 MISO identifies the need for an upgrade.

21 **Q. Does the LCOE and revenue requirements model include wind farm
22 decommissioning costs?**

23
24 A. I do not believe the Company included decommissioning costs in its analysis.
25

26
27
28 ²⁵ Case No. PU-17-141 OTP Response to NDPSC-02.1 Attachment 1 p A-1
DIRECT TESTIMONY JAMES A HEIDELL - 42

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

3
4 A. No. I assume a cost of \$50,000 (real) per turbine at the end of the 25-year period as the
5 decommissioning cost, net of salvage value. This increases the LCOE of the Projects on
6 the order of \$1.20/MWh.²⁶

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

9
10 A. Yes, the discount rate is appropriate. The Company appears to have used a range of
11 discount rates from [Confidential data Begins] [Confidential Data
12 Ends] in the levelized cost calculations.²⁷ The discount rate is based upon the capital
13 structure and return assumptions in Table 11.

14
15 **Table 11. Cost of Capital Assumptions**
16 [Confidential Data Begins]

17

| Component | Structure | Return | Before Tax WACC |
|---------------|-----------|--------|-----------------|
| L-T Debt | | | |
| Common Equity | | | |
| Preferred | | | |
| Total | | | |

18
19

20 [Confidential Data Ends]

21 The OTP Return on Equity (ROE) assumption is slightly above the average ROE of 9.77
22 percent awarded in 42 electric rate cases in 2016.²⁸

23
24
25
26 ²⁶ Decommissioning cost estimate based upon the New York Black Oak Wind Farm
Decommissioning Plan.

27 ²⁷ Case No. PU-17-141 Attachments 1 and 3 to IR NDPSC-02.3

28 ²⁸ SNL Rate Case Statistics, <https://www.snl.com/interactivex/RateStatistics>. According to SNL
Rate Case Statistics the MNPUC authorized a ROE of 9.72% in the last rate case.

1 **Q. How is the capacity of the wind project valued in the economic analysis?**

2
3 **A.** OTP assumed the accredited capacity based upon 15.6% of nameplate capacity. The
4 Company used a third party forecast of MISO capacity prices in the Strategist analysis.

5
6 **Q. Does the economic analysis include any assumption regarding wind integration
7 costs?**

8 **A.** OTP indicated that they included an assumption for wind integration costs in their
9 Strategist modeling. They did not include an estimate of wind congestion costs.

10
11 **Q. Did you evaluate the impact of changes in production as a result of curtailment or
12 deviations from expected performance?**

13
14 **A.** Yes. I calculated the market revenues at a five percent reduction in output. In this
15 analysis I assumed that the operating costs for the turbine did not change. The 5%
16 reduction in output increased the LCOE by \$2.20 / MWh.

17 **Q. Is it reasonable to assume that the plant will have below average electricity
18 production in every year?**

19
20 **A.** It is unlikely that the winds will be below average in every year. However, issues with the
21 turbines or the forecast of wind production could result in the average annual production
22 being below the Company's P50 assumption.

23
24 **Q. Did you review the O&M cost assumptions incorporated into the estimate of
25 savings?**

26 **A.** Yes. I reviewed the costs for each Project and the CC and compared those costs to
27 average costs reported in a 2016 NREL study, estimates developed by Black & Veatch,
28

1 and EIA data.²⁹ A summary of the O&M costs is shown below in Table 12. Given the
2 range of costs estimates and differences in how operating costs are characterized, I have
3 concluded that the OTP IRP assumptions are in the range of reasonableness.

4
5 **Table 12. Summary of O&M costs**
6 **[Confidential Data Starts]**

7

| Generation Type | Non Fuel VOM (\$/MWh) | | FOM (\$/kW) | |
|-------------------|-----------------------|-----------|-------------|-----------|
| | OTP | EIA / B&V | OTP | EIA / B&V |
| 8 Wind | | | | |
| 9 Frame CT | | | | |
| CC | | | | |

10 **[Confidential Data Ends]**

11
12 **Q. Does the economic analysis include any valuation of environmental or economic**
13 **development benefits?**

14 **A.** No, neither environmental nor economic development benefits are incorporated into the
15 estimated savings to ratepayers or levelized cost analysis. My understanding is that
16 exclusion of these two items is consistent with North Dakota statute.³¹

17
18 **Q. Did the Company accept the lowest cost wind project?**

19
20 **A.** Yes, it appears so. While there was no independent market monitor overseeing the bid
21 review process, the Company provided a summary of six other bids that it had received.
22 The bids included both PPAs with a variety of pricing structures and BOT projects.³²

23
24
25
26 ²⁹ 2015 Cost of Wind Energy Review, Mone, Hand, et al., National Renewable Energy
Laboratory, March 2017, Table 8.2 Cost and Performance Characteristics of New Generating Technologies, Annual
Energy Outlook 2017, U.S. Energy Information Administration, January 2017

27 ³⁰ OTP estimates of FOM vary by year

28 ³¹ See N.D.C.C. § 49-02-23.

³² Case No. PU-17-141 Attachment 1 NDPSC-02.23

1 **X. Other Issues Considered**

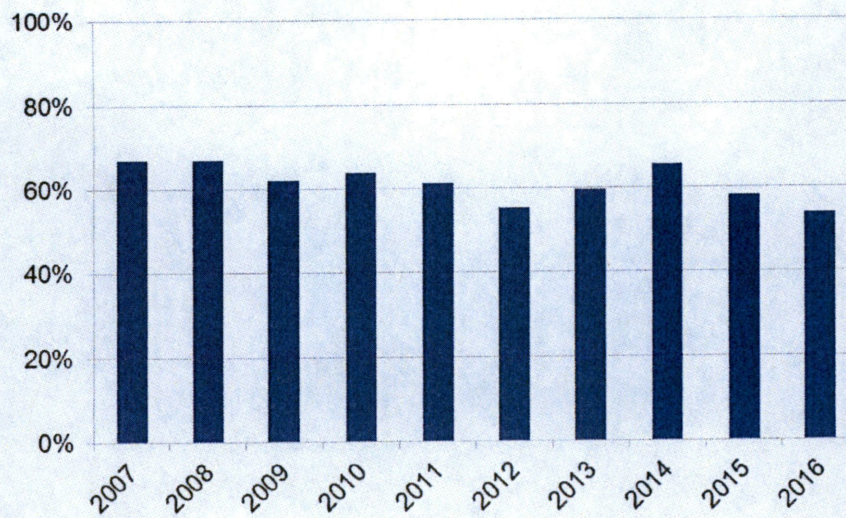
2
3 **Q. Will the Merricourt project increase the cost of power from coal generation in**
4 **North Dakota or for OTP's coal plants?**

5 **A.** Yes. It is likely that these Projects will contribute to the increased cost of coal generation
6 on a dollar per MWh basis. However, it is difficult to quantify what the specific impact of
7 these Projects will be. Collectively, Minnesota, North Dakota, South Dakota, and
8 Wisconsin have added over 5.8 GW of wind projects in the last decade, and there is an
9 additional 3.8 GW of proposed and permitted wind projects in MISO.³³ These projects
10 collectively contribute to a need for coal plants to cycle more, operate less efficiently, and
11 spread fixed costs over fewer MWh generated. As shown in Figure 5, the average
12 capacity factor of MISO coal plants has been in decline over the past decade, with the
13 exception of an increase in part attributed to the Polar Vortex (an extended, extreme cold
14 weather event which occurred in December 2013 – January 2014).
15
16
17
18
19
20
21
22
23
24
25

26
27
28

³³ Energy Velocity

Figure 5. MISO Coal Plants Aggregate Capacity Factor³⁴



1
2
3
4
5
6
7
8
9
10
11
12
13 **Q. Did the Company provided an estimate of the increased cost to coal plants?**

14 **A.** No. However, I reviewed the 2016 study on the impact of wind and solar on the cost of
15 coal plant cycling in the Public Service Company of Colorado (an Xcel Energy
16 subsidiary) system. The scenario with the largest amount of wind added in the northern
17 Colorado region was limited to 900 MW, and the conclusion of the study is that the
18 levelized cycling cost is \$1.14/MWh.³⁵ I also reviewed a 2013 NREL study of the impact
19 of wind and solar on coal plant cycling in the west, and the high cost scenario estimated a
20 cycling cost of \$1.28/MWh.³⁶ Based upon these two studies, I conclude that \$1.48/MWh
21 is a reasonably conservative assumption.
22
23

24
25
26 ³⁴ Source: SNL

³⁵ Wind and Solar-Induced Coal Plant Cycling and Curtailment Costs on the Public Service
Company of Colorado System, Xcel Energy Services, Inc., May 13, 2016.

27 ³⁶ The Western Wind and Solar Integration Study Phase 2: Executive Summary, Lew & Brinkman,
National Renewable Energy Laboratory, NREL/TP-5500-58798, September, 2013
28 <https://www.nrel.gov/grid/wwsis.html>

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

3
4 **A.** No, it is not included in the OTP analysis. However, I included it in my analysis.

5
6 **Q. If the Commission rejects the ADP, will the increased coal plant cycling cost be**
7 **avoided?**

8 **A.** I do not believe so. There is a large amount of wind that is targeted for construction in
9 MISO which will also impact the operation of the Big Stone and Coyote coal plants.
10

11 **XI. Recommendations**

12 **Q. Should the Commission grant an ADP for the Merricourt wind project?**

13
14 **A.** Yes, although I recommend that the ADP include the following qualifications:

- 15 • North Dakota ratepayers should not have to pay any additional costs if the Company
16 fails to get the full PTC;
- 17 • Recovery of wind Project construction, interconnection, and transmission costs for
18 the project should be limited to no more than [Confidential Data Begins] [REDACTED]
19 [REDACTED] [Confidential Data Ends], excluding AFUDC. This is approximately 6%
20 higher than the state project cost including contingencies and reflects the additional
21 estimate of contingencies identified in the application³⁷;
- 22 • In conjunction with the monthly fuel cost adjustment filings to the Commission, the
23 Company should provide monthly reports of curtailment and negative pricing
24 observations at the Project, and any know reasons for observed curtailment and
25 negative pricing; and

26
27
28

³⁷ PU-17-141 & PU-17-143 Application for ADP and CPN p 7.
DIRECT TESTIMONY JAMES A HEIDELL - 48

- 1 • The Company should provide quarterly construction progress reports until the
2 Merricourt project is in service, indicating the development status of the project.

3
4 **Q. What are the economic consequences if the Company does not meet the safe harbor**
5 **requirements for starting construction in 2016 and or meets the target but does not**
6 **meet the four-year completion requirement under the Continuous Construction**
7 **Test?**

8 **A.** In the extreme, if the Projects do not qualify for the PTC, the LCOE increases by
9 approximately 170 percent.

10
11 **Q. Why should Company shareholders absorb the full risk of not qualifying for the full**
12 **PTC?**

13 **A.** The Company's analysis has identified wind as cost effective when the LCOE is below
14 \$30 / MWh. Without the PTC the costs will be over that threshold. The Company has
15 also stated that [Confidential Data Begins] [REDACTED]
16 [REDACTED]
17 [REDACTED]
18 [REDACTED]
19 [REDACTED]
20 [REDACTED]³⁸ [Confidential Data Ends] I have not been able to
21 replicate the analysis that customers will be no worse off if the Company proceeds past
22 closing of the Asset Purchase Agreement and subsequently does not qualify for the full
23 PTCs. Ultimately, the Project could potentially be cost effective if the full PTC benefit is
24 not received. However, that assessment should be made once the facts are known about
25 the final costs of the project and level of tax benefits. It is my expectation that OTP will

26
27
28 ³⁸ OTP response to Case No. PU-17-141 NDPSC 2.14 Attachment 1.
DIRECT TESTIMONY JAMES A HEIDELL - 49

1 receive the full PTC credit. However, I believe it is important to address an unlikely
2 contingency.

3
4 **Q. Why are you recommending that the Company bear the risk of cost overruns
5 related to the project's construction and transmission interconnection costs?**

6
7 **A.** The company has indicated that it has taken a number of measures to ensure that the
8 Project stays on budget. These measures include:

- 9 • The construction risk is assigned to EDF; and
- 10 • There is a cap on transmission interconnection costs that the Company that allows
11 the Company to re-evaluate whether it wishes to take ownership of the project.

12 Because the Company has indicated that it has implemented these procedures for
13 controlling costs, it should assume the responsibility for implementing the measures.
14 Additionally, the customers have no control over these costs. Finally, if EDF is held to
15 the construction costs, the Company should also be held to the construction costs.

16
17 **Q. What are your recommendations with regards to reporting?**

18 **A.** In order for the Commission to be kept current on the construction progress, I
19 recommend that the Company file quarterly reports on the status of the construction of
20 the Project. In addition, in the ongoing monthly fuel cost adjustment reports, the
21 Company should include information about the amount of curtailments and negative
22 pricing, and any available explanation for those curtailments and prices.

23
24 **Q. Is it your expectation that the recommended reporting will create a large burden on
25 the Company?**

26 **A.** No. The Company in response to ND-PSC-02.27 acknowledged that "the Commission
27 may wish to include a periodic reporting obligation" regarding monitoring the
28 interconnection construction costs.

1
2 **Q. Should the Commission grant an ADP for the Astoria CT project?**

3
4 **A.** Yes, although I recommend that the ADP include the following qualifications:

- 5 • As the Company has only prepared a preliminary cost estimate, there should be cap
6 on the pre-approved construction costs of 10% above the \$165M estimate;
- 7 • Since there is not a definitive construction contract and schedule there should be a
8 limit on the in-service date; and
- 9 • The Company should provide quarterly construction progress reports until Astoria is
10 in service, indicating the development status of the project.

11 **Q. Why should the Commission put a cap on the construction cost as part of the ADP?**

12
13 **A.** The Company's cost estimate is based upon a preliminary estimate developed by Sargent
14 & Lundy. I agree with the Company that Sargent & Lundy is a construction firm with
15 significant experience in building generation projects. However, costs can change
16 significantly between preliminary estimates and firm bids due to a variety of reasons
17 including more detailed specifications for the project and changes in the cost of labor and
18 construction materials.

19 The Company indicates that they plan to use experienced construction firms and will
20 utilize appropriate risk mitigation measures. However, at this stage of the project they
21 have no specific plan for mitigating cost overruns.³⁹ Furthermore, while the Company
22 says it will reevaluate the project if there is a material increase in costs, they have not
23 defined what is "material" or committed to any maximum cost.⁴⁰

24
25
26
27
28 ³⁹ See OTP response to Case No: PU-17-140 NDPSC 2.9

⁴⁰ See OTP response to Case No: PU-17-140 NDPSC 2.33

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

3
4 A. No. The Company in response in its application acknowledged that "Consistent with
5 N.D.CC 49-05-16(3), Otter Tail will provide Project updates throughout the Project's
6 development as may be direct by the Commission".⁴¹

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

8
9 A. Yes.

10

11

12

13

14

15

16

17

18

19

20

21

22

23

24

25

26

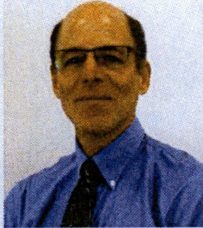
27

28

⁴¹ PU-17-140 Astoria ADP Application p 7
DIRECT TESTIMONY JAMES A HEIDELL - 52



Jim Heidell



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

| Primary expertise | Related experience | Qualifications |
|--|--|---|
| <ul style="list-style-type: none"> • 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 | <ul style="list-style-type: none"> • Strategic planning • Financial modelling of complex investments • Financial planning | <ul style="list-style-type: none"> • 30-years' experience with electric & gas utilities and electricity markets • MBA University of Washington • MSE Engineering Economics, Stanford University • BSE, Civil Engineering, Tufts University • CFA |

Primary expertise

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

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

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

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

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

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



Key client achievements

UTILITY REGULATORY SUPPORT

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

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

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

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

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

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

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

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

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

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

Developed an analysis 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.



MEXICO ENERGY MARKET REFORM

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

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

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

ELECTRIC MARKETS RISK MODELING

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

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

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

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

M&A and BANKRUPTCY ADVISOR

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

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

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



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

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

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

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

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

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

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

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

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

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

ELECTRIC GENERATION FINANCE SUPPORT:

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

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

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



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

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

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

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

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

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

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

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

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

Additional Expertise - Expert Testimony

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



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

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

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

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

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

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

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

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

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

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

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

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

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



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

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

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

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

JAH - 2

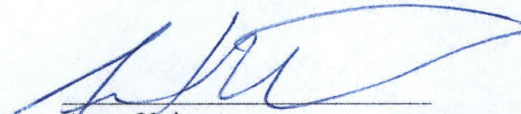
JAH - 3

Patrick J. Ward
Administrative Law Judge
Zuger Kirmis & Smith
P.O. Box 1695
Bismarck, ND 58502-1695

Cary Stephenson
Attorney at Law
P.O. Box 496
Fergus Falls, MN 56538-0496

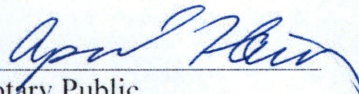
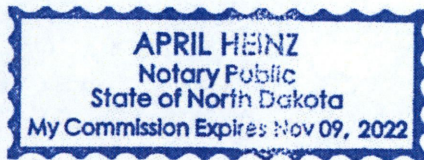
Illona Jeffcoat-Sacco
Attorney at Law
Public Service Commission
600 East Boulevard, Dept. 408
Bismarck, ND 58505-0480

and depositing the same, with postage prepaid, in the United States mail at Bismarck,
North Dakota.



Anna Heinen

Subscribed and sworn before me this 18th day of August, 2017.



Notary Public
Burleigh County, North Dakota