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Direct Testimony and Schedules

Dante Mugrace

**Before the North Dakota Public Service Commission
State of North Dakota**

In the Matter of the Application of
Northern States Power Company – North Dakota
a Division of Xcel Energy
For Authority to Establish Increased Rates for
Electric Service

Case No. PU-20-441

Overall Revenue Requirement
Rate Base Valuation
Operating Income

April 23, 2021

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1 **I. INTRODUCTION – STATEMENT OF QUALIFICATION**

2 **Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

3 **A.** My name is Dante Mugrace. My business address is 22 Brooks Avenue,
4 Gaithersburg, MD 20877.

5 **Q. WHAT IS YOUR PRESENT OCCUPATION?**

6 **A.** I am a Senior Consultant with the Economic and Management Consultant Firm of
7 PCMG and Associates, LLC. (PCMG). In my capacity as a Senior Consultant, I
8 am responsible for evaluating and examining rate and rate-related proceedings
9 before various governmental entities, preparing expert testimony and reviewing
10 and making recommendations concerning revenue requirement proposals, as well
11 as, offering opinions on economic policy and policy issues and methodologies
12 used to set a value on a utility's rate base and cost of service components of
13 revenue requirements.

14 **Q. PLEASE SUMMARIZE YOUR PROFESSIONAL EXPERIENCE?**

15 **A.** PCMG is an association of experts in the area of utility regulation and policy,
16 economics, accounting, and finance. PCMG's members have over 75 years of
17 collective experience providing assistance to counsel and expert testimony
18 regarding the regulation of electric, gas, water and wastewater utilities that operate
19 under local, state, and federal jurisdictions. PCMG brings to client engagements
20 a consultative and collaborative approach to the identification of issues and the
21 development of positions with strict adherence to client procedures and deadlines.
22 PCMG focuses on areas regarding revenue requirement, cost of service, rate
23 design, cost of capital and rate of return. We provide overall analyses on various
24 ratemaking concepts as well as a review of public utility accounting methods used
25 by various public utilities and State Public Service Commissions. We also evaluate
26 the reasonableness of costs and investments that are used to set rates, and
27 measure the value of rate base, whether these costs are prudent in nature, used
28 and useful and known and measurable in utility operations. Prior to my association
29 with PCMG, I was employed as a Senior Consultant with the consulting firm of
30 Snively-King Majoros and Associates (SKM) from 2013 to 2015 in the same

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1 capacity as PCMG. Prior to SKM, I was employed by the New Jersey Board of
2 Public Utilities (NJBPU or BPU or Board) from 1983 to my retirement in 2011.
3 During my tenure at the NJBPU, I held various Accounting, Auditing, Rate Analyst,
4 Supervisory and Management positions. My last position was Bureau Chief of
5 Rates in the Agency's Water Division (Bureau Chief of Rates). I held this position
6 for nearly 10 years. My CV is attached as Appendix A.

7 **Q. WHAT EXPERIENCE DO YOU HAVE IN THE AREA OF UTILITY RATE**
8 **SETTING PROCEEDINGS AND OTHER REGULATORY AND UTILITY**
9 **MATTERS?**

10 **A.** In my capacity as Bureau Chief of Rates, I was responsible for managing,
11 assigning, directing, and overseeing the rate process regarding the administrative,
12 financial, and managerial functions of the Rates Bureau. My primary duties were
13 to ensure that the utilities had sufficient revenues to cover their operating
14 expenses, while ensuring that those expenses were reasonable in nature, prudent,
15 and known and measurable in providing service and benefits to customers, and
16 were in accordance with Board policies, regulatory standards, and prior rate
17 Orders. I also was responsible to ensure that the utilities had the opportunity to
18 earn a reasonable return on their plant investments, including the ability to provide
19 safe, adequate, and proper service at reasonable rates. During my time at the
20 NJBPU, I was involved in hundreds of rate and rate-related proceedings that were
21 resolved either through settlement or through fully litigated proceedings. In my
22 capacity as a Senior Consultant, I was involved or am currently involved in rate
23 and rate-related proceedings before the Commissions in the Commonwealths of
24 Massachusetts and Pennsylvania, and the States of Hawaii, Maine, Maryland,
25 New Jersey, New York, North Dakota, and Ohio. I was involved in the Generic
26 Proceedings to Establish Parameters for the Next Generation Performance Based
27 Rate Plans before the Alberta Utilities Commission. I have been or am currently
28 involved in matters before the Federal Energy Regulatory Commission ("FERC")
29 regarding transmission formula rate plans. More recently I was involved in the
30 Generic Proceeding instituted by the NJ Board of Public Utilities (NJBPU)
31 regarding the Tax Cuts and Jobs Act of 2017 (BPU Docket No. AX1801001)

1 regarding the setting of the federal tax adjustments and the adjustment of rates
2 and the impact on the flowback of excess accumulated deferred income taxes. I
3 am currently involved in several proceedings with the NJBPU with respect to the
4 establishment of energy efficiency and peak demand reduction programs in
5 accordance with the NJ Clean Energy Act of 2018 (BPU Docket Nos.
6 QO19010040, QO19060748 and QO17091004).

7 **Q. WHAT IS YOUR EDUCATIONAL BACKGROUND?**

8 **A.** I hold a Master of Business Administration ("MBA") degree with a concentration in
9 Strategic Management from Pace University – Lubin School of Business in New
10 York City, New York. I hold a Master of Public Administration ("MPA") degree from
11 Kean University in Union, New Jersey. I hold a Bachelor of Science ("BS") degree
12 in Accounting from Saint Peter's University in Jersey City, New Jersey.

13 **Q. ON WHOSE BEHALF ARE YOU TESTIFYING?**

14 **A.** I am testifying on behalf of the Advocacy Staff of the North Dakota Public Service
15 Commission (NDPSC).

16 **II. PURPOSED OF TESTIMONY**

17 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

18 **A.** The purpose of my testimony is to evaluate and make a revenue requirement
19 recommendation regarding Northern States Power Company's (NSP or Company)
20 electric base rate case proceeding filed with the North Dakota Public Service
21 Commission (NDPSC or Commission), that was filed on November 6, 2020 in
22 Case No. PU-20-441. My overall revenue requirement recommendations are
23 based upon the Company's proposed test year period ending December 31, 2021.
24 The Company has proposed an annual revenue requirement increase of
25 \$22,227,649 or 10.80% over current rate revenues. Incorporated into my
26 testimony, I have presented findings with respect to the Company's test year rate
27 base, revenues, operating expenses and net income at present rate revenues. I
28 have incorporated and am relying on the recommendations of Dr. Marlon Griffing
29 for cost of capital and return on equity, James Garren on Depreciation and Dr. Karl

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1 Pavlovic for cost of service and rate design that may affect my revenue
2 requirement.

3 **Q. HAVE YOU REVIEWED AND EXAMINED THE COMPANY'S TESTIMONY AND**
4 **ACCOMPANYING EXHIBITS IN THIS PROCEEDING?**

5 **A.** Yes. I have reviewed NSP's testimony, statements and exhibits, and have also
6 reviewed and relied on the responses to data requests propounded by Advocacy
7 Staff and PCMG.

8 **Q. HAVE YOU PREPARED SCHEDULES TO ACCOMPANY YOUR TESTIMONY?**

9 **A.** Yes. I have prepared Schedules DM-1 through DM-24.

10 **Q. PLEASE SUMMARIZE THE RATE RELIEF PROPOSED BY NSP.**

11 **A.** As previously indicated above, the Company filed an application for an increase in
12 electric service on November 6, 2020, requesting an increase in base distribution
13 rates in the amount of \$22,227,649 or 10.80% above current rates. The revenue
14 requirement is predicated upon a future test year ending December 31, 2021,
15 (Exhibit BCH-1 page 18) which include an overall rate of return of 7.35% and a
16 common equity component of 10.80%. The Company has computed an average
17 rate base balance of \$676,754,684 based upon average balances of plant
18 investments. The Company is proposing to include certain "roll-in" costs into rate
19 base related to certain renewable energy and transmission projects that are
20 currently being recovered through the Company's Renewable Energy Rider (RER)
21 and Transmission Cost Recovery (TCR) Rider. As described by the Company,
22 these roll-ins do not affect the overall impact of the revenue requirement
23 deficiency. The Company's last base rate case was approved in 2014 by the
24 Commission in Case No. PU-12-813.

25 **Q. HOW DID THE COMPANY COMPUTE ITS PROPOSED REVENUE**
26 **REQUIREMENT INCREASE OF \$22,227,649.**

27 **A.** The Company has computed its proposed revenue requirement increase by
28 computing the average rate base (beginning and ending test year balances) and
29 the adding and subtracting average balances related to Cash Working Capital

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1 (CWC) materials and supplies, fuel inventory, prepayments and various non-plant
2 assets and liabilities. The Company multiplied its proposed average rate base
3 balance of \$676,754,684 by the proposed rate of return of 7.35% to arrive at a
4 proposed Operating Income requirement of \$49,741,469. The Company then
5 subtracted its Operating Income at present rates of \$32,938,456 to arrive at an
6 income deficiency of \$16,803,013.¹ The Company then multiplied this amount by
7 its revenue conversion factor of 1.32284 to arrive at its revenue requirement
8 increase proposal of \$22,227,649.

9 **Q. HAVE YOU ACCEPTED THE COMPANY'S PROPOSED TEST YEAR ENDING**
10 **DECEMBER 31, 2021?**

11 **A.** Yes.

12 **Q. HAS THE COMPANY UPDATED ITS PROPOSED REVENUE REQUIREMENT**
13 **INCREASE SUBSEQUENT TO THE NOVEMBER 6, 2020 FILING DATE?**

14 **A.** Yes. On March 3, 2021, the Company updated its revenue requirement noting an
15 error in the Company's calculation related to an expense item for gas demand.
16 The Company discovered a deviation that corrected costs associated with the
17 reservation of firm transportation and storage capacity for the Company's natural
18 gas generating units. The resulting adjustment reduced the Company's overall
19 revenue requirement from \$22,227,649 to \$19,160,672 or a reduction of
20 \$3,066,977. (Table I to the March 3, 2021 letter). On March 26, 2021, the
21 Company filed updated direct testimonies, updated documents, exhibits and
22 schedules as well as updated interim tariff sheets (dated March 12, 2021) in
23 support of its updated revenue requirement increase of \$19,160,672. The
24 Commission approved the interim rate correction on March 19, 2021.

25 **Q. HAS THE COMPANY CONSIDERED THE IMPACT OF THE COVID-19**
26 **PANDEMIC ON ITS PROPOSED RATE REQUEST?**

27 **A.** Company witness Mr. Chamberlain in his revised direct testimony stated that the
28 Company has recognized that the rate request will impact customers during these
29 difficult times and acknowledges that the rate request comes also as COVID-19

¹ Company Exhibit BCH-1 Schedule 7 page 1.

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1 has further exacerbated the Company's need for rate relief. (Exhibit GPC-1
2 Revised page 8). Mr. Chamberlain stated that the impact of COVID-19 has
3 contributed almost \$5 million of the Company's deficiency, and accounts for more
4 than 10 percent of the overall deficiency from 2019-2021. (Exhibit GPC-1 Revised
5 page 8).

6 **Q. WHAT ACTIONS HAS THE COMPANY TAKEN WITH RESPECT TO THE**
7 **COVID-19 PANDEMIC?**

8 **A.** Mr. Chamberlain stated that the Company has suspended account disconnections
9 through the summer and waived late fees for many of its customers. The Company
10 will be reconsidering what additional measures it can take to help support its
11 customers. (Exhibit GPC-1 Revised page 9).

12 **Q. PLEASE SUMMARIZE YOUR FINDING AND RECOMMENDATIONS.**

13 **A.** Based upon the use of the Company's test year period ending December 31, 2021,
14 I have the following recommendations:

- 15 1. My recommended rate base balance is \$658,448,863, which is \$18,467,137
16 lower than the Company's proposed rate base balance of \$676,916,776.
- 17 2. My rate of return is based upon the recommendation of Dr. Marlon Griffing
18 which recommends an overall return of 6.8175%, which includes a common
19 equity component of 9.50%.
- 20 3. My recommended operating revenues at present rates is \$245,638,651 which
21 is \$338,094 lower than the Company's operating revenues at present rates of
22 \$245,976,745.
- 23 4. My overall revenue requirement increase based upon an overall rate of return
24 of 6.818% is \$3,590,775 or 1.740%; this is \$15,606,182 lower than the
25 Company's overall revenue requirement increase of \$19,197,034 or 9.30%.

26 **Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?**

27 **A.** The remainder of my testimony is organized by documenting and explaining
28 adjustments to various rate base components and net operating income
29 components to arrive at my recommended revenue requirement decrease.

1 Q. ARE YOU ACCEPTING ANY OF THE COMPANY'S PROPOSED RATE BASE
2 BALANCE AND OPERATING INCOME ADJUSTMENTS?

3 A. Yes. I am accepting certain of the Company's Rate Base balances and certain of
4 the Company's Operating Income adjustments. These adjustments are not
5 identified in my testimony but are identified in my revenue requirement schedules.
6 My testimony reflects the areas of disagreement from that of the Company and the
7 affect these adjustments have on rates.

8

9

III. Cost of Capital

10 Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS COST OF
11 CAPITAL?

12 A. The Company has proposed an overall Cost of Capital of 7.35%. The breakdown
13 of this return is based upon a long-term debt rate of 4.2189%, a short-term debt
14 rate of 1.000% and a common equity component of 10.20%. (WP C1- Cost of
15 Capital Schedule).

16 Q. WHAT IS YOUR RECOMMENDED COST OF CAPITAL?

17 A. As per Advocacy Staff witness Dr. Griffing's recommendation, I am incorporating
18 an overall cost of capital of 6.8175% which includes a common equity component
19 of 9.50%. This is shown on Schedule DM-2, and on Dr. Griffing's Exhibit MFG-
20 20, Schedule 3.

21

22

REVENUE REQUIREMENT ISSUES

23

IV. Rate Base Issues

24

A. Electric Plant in Service

25 Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS ELECTRIC
26 PLANT IN SERVICE BALANCE?

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1 **A.** As shown on Exhibit BCH-1 Schedule 3A the Company proposed an average plant
2 in service balance of \$1,471,793,933, as of December 31, 2021. The Company
3 has developed this balance starting with total Company investments proposed in
4 the 2021 test year period and allocating investments to the North Dakota
5 jurisdiction (Exhibit BCH-1 page 24). The Company calculated the investment
6 related to the North Dakota jurisdiction by the use of a simple average of projected
7 net plant at the beginning and end of the test year consistent with the method
8 employed in the Company's most recent North Dakota electric rate case (BCH-1
9 page 24).

10 **Q.** **HOW DID THE COMPANY DEVELOP THE PLANT BALANCES FOR THE END**
11 **OF THE TEST YEAR 2021?**

12 **A.** The Company stated that the 2021 ending plant balances were determined by
13 applying the data contained in the 2021 capital budget adjusted for plant additions,
14 retirement, depreciation, salvage and removal costs projected to occur during the
15 test year. (Exhibit BCH-1 page 25). The Company developed its projected plant
16 additions beginning in 2013 and adding plant investments through 2019. (Exhibit
17 MPM-1 page 4). The Company stated that it made a wide variety of investments
18 across total Company system to provide reliable, safe, cost-effective service to its
19 customers. Company witness Mr. Moeller included projects related to investment
20 in wind farms, regional expansion transmission projects, nuclear generating fleet,
21 a new natural gas combustion turbine, and updating the Company's information
22 technology and business systems. (Exhibit MPM-1 page 4).

23 **Q.** **HOW DOES THE COMPANY ALLOCATE ITS ELECTRIC PLANT IN SERVICE**
24 **BALANCE FROM THAT OF THE PARENT COMPANY – XCEL ENERGY AND**
25 **NORTHERN STATES POWER COMPANY – MINNESOTA (NSPM)?**

26 **A.** The Company allocates its Electric Plant in Service (EPIS) balance by the use of
27 jurisdiction allocations from NSPM to each of the regulated subsidiaries in the
28 North Dakota and South Dakota operations (NDPSC 5-026 Attachment A). The
29 jurisdiction cost of service study allocates rate base, capital structure, cost of
30 capital, income taxes and cash working capital from NSPM to the North Dakota
31 jurisdiction (Exhibit BCH-1 page 20). The Company relied on historical actual net

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1 investments on the Company's books and records as of June 30, 2020, and
2 budgeted projections for July through December 2020. The ending net plant
3 balances as of December 31, 2021, were determined by applying the data
4 contained in the 2021 capital budget to the ending balance as of December 2020,
5 and simple average was used to compute the proposed EPIS at the end of the
6 future test year period. The Company is allocated investments from NSPM to it
7 through allocation factors for demand, energy and customers. Production related
8 investments are allocated by a demand/energy factor; Transmission related
9 investments are allocated by a demand factor; General related investments are
10 allocated by a demand/customer/direct assignment factor and; Common related
11 investments are allocated by a demand/customer/direct assignment factor
12 (NDPSC 5-026 Attachment A and Exhibit BCH-1 Revised Schedule 13). The
13 allocation factors for the 2020 current and 2021 test year periods are as follows:

14	Demand	6.1731%
15	Energy	6.7739%
16	Customers	6.2590%
17		

18 **Q. DO YOU HAVE ANY CHANGES OR ADJUSTMENTS TO THE COMPANY'S**
19 **ALLOCATIONS FACTORS USED IN THE DEVELOPMENT OF THE**
20 **COMPANY'S REVENUE REQUIREMENT?**

21 **A.** No. I am accepting the Company's proposed allocation factors that were used in
22 the development of the Company's revenue requirement proposal.

23 **Q. DO YOU HAVE ANY ADJUSTMENTS WITH RESPECT TO THE COMPANY'S**
24 **EPIS BALANCE OF \$1,471,794,000 (ROUNDED)?**

25 **A.** Yes, I have (three) adjustments to the Company's EPIS balance. My first
26 adjustment is related to the Company's proposed Prairie Island EPU Uprate
27 Recovery. I am removing approximately \$4.109 million from the Company's EPIS
28 balance. My second adjustment is related to the Company's proposed Jeffers
29 Wind and Community Wind North Facilities. I am removing approximately [trade
30 secret data begins] [REDACTED]
31 [REDACTED] [trade secret data ends] (NDSPC-076). My third
32 adjustment is related to the Company's Advanced Grid Intelligence and Security

1 (AGIS) Initiative. I am removing approximately \$4.43 million that has been
2 assigned to the North Dakota Electric jurisdiction (NDPSC-5-072 and Table 5 of
3 Exhibit KAB-1 page 42).

4 Prairie Island EPU Uprate Recovery

5 **Q. PLEASE PROVIDE THE BACKGROUND AND DESCRIBE THE COMPANY'S**
6 **REASONING FOR INCLUDING THE PRAIRIE ISLAND EPU UPRATE IN ITS**
7 **EPIS BALANCE?**

8 **A.** Company witness Shaw proposes to include costs associated with a 164 MW
9 uprate of the Prairie Island (PI) nuclear power plant that was expected to cost about
10 \$322 million and be implemented during the 2015 and 2016 refueling outages
11 (Exhibit CJS-1 page 64). Mr. Shaw stated that the PI EPU project was prudent at
12 the time the Company decided to move forward with the project during the 2015-
13 2016 time period. Mr. Shaw stated that the PI EPU project was seen as a cost-
14 effective hedge against both higher natural gas prices and the potential for federal
15 carbon legislation. (Exhibit CJS-1 page 64). The Company sought regulatory
16 approval from the Minnesota Public Utility Commission (MPUC) to undertake the
17 uprate (Exhibit CJS-1 page 65).

18 The Company sought an Advanced Determination of Prudency (ADP) from the
19 NDPSC in April 2010. (Exhibit CJS-1 page 65). On October 23, 2012, the
20 Company asked the NDPSC to postpone consideration of the ADP due to a
21 change in circumstance. (Exhibit CJS-1 page 65). On May 16, 2008, the Company
22 submitted a Certificate of Need application with the MPUC for the Prairie Island
23 EPU, and on December 18, 2009, the MPUC granted a Certificate of Need for the
24 PI EPU. (Exhibit CJS-1 page 66). The Company sought uprate licenses from
25 Nuclear Regulatory Commission (NRC) (Exhibit CJS-1 page 67). While the NRC
26 license amendment process was ongoing, the Company reassessed moving
27 forward with the project (Exhibit CJS-1 page 67).

28 The Company encountered several changes to the EPU Project and industry
29 conditions over the course of 2011 and 2012 that led to the Company to reassess
30 the prudence analysis for the Project. (Exhibit CJS-1 page 68). Project

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1 implementation was delayed from 2014-2015 to 2016-2017. The Company did not
2 receive approval until June 2011 and the NRC rules did not allow submission of a
3 License Amendment Request (LAR) while a license renewal was pending. (Exhibit
4 CJS-1 page 68-69). The NRC Staff required significantly more design detail before
5 granting acceptance than had previously been the case. This would have caused
6 the Company to incur significant time and investment before receiving any
7 feedback from the NRC. (Exhibit CJS-1 page 69). The reason being was due to
8 the Fukushima Daiichi incident (March 2011) in that the NRC was in the process
9 of comprehensively reviewing the impact of external events on the safe operations
10 of nuclear power plants to determine if additional plant modifications or safety
11 regulations were necessary (Exhibit CJS-1 page 69).

12 In addition natural gas prices fell, shale gas had been ramping up and the surge in
13 production pushed gas prices down; the effect of lower gas prices mitigated the
14 hedge value of the PI EPU Project. (Exhibit CJS-1 page 70).

15 **Q. WHAT DID THE COMPANY DO IN LIGHT OF THE CIRCUMSTANCES**
16 **DESCRIBED ABOVE?**

17 **A.** In light of the changes described above and the lowering of the benefits as shown
18 on Table 8 of Exhibit CJS-1 page 72, as well as the uncertainty around the NRC
19 processes at the time, the Company held out the possibility of additional project
20 delay and the concomitant increase in costs, the PI EPU Project benefits would
21 have been further reduced by lower natural gas prices or low load growth, and the
22 project risk outweighed the qualitative benefits. (Exhibit CJS-1 pages 74-75).

23 **Q. WHY DID THE COMPANY CANCEL THE PRAIRIE ISLAND EPU PROJECT?**

24 **A.** Company witness Shaw stated that after the Company's March 2012 analysis
25 raised questions about the economic benefit and ultimate prudence of the PI EPU
26 Project, the Company ramped down and suspended the Project, which had yet to
27 start construction. (Exhibit CJS-1 page 75). The Company informed the MPUC
28 that based upon the updated analysis, Xcel Energy concluded that the outstanding
29 risks of delay and increased costs outweighed the small potential benefit and made
30 further investments imprudent. (Exhibit CJS-1 page 76). The MPUC issued an

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1 Order concurring with the Company's conclusion and terminated the Certificate of
2 Need for the PI EPU Project (Exhibit CJS-1 page 76).

3 **Q. WHAT IS THE COMPANY REQUESTING THE NORTH DAKOTA PUBLIC**
4 **SERVICE COMMISSION (NDPSC) TO APPROVE?**

5 **A.** The Company is requesting that the NDPSC approve the recovery of the PI EPU
6 Project in rates, even though the Project was cancelled, stating the Company's
7 decision was prudent based upon the circumstances at the time the Company
8 began to move forward with the Project. (Exhibit CJS-1 page 77).

9 **Q. WHAT IS YOUR RECOMMENDATION?**

10 **A.** I am recommending removal of the PI EPU Project from the Company's EPIS
11 balance of \$4.109 million, and the related revenue requirement recovery
12 associated with the Project. The Company is requesting recovery of investments
13 that are not used or useful in the provision of utility service. The Company is relying
14 on its decision when it began to undertake the PI EPU Project based upon the
15 circumstances at the time surrounding the decision to seek approval of this Project.
16 The Company is also relying upon the decision by the MPUC, which concurred
17 with the Company, to terminate and abandon the Project. The decision by the
18 Company to undertake and subsequently abandon and terminate the PI EPU
19 Project was a business decision with risks associated with the Project. The risks
20 should stay with the Company and the end result should not be passed onto the
21 North Dakota customers.

22 The Company is now asking North Dakota ratepayers to pay for costs that will not
23 benefit them, not provide utility service, and not be used and useful. The Company
24 is requesting that the North Dakota customers assume the costs of and bear the
25 risk of rate recovery. If the Commission were to approve the recovery of the costs
26 of all abandoned projects and have the North Dakota customers assume these
27 risks, the Company will have no responsibility to curtail and restrict what dollars
28 the Company will invest in, because it will be assumed that whatever the outcome,
29 the Company will be made whole.

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1 Further, the Company assumes that since the MPUC concurred with the Company
2 about terminating the Projects, it is assumed that the North Dakota Commission
3 will follow suit. Basic ratemaking principles require that costs and investments be
4 known and measurable, prudent in nature and used and useful. The PI EPU
5 Project is none of these; therefore, these costs should not be recovered by
6 customers in rates for service. My adjustment is shown on Schedule DM-5.

7 Jeffers Wind and Community Wind North Facilities

8 **Q. PLEASE PROVIDE THE BACKGROUND AND DESCRIBE THE COMPANY'S**
9 **REASONING FOR INCLUDING THE JEFFERS WIND PROJECT AND THE**
10 **COMMUNITY WIND NORTH PROJECT (PROJECTS) IN ITS EPIS BALANCE?**

11 **A.** According to Company witness Mr. Shaw, the Company has included two
12 repowered wind projects in EPIS. The first project known as the Jeffers Wind
13 Project, which is a 44 MW wind project located in Cottonwood County, Minnesota.
14 The Company entered into a Purchased Power Agreement (PPA) with Jeffers
15 Wind on July 31, 2006 with a term of 20-years. The second project known as the
16 Community Wind North Project consists of two 13.2 MW wind projects located in
17 Lincoln County, Minnesota. The Company entered into two PPA's with Community
18 Wind North on May 28, 2010 with a term of 20-years. (Exhibit CJS-1 page 93).
19 These two projects were given statutory priority in Minnesota at the time prior to
20 the Community Based Energy Development (C-BED) statute was repealed (2016)
21 by the Minnesota Legislature. These C-BED projects were more favorable as to
22 pricing compared to non-C-BED projects. (Exhibit CJS – 1 page 94).

23 **Q. WHEN DID THE COMPANY ACQUIRE THE PROJECTS?**

24 **A.** The Company acquired the Projects in December 2019. The Company found that
25 these acquisitions were prudent and consistent with the public interest and were
26 approved by the MPUC. The transaction is expected to close in November. (Exhibit
27 CJS-1 page 94-95).

28 **Q. DID THE COMPANY REQUEST AN ADVANCE DETERMINATION OF**
29 **PRUDENCE (ADP) IN NORTH DAKOTA?**

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1 **A.** No. Mr. Shaw stated that pursuant to the Settlement Agreement (PU-07-776) the
2 Company is required to seek an ADP for any resource addition that is 50 MW or
3 greater. Both Jeffers Wind and Community Wind North are under 50 MW and were
4 not acquired as part of the portfolio like the 187 MW Solar Portfolio I. (Exhibit CJS-
5 1 page 95). The Company stated that the resource additions related to these
6 Projects were prudent at the time the decision was made to add the resources in
7 order for the costs to be recovered in rates. (Exhibit CJS-1 page 95). The PPAs
8 will be cancelled when the Company acquires the Projects. (Exhibit CJS-1 page
9 95). The Company is not recovering costs and volumes of 15 specified C-BED
10 wind projects including Community Wind North and Jeffers Wind, in its calculation
11 of the Fuel Cost Rider (FCR) but is recovering the system average cost of fuel for
12 the production of these Projects. (Exhibit CJS-1 page 95-96). The Company is
13 requesting that the North Dakota Commission find that the decisions to acquire
14 these Projects to be prudent and allow recovery of the costs and energy in base
15 rates. (Exhibit CJS-1 page 96).

16 **Q.** **WHAT IS THE COMPANY'S ARGUMENT REGARDING THE PRUDENCY OF**
17 **THESE ACQUISITIONS?**

18 **A.** The Company has stated that at the time the decisions were made to acquire the
19 Projects it was prudent. However, the Company did not perform an updated
20 analysis of the Jeffers Wind Acquisition as it would be inappropriate because the
21 prudence of the decision is measured by the information at hand when the
22 Company acquired the facility. (Exhibit CJS-1 page 98). With respect to the
23 Community Wind North Acquisition the Company performed an analysis when the
24 Company was considering acquiring the facilities and has not performed any
25 updated analysis because the prudence of the decision is measured by the
26 information at hand at the time of acquisition. These analyses are consistent with
27 North Dakota evaluation standards. (Exhibit CJS-1 page 106).

28 **Q.** **WHAT IS YOUR ANALYSES REGARDING THE COMPANY'S ACQUISITIONS**
29 **OF BOTH THE JEFFERS WIND AND COMMUNITY WIND NORTH PROJECTS?**

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1 **A.** These two Projects are located in Minnesota. The PPAs were entered into in July
2 2006 (Jeffers Wind) and May 2010 (Community Wind North). These Projects were
3 approved to provide energy in Minnesota under the MPUC. The prior owners of
4 both Jeffers Wind and Community Wind North indicated to the Company that they
5 were undertaking a substantial project to refurbish both facilities, in order to ensure
6 successful operations for the duration of the PPAs and beyond and to re-qualify
7 for Production Tax Credits (PTCs). (Exhibit CJS-1 page 94). The Company
8 subsequently purchased these projects, the refurbishing was completed in 2020,
9 and the MPUC found these acquisitions to be prudent and consistent with the
10 public interest (Exhibit CJS-1 page 94).

11 The Company is relying on the Minnesota Public Utility Commission as far as
12 prudency and the recovery of costs in rates and is asking the North Dakota
13 Commission to adopt the MPUC's approach without adequate consideration on
14 the usefulness of these Projects. The Company has stated that it did not perform
15 updated analyses on these Projects because the Company stated that it "would be
16 inappropriate because the prudence of the decision is measured by the information
17 at hand when the Company made the decision to acquire the facility." Given the
18 time between entering into these PPA's (2006 for Jeffers Wind and 2010 for
19 Community Wind North), and the fact that Company acquired these Projects in
20 2019, the resource portfolio may have changed, and it would be prudent to revisit
21 the prudency issue. Also, the Company's reliance on the MPUC decision should
22 have no bearing on what the North Dakota Commission will or might do. The
23 business risk of these acquisitions should remain with the Company since the
24 Company has made the sole determination of acquiring these Projects, not
25 knowing or addressing what the outcome the ND Commission directives mandates
26 might be to allow these investments in ratesMy adjustment is shown on Schedule
27 DM-5.

28
29
30

1 AGIS

2 **Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED INCLUSION OF COSTS**
3 **RELATED TO ITS AGIS INITIATIVE.**

4 **A.** As shown in response to NDPSC 5-72 the Company is proposing to recover about
5 \$4.43 million in the test year related to the AGIS Program. These costs relate to
6 several foundational elements: (1) Advanced Distribution Management System
7 (ADMS) of \$3.07 million; (2) Geospatial Information System (GIS) of \$110,000; (3)
8 Field Area Network (FAN) of \$530,000 and: (4) Automated Metering Infrastructure
9 (AMI) of \$720,000. Each of these components have different deployment
10 timeframes and are in a different stage of development. (NDPSC-5-69).

11 Company witness Bloch has stated that the AGIS Initiative is a multi-year project
12 to create benefits for customers by transforming the Company's distribution system
13 into an intelligent and highly automated system. (Exhibit KAB-1 page 35). The
14 Company stated that the technical capabilities of the current grid are limited
15 compared to more advanced grid technologies, and the overall system is
16 somewhat opaque, in that there is little insight into performance and operation
17 beyond the substation level. (Exhibit KAB-1 page 35). AGIS seeks to take
18 advantage of developed and enhanced technologies to increase grid reliability,
19 transparency, efficiency and access by enhancing grid visibility and creating the
20 infrastructure to support and actualize advanced grid technologies. (Exhibit KAB-
21 1 page 35). The AGIS is being implemented through a building block approach.
22 (Exhibit KAB-1 page 36).

23 **Q. WHAT HAS THE COMPANY INDICATED WITH RESPECT TO WHEN IT PLANS**
24 **TO IMPLEMENT THE AGIS INITIATIVE?**

25 **A.** According to the response to NDPSC 5-69, the Company began implementing the
26 AGIS in 2017, and the ADMS portion will be fully placed in service during the 2021
27 test year and will be used to enhance the operation of the distribution grid for North
28 Dakota customers. The Company has indicated that the GIS portion has gone live
29 in April 2021. The AMI will be deployed in 2022 and end in 2023. The FAN will be
30 deployed six-months prior to the AMI meter installation. The Company has

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1 deployed a small number of AMI meters and FAN infrastructure to support a time-
2 of-use rate pilot in Minnesota, which involves 17,500 AMI meters and two FAN
3 backhaul communication devices (NDPSC 5-69). The complete roll-out of AMI
4 meters will be in 2024 (Exhibit KAB-1 page 40). The Company has stated that the
5 total investment in each jurisdiction will vary based on regulatory approvals for
6 different components, and given the need to replace AMI meters, the Company
7 will be implementing ADMS, FAN and AMI in all of its jurisdiction by 2025. (Exhibit
8 KAB-1 page 41).

9 **Q. WHAT IS THE COMPANY'S REASON FOR PLACING AGIS IN SERVICE?**

10 **A.** According to Ms. Bloch, the current meters need to be replaced, and the
11 Company's current automated meter reading (AMR) technology is nearing end of
12 life. The meter reading services vendor Landis+Gyr (Cellnet) has informed the
13 Company that it will no longer manufacture replacement parts for the system after
14 2022. The contract with Cellnet for meter reading services expires at the end of
15 2025. (Exhibit KAB-1 page 36). The Company has implemented some of these
16 technologies in pilot areas and based upon the results of those pilots, the Company
17 believes it makes sense now to pair replacement of the existing AMR meters with
18 long-term investment in modernizing the distribution system. (Exhibit KAB-1 page
19 37).

20 **Q. WHAT IS YOUR RECOMMENDATION WITH RESPECT TO THE COMPANY'S**
21 **AGIS INITIATIVE?**

22 **A.** I am recommending that the costs of \$4.43 million included in the Company's EPIS
23 be removed and not recovered from the North Dakota customers at this time. It
24 appears that these costs or the various components related to the North Dakota
25 jurisdiction will not be fully in-service, and used and useful by the end of the test
26 year. In response to NDPSC 5-69, the Company stated that the AMI infrastructure
27 is expected to be deployed in North Dakota to begin in 2022 and end in 2023,
28 which is beyond the test year period, and beyond the time frame when the North
29 Dakota Commission is expected to rule and implement new rates in this
30 proceeding. I am of the opinion that each of the Company's components (ADMS,

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1 GIS, FAN and AMI) all need to be implemented concurrently or simultaneously, in
2 order to provide benefits to the North Dakota jurisdictional customers. The
3 Company's "building-block" approach as explained by Ms. Bloch (Exhibit KAB-1
4 page 50), does not appear to be prudent or known and measurable.

5 Until such time as the Company has fully rolled-out the infrastructure assigned to
6 the North Dakota jurisdictional customers, these costs should not be recovered
7 from the North Dakota customers. The Company's argument that these
8 components are currently being deployed in the NSPM territory and used in a pilot
9 program in Minnesota would allow costs and expenditures to be recovered by the
10 North Dakota jurisdictional customers without being used and providing service to
11 customers. As stated in Exhibit KAB-1 page 60-61, certain AGIS components will
12 begin to be rolled-out in 2021 and certain AGIS components are expected to be
13 completed and implemented in 2024, with final completion in 2025.

14 **Q. WHAT HAS THE COMPANY STATED WITH RESPECT TO THE CAPITAL**
15 **ADDITIONS FOR AMI AND FAN BEFORE THE AGIS INITIATIVES ARE**
16 **ROLLED-OUT IN NORTH DAKOTA?**

17 **A.** Ms. Bloch stated that the AGIS initiative and the wholesale replacements of
18 customer meters and the large and distributed communication system are both
19 large and complex projects. In advance of the large-scale physical installation
20 efforts, the Company must undertake a variety of tasks including project
21 management, planning activities and testing. (Exhibit KAB-1 page 61). The
22 Company is requesting that the Commission allow recovery of the foundational
23 components of AGIS which include the full ADMS implementation and the first set
24 of investments in the FAN. (Exhibit KAB-1 page 64).

25 **Q. WHAT IS YOUR ARGUMENT FOR NOT ALLOWING THESE COSTS IN RATE**
26 **BASE OR IN THE COMPANY'S EPIS BALANCE?**

27 **A.** These costs will not provide benefit to the North Dakota jurisdictional customers
28 until these costs and investments are fully placed in service, become used and
29 useful and are prudent in nature. The Company indicated that the cost increases
30 through 2025 include contingencies to ensure that the funds for the resources and

1 maintenance that will be needed for the AGIS are covered. (Exhibit KAB-1 page
2 64). Given that these costs will change over time as the Company's rolls out the
3 components of AGIS, these costs are not known and measurable and should not
4 be included in recovery at this time. The Company's proposal to include
5 foundational component costs in the test year are premature. It appears that the
6 Company is proposing to recover costs that have been incurred in the NSPM
7 Minnesota jurisdiction and allocating the jurisdictional portion of these costs to
8 North Dakota ratepayers. The Company should request from the Commission that
9 these investments be booked in a regulatory asset account, and request recovery
10 at a time when these costs become known and measurable, provide service to the
11 North Dakota jurisdictional customers and are used and useful in the provision of
12 utility service.

13 **B. Accumulated Depreciation**

14 **Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ACCUMULATED**
15 **DEPRECIATION?**

16 **A.** In the same manner as the Company developed its EPIS balance, the Company
17 performed the same analysis with respect to its Accumulated Depreciation or
18 Depreciation Reserve amount, by taking the simple average of balances at the
19 beginning and end of test year. The Company proposed an average depreciation
20 reserve balance of \$677.840 million as shown on Company Exhibit BCH-1
21 Schedule 3A.

22 **Q. DO YOU HAVE ANY ADJUSTMENTS WITH THE WAY THE COMPANY**
23 **DEVELOPED ITS ACCUMULATED DEPRECIATION BALANCE?**

24 **A.** No. I am accepting the Company's methodology as to the development of the
25 Company's Accumulated Depreciation.

26 **Q. WHAT SPECIFIC ADJUSTMENTS DO YOU HAVE REGARDING YOUR**
27 **ADJUSTMENTS TO THE COMPANY'S EPIS BALANCE?**

28 **A.** Given that I made adjustments to the Company's Depreciation Study for Sherco
29 Units 1 and 2, the Prairie Island EPU Recovery, the Jeffers Wind and Community
30 North Wind facilities, and the AGIS initiative, I am making the associated

1 adjustments related to the accumulated depreciation balance. For the
2 Depreciation Study for Sherco Units 1 and 2, I am making a (\$1,741,277)
3 adjustment.(WP-A11/A12). For the Prairie Island EPU Recovery I am making a
4 (\$154,000) adjustment (WP-A-19). For the Jeffers Wind and Community Wind
5 North I am making a [trade secret data begins] [REDACTED] [trade secret data
6 ends] adjustment as shown on confidential NDPSC 5-076 Attachment B.

7 **Q. WHAT IS YOUR FINAL ADJUSTMENT WITH RESPECT TO THE COMPANY'S**
8 **AGIS INITIATIVE?**

9 **A.** Since I removed the Company's AGIS Initiative costs under the Company's EPIS
10 balance, I am removing the associated Accumulated Depreciation. The Company
11 has indicated that the AGIS project is being depreciated at 10% (NDPSC 12-16).
12 Therefore, I am adjusting the Accumulated Depreciation by (\$4.43 million times
13 10% or \$443,000). My adjustments are shown on Schedule DM-6.

14 **C. Accumulated Deferred Income Taxes (ADIT)**

15 **Q. WHAT HAS THE COMPANY PROPOSED REGARDING ITS ACCUMULATED**
16 **DEFERRED INCOME TAXES?**

17 **A.** The Company has proposed an ADIT balance of \$147,085,925 as shown on
18 Exhibit BCH-1 Revised Schedule 15. The Company used an average projected
19 ADIT balance to recognize funds for corporate use between the time they are
20 collected in rates and ultimately remitted to the respective taxing authorities.
21 (Exhibit BCH-1 page 27). Incorporated into the ADIT balance is the amortization
22 of the excess plant-related ADIT with respect to the Tax Cuts and Jobs Act of 2017
23 (TCJA). The Company is using the Average Rate Assumption Method (ARAM) to
24 amortize the excess non-plant related ADIT over a period ranging from five to
25 fifteen years. The Company is amortizing the excess plant related ADIT using
26 ARAM. (Exhibit BCH-1 page 27-28).

27 **Q. DO YOU HAVE ANY ADJUSTMENTS REGARDING THE COMPANY'S**
28 **METHODOLOGY ON THE DEVELOPMENT OF ITS ADIT?**

29 **A.** No. I am accepting the Company's methodology as to the development of the
30 Company's ADIT.

1 Q. WHAT SPECIFIC ADJUSTMENTS DO YOU HAVE REGARDING YOUR
2 ADJUSTMENTS TO THE COMPANY'S EPIS BALANCE?

3 A. Given that I made adjustments related to the Company's Sherco Units 1 and 2, the
4 Prairie Island EPU Recovery, the Jeffers Wind and Community Wind North
5 facilities, and the Company's AGIS initiative, I am making the associated
6 adjustments related to the Company's ADIT balance. For the Sherco Units 1 and
7 2, I am making an adjustment of (\$489,459). (WP-A11/A12). For the Prairie Island
8 EPU Recovery I am making an adjustment of (\$1,440,000) (WP-A-19). For the
9 Jeffers Wind and Community Wind North facilities, I am making an adjustment of
10 [trade secret data begins] [REDACTED] [trade secret data ends] as shown on
11 confidential NDPSC-5-76 Attachment B. For the AGIS initiative, I am making an
12 adjustment (\$108,092) (Accumulated Depreciation of \$443,000 times the
13 Composite Tax Rate of 24.40% or \$108,092).² My adjustments are shown on
14 Schedule DM-7.

15 D. Cash Working Capital (CWC)

16 Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO CASH
17 WORKING CAPITAL (CWC)?

18 A. The Company has proposed a CWC balance of (\$7,100,106) as shown on Exhibit
19 BCH-1 Revised Schedule 3A. The Company has included certain investments,
20 various non-plant assets and liabilities. (Exhibit BCH-1 page 29). For certain
21 components, the Company has used thirteen-month average balances projected
22 during the test year. For other components, the Company has used a simple
23 average of beginning and ending test year balances. The Company has calculated
24 its CWC by applying the results of a comprehensive lead/lag study to the projected
25 test year revenues and expenses. (Exhibit BCH-1 page 30-31).

26 Q. DO YOU HAVE ANY ADJUSTMENTS IN THE WAY THE COMPANY HAS
27 COMPUTED ITS CWC BALANCE?

² Exhibit BCH-1 Revised Schedule 3A.

1 **A.** No. I am accepting the Company's methodology but have adjustments related to
2 my recommended adjustment to the Company's proposed revenues and
3 expenses.

4 **Q.** **WHAT ARE YOUR ADJUSTMENTS?**

5 **A.** Based upon my adjustments to the Company's Rate Base components, the
6 Operating Income and the Operating Expenses, I have calculated a CWC balance
7 of (\$6,261,800). This is shown on Schedule DM-8.

8 **E. Non-Plant Assets and Liabilities**

9 **Q.** **WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO NON-PLANT**
10 **ASSETS AND LIABILITIES?**

11 **A.** The Company has proposed a Non-Plant Assets and Liabilities balance of
12 \$8,415,000 as shown on Exhibit BCH-1 Schedule 15. This balance represents
13 2021 calendar year estimates and any book/tax timing differences associated with
14 these items have been reflected in the determination of current and deferred
15 income tax provisions and ADIT balances. (Exhibit BCH-1 page 30).

16 **Q.** **DO YOU HAVE ANY ADJUSTMENTS RELATED TO THE COMPANY'S**
17 **PROPOSED NON-PLANT ASSETS AND LIABILITIES?**

18 **A.** In reviewing the WP P1-3 Unadjusted 2021, I note that the balance in the Non-
19 Plant Assets and Liabilities – 2021 Test Year was \$87,260,587, with an adjustment
20 of (\$1,083,000) reducing that balance to \$86,178,000. The balance allocated to
21 the North Dakota Electric Retail operations was \$6,353,000. An adjustment of
22 (\$67,000) reduces that amount to \$6,286,000. This is the balance that I am
23 recommending be included in the Non-Plant Asset and Liabilities account. My
24 adjustment is shown on Schedule DM-3.

25

26

27

28

1 **F. Regulatory Amortizations**

2 **Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS**
3 **REGULATORY AMORTIZATIONS?**

4 **A.** The Company proposed a balance of \$4,408,000 of Regulatory Amortization as
5 shown on Company Exhibit BCH-1 Schedule 15. This balance is comprised of the
6 following accounts:

7	(1) Electric Income Tax Tracker – ND	\$ 357,000
8	(2) PI EPU Deferral – ND	\$3,955,000
9	(3) NOL Tax Reform ADIT ARAM – ND	\$5,335,000
10	(4) RER PTC Amortization – ND	<u>(\$5,239,000)</u>
11	Total	\$4,408,000

12
13 **Q. WHAT DO THESE BALANCES REPRESENT?**

14 **A.** (1) The Electric Income Tax Tracker – ND represents the North Dakota share of
15 NSPM's tax and interest liabilities related to the 2010-2016 federal and state
16 income tax audits, which concluded in 2018 and 2020. This balance was driven
17 by audit assessments from the Internal Revenue Service (IRS) and Minnesota
18 Department of Revenue for Research & Experimentation (R&E) credits. (NDPSC
19 -5-59). These credits are shared with the North Dakota customers. The \$357,000
20 balance is shown on NDPSC 5-037 Attachment A and carries over to the
21 Company's Amortization Expense shown on Exhibit BCH-1 Schedule 6 and WP-
22 A24. The Company is amortizing the Income Tax Tracker over a three-year period.

23
24 (2) The PI EPU Deferred – ND of \$3,955,000 represents the unamortized balance
25 or undepreciated balance related to the Company's PI EPU project as I described
26 to in section A- EPIS of my testimony. (NDPSC-5-37 Attachment A).

27
28 (3) The NOL Tax Reform ADIT ARAM – ND balance of \$5,335,000 represents the
29 proposed amortization level included in the TCJA refund calculation. The balance
30 is being amortized over 23 years. (WP-A25) (NDPSC 5-037 Attachment A). The
31 methodology and amortization level was approved by the Commission under Case
32 No. PU-18-155 (Exhibit BCH-1 page 61).

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1 (4) The RER PTC Amortization – ND of (\$5,239,000) represents the proposal of
2 the Company with respect to change the way Production Tax Credits (PTC) are
3 accounted for prospectively. The Company proposes to normalize the benefits of
4 future PTCs by spreading the value of the PTCs over the life of the resource that
5 produces them, usually between twenty and twenty-five years, instead of the first
6 ten-years. (Exhibit BCH-1 page 39 and NDPSC-5-45). This is considered the
7 Levelized Credit Method (LCM). The Company requested that if the Commission
8 desires to normalize the PTCs going forward, then the use of the LCM should be
9 adopted for ratemaking purposes to evenly and fairly distribute the credits over the
10 full life of the resource. (Exhibit BCH-1 page 39-40). (WP-A21).

11 **Q. WHAT ADJUSTMENTS DO YOU HAVE REGARDING THE COMPANY'S**
12 **REGULATORY AMORTIZATIONS?**

13 **A.** I have two adjustments to the Company's Regulatory Amortizations. My first
14 adjustments is for item (1) Electric Income Tax Tracker – ND. The Company is
15 proposed to earn a return on the unamortized balance of \$357,000, and also
16 recover this through an amortization expense of \$143,000 over a three-year
17 period. This recovery is due to an audit assessment for the recovery of taxes and
18 interest liabilities related to disputed amounts (NDPSC 5-59 and Exhibit BCH-1
19 page 60). The Company should not be able to earn a return on taxes and interest
20 (carrying costs) and also recover the unamortized balance through the cost of
21 service (amortization expense). Typically these types of costs should only be
22 recovered through an amortization expense. There is no reason why the Company
23 should earn a return and carrying costs that are related to the payment of taxes
24 and interest liabilities (penalties). These audits concluded in 2018-2020. My
25 adjustment removes \$357,000 from the Company's Regulatory Amortization
26 balance. This adjustment is shown on Schedule DM-9.

27 **Q. WHAT IS YOUR NEXT ADJUSTMENT TO THE COMPANY'S REGULATORY**
28 **AMORTIZATION BALANCE?**

29 **A.** My next adjustment is to Item (2) – PI EPU Deferral – ND. Since I removed the
30 EPIS of \$4,109,000, I am removing the associated Regulatory Amortization

1 balance of \$3,955,000. My explanation for the reason of removal is addressed in
2 section A- EPIS of my testimony. This adjustment is shown on Schedule DM-9.

3 **Q. WHAT IS YOUR NEXT ADJUSTMENT TO THE COMPANY'S REGULATORY**
4 **AMORTIZATION BALANCE?**

5 **A.** My next adjustment is to Item (4) RER PTC Amortization – ND, which the Company
6 proposed to adjust credit from over the life of the resource that produces them,
7 (twenty to twenty-five) years, instead of the current ten-year period. (Exhibit BCH-
8 1 page 39 and NDPSC-45). The Company's proposal references the
9 Commission's and Commission's Staff desire to spread the value of these PTCs
10 (Exhibit BCH-1 page 39). Given this direction, I am accepting the Company's
11 proposal. However, the Company should confirm that these PTCs do not include
12 the proposed Community Wind and Jeffers Wind North projects which I have
13 recommended removal. Based upon the discovery responses (NDPSC-045, and
14 NDPSC 14-1) it is unclear how the Company developed its adjustment to its PTCs.

15

16

V. Operating Income Issues

17

A. Operating Revenues

18 **Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS OPERATING**
19 **REVENUES AT PRESENT RATES?**

20 **A.** The Company has proposed Operating Revenues at Present Rates of
21 \$245,976,308 as shown on Exhibit BCH-1 Schedule 3A. The Electric Retail
22 Revenues are comprised of \$206,415,835 as shown on WP R6 Back – Up. Other
23 Operating Revenues of \$39,560,473 (WP R5 Other Revenues) include Other
24 Operating Revenues of \$69,403,291 minus the Precedential Adjustments of
25 \$29,842,818.

26 **Q. HAS THE COMPANY EXPERIENCED ANY IMPACT RELATED TO THE COVID-**
27 **19 PANDEMIC?**

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1 **A.** Company witness Marks stated that at a high-level residential sales were strong in
2 2020 but not strong enough to offset the decline in the larger commercial and
3 industrial sector. (Exhibit JEM-1 page 7). Residential sales growth will slow down
4 in 2021 and commercial and industrial sales are expected to see modest overall
5 growth during 2021 from 2020, but overall sales will remain below 2019 sales.
6 (Exhibit JEM-1 page 7). The Residential sector increased in 2020 due to more
7 people spending time at home and in some cases working from home.

8 Commercial and Industrial sectors have been negatively impacted as businesses
9 were currently not operating at full capacity. (Exhibit JEM-1 page 7). Ms. Marks
10 has stated that some businesses were expected to close, and the Company has
11 seen a year-over-year loss of 40 customers as of August 2020, compared to flat-
12 year-over-year customer count as of December 2019. (Exhibit JEM-1 page 7). The
13 net effect is expected to be an overall flat Small Commercial and Industrial sales
14 in 2021 compared to 2020 levels. (Exhibit JEM-1 page 7).

15 Ms. Marks stated that the Company expects a small improvement in 2021 related
16 to the Large and Industrial sector. (Exhibit JEM-1 page 8). Ms. Mark has stated
17 that with time, the economy will recover, and businesses will return to normal
18 operations, or new businesses will be established to replace those that closed.
19 (Exhibit JEM-1 page 5).

20 **Q. WHAT WEATHER NORMALIZATION PERIOD HAS THE COMPANY USED TO**
21 **DEVELOP ITS SALES REVENUES?**

22 **A.** The Company has utilized a 20-year weather normalization period (Exhibit JEM-1
23 page 21). The use of a 20-year weather normalization period essentially takes into
24 consideration the historical sales, and predictor variables including economic
25 indicators, weather, and historical number of customers from January 2003
26 through May 2020. The model was simulated over the forecast period expressed
27 in 20-year average degree days). The short duration of COVID-19 does not really
28 affect revenues as the Company has used historic data through May 2020 (the
29 beginning of COVID-19). Exhibit JEM-1 page 21).

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1 **Q. WHAT TYPES OF OPERATING REVENUE IS INCLUDED IN THE COMPANY'S**
2 **PROPOSED LEVEL AT PRESENT RATES?**

3 **A.** As shown in response to NDPSC 5-038 Attachment A, the Company has included
4 such revenue accounts as Energy Revenues, Fuel Revenues and Rider
5 Revenues. The Company has included revenues associated with Interchange,
6 Trading and Transmission accounts, and Precedential Adjustments related to
7 Asset Trading, Non-Asset Trading and the proposed Depreciation Studies related
8 to Production and TD&G assets.

9 **Q. DO YOU HAVE ANY ADJUSTMENTS TO THE COMPANY'S OPERATING**
10 **REVENUES AT PRESENT RATES?**

11 **A.** Yes. I have one adjustment to the Company's Other Operating Revenues- Electric
12 Revenue Other. The Company has included \$1,863,345 of revenues related to
13 such items as late payment fees, return checks, miscellaneous service fees, rental
14 revenue, non-retail revenue and customer connection revenues. These types of
15 revenues typically fluctuate from year to year depending on various conditions,
16 terms, circumstances and events. As shown on Attachment A to NDPSC 5-38,
17 fluctuations can be identified for the years 2019 – 2021. Some of these revenues
18 are non-recurring. In this instance it is appropriate to average out these revenues
19 over a three-year period to smooth out and normalize these revenue adjustments.
20 A three-year average of these costs results in an increase of \$310,297 ($\$2,587,542$
21 $+ \$2,070,040 + \$1,863,345 / 3$). When added to the Company's proposed balance
22 of \$1,863,345, the balance becomes \$2,173,642. This is shown on Schedule DM-
23 10.

24 **Q. WHAT IS YOUR OTHER ADJUSTMENT TO THE COMPANY'S OPERATING**
25 **REVENUES AT PRESENT RATES?**

26 **A.** My other adjustment is to the Company's Precedential Adjustments of \$648,391
27 related to the Depreciation Study – Production related to the Sherco Units 1 and
28 2. As I removed the Accumulated Depreciation, Depreciation Expense, and other
29 related revenue requirement components, I am removing the associated revenues.
30 This adjustment is shown on Schedule DM-10.

1 **B. Operating and Maintenance Expenses**

2 **Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS OPERATING**
3 **AND MAINTENANCE EXPENSE?**

4 **A.** As shown on Exhibit BCH-1 Revised Schedule 3A, the Company proposed a total
5 Operating and Maintenance Expense (O&M) balance for the 2021 test year of
6 \$146,828,190.³ This balance is composed of various accounts related to Fuel and
7 Purchased Energy, Power Production/Regional Markets, Transmission,
8 Distribution, Customer Accounting/Customer Service, Sale/Economic
9 Development and Administrative and General. This balance includes the Company
10 specific adjustments in each of the accounts listed above, and as shown on Exhibit
11 BCH-1 Revised Schedule 6.

12 **Q. WHAT ADJUSTMENTS DO YOU HAVE WITH RESPECT TO THE COMPANY'S**
13 **OVERALL OPERATING AND MAINTENANCE EXPENSES?**

14 **A.** I have adjustments to certain of the Company's overall O&M Expense balance that
15 do not include specific adjustments the Company has made and proposed as
16 shown on Exhibit BCH-1 Revised Schedule 4. My overall adjustments to the
17 Company's certain O&M Expense incorporate the use of a three-year
18 normalization adjustment.

19 **Q. WHY ARE YOU USING A NORMALIZATION ADJUSTMENT TO CERTAIN OF**
20 **THE COMPANY'S OVERALL O&M EXPENSES?**

21 **A.** A review of the Company's O&M Expenses shows that certain of the Company's
22 balances for the periods 2018-2020 fluctuate and vary from year to year. In other
23 accounts, the balances during the same period appear to be abnormal and
24 irregular from what the Company is proposing to utilize and set in the test year
25 2021 period. In other areas there are negative balances or no prior costs
26 accounted for. I reviewed the Company's response to NDPSC DR-05-040
27 Attachment A which depicts the Company's O&M Costs by expense account. The
28 use of a three-year normalization period smooths out fluctuations in setting rates
29 going forward. Prior costs can also show and provide a trend of expenses that

³ Company updated its filing on March 26, 2021, which included an updated O&M Expense balance.

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1 were incurred by the Company to determine the reasonableness of the
2 adjustments in costs going forward.

3 The response to NDPSC DR-05-040 indicates that some of the expenses are
4 variable in nature and can change from period to period. It is appropriate to
5 normalize these types of costs to set rates in this proceeding. Finally, certain costs
6 are usually out of the Company's control in that they relate to outside vendors or
7 third-party providers.

8 **Q. DID YOU ASK THE COMPANY FOR AN EXPLANATION WHY CERTAIN**
9 **COSTS HAVE FLUCTUATED FROM YEAR TO YEAR?**

10 **A.** Yes. In response to NDPSC 14-2, I asked the Company for a description regarding
11 these fluctuations. The Company referred to the allocation of costs in its Cost
12 Assignment and Allocation Manual (CAAM). The Company used regional
13 allocators based upon customers in each jurisdiction (Minnesota and North
14 Dakota), and the related costs assigned to those jurisdictions. Some of the
15 allocators are also based upon revenues and allocate common utility costs for
16 commodity and bad debts. For Administrative and General Expenses, the costs
17 assigned were based upon a 12 coincidental peak demand allocator.

18 **Q. UTILIZING YOUR THREE-YEAR NORMALIZATION APPROACH WHAT IS**
19 **YOUR OVERALL ADJUSTMENT TO THE COMPANY'S O&M EXPENSE?**

20 **A.** As more fully reflected on Schedule DM-11, my three-year normalization
21 adjustments are an overall decrease of \$3,481,661, or an overall O&M Expense
22 balance of \$143,346,528, from the Company's proposed balance of \$146,828,189,
23 not including the specific adjustments as outlined in my testimony below under
24 each Expense category.

25 **Q. PLEASE ADDRESS YOUR AVERAGING ADJUSTMENTS UNDER EACH**
26 **EXPENSE CATEGORY.**

27 **A.** My averaging adjustment are as follows:

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1. Power Production Expense

Q. WHAT IS YOUR ADJUSTMENT TO THE COMPANY'S POWER PRODUCTION EXPENSE?

A. My first adjustment is to the Company Variable Production balance which the Company proposed a balance of \$510,248. This expense is variable in nature, and as such, varies from year to year. I utilized a three-year average for the periods 2018-2020 and compared the results to the Company's 2021 test year balance. My adjustment reduces this balance by \$24,584 to \$485,664 for the test year 2021. My second adjustment is to the Company's Regional Markets which the Company proposed a balance of \$685,188. This expense can be fixed or variable in nature and can vary from year to year. I utilized a three-year average for the periods 2018-2020 and compared the results to the Company's 2021 test year balance. My adjustment reduces this balance by \$31,479 to \$653,709 for the test year 2021. These adjustments are shown on Schedule DM-11.

2. Transmission Expense

Q. WHAT IS YOUR ADJUSTMENT TO THE COMPANY'S TRANSMISSION EXPENSE?

A. My adjustment is to the Company's Transmission Expense that is not part of the Interchange Agreement. The Company proposed a balance of \$10,151,545. This expense can vary from year to year. I utilized a three-year average for the periods 2018-2020 and compared the results to the Company's 2021 test year balance. My adjustment reduces this balance by \$605,930 to \$9,545,615 for the test year 2021. These adjustments are shown on Schedule DM-11.

3. Distribution Expense

Q. WHAT IS INCLUDED IN THE COMPANY'S DISTRIBUTION EXPENSE?

A. As stated in Ms. Bloch's testimony (Exhibit KAB-1) page 28, Distribution O&M Expenses are related to expenditures such as existing poles, wire assets, equipment maintenance, underground cable fault repairs, storm repairs, and inspections. Other expenses in this category are related to annual inspections of poles, vegetation management, and preventive damages by location underground

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1 electric facilities. The Company proposed a balance of \$8,529,179 for the 2021
2 test year period.

3 **Q. HAS THE COMPANY PROPOSED TO INCREASE ITS DISTRIBUTION**
4 **EXPENSES?**

5 **A.** Yes. According to Ms. Bloch, the Company is increasing its Distribution Expenses
6 by \$910,000 for the 2021 test year to account for an increase in O&M for its
7 Advanced Grid Intelligence and Security (AGIS) initiative. \$345,000 is related to
8 an increase in Vegetative Management, \$403,000 is related to Damage Preventive
9 costs and \$310,000 related to an increase in labor costs driven by the onboarding
10 of two North Dakota-based line workers and two North Dakota-based designers
11 (Exhibit KAB-1 page 32 and 34) (NDPSC-5-68).

12 **Q. WHAT HAS BEEN THE AVERAGE DISTRIBUTION EXPENSE BALANCE IN**
13 **PRIOR YEARS?**

14 **A.** As shown on Exhibit KAB-1 page 31, the Company's distribution expense, ranging
15 from \$6.8 million in 2013 to \$6.5 million in 2020, has remained relatively stable
16 over an 8-year period. Ms. Bloch attributed the relatively flat expense to the
17 Company's strong management practices. (Exhibit KAB-1 page 31). The Company
18 is now proposing to increase these costs to \$8.6 million or an increase of \$2.1
19 million.

20 **Q. WHAT WERE THE COMPANY'S REASONS TO FORECAST INCREASED**
21 **COSTS IN THIS EXPENSE CATEGORY?**

22 **A.** Ms. Bloch stated that the Company is currently negotiating contracts with vendors,
23 and due to COVID-19, the labor market for contracting jobs was tight, and the
24 insurance premiums to protect vendors from damages increased. The Company
25 stated that it is expecting an increase of work to be performed from 2021 to 2023
26 which is consistent with what the industry is seeing across the country. (Exhibit
27 KAB-1 page 33).

28 **Q. WHAT IS YOUR RESPONSE?**

29 **A.** I am recommending averaging out or normalizing these costs over a three-year
30 period from 2018-2020. With respect to Vegetation Management the Company is

1 on a four-year cycle and maintains necessary clearance due to vegetation growth
2 once every four years (NDPSC-5-64). The increase in the Company's Vegetation
3 Management of \$345,000 should be spread out over multiple years as these types
4 of costs will benefit more than one period. The increase in Damage Prevention
5 costs of \$403,000 should also be spread out over multiple years and not recovered
6 in a one-year period. Labor Costs increases of \$310,000 should be normalized as
7 the Company has indicated that employee count can vary, and it cannot predict
8 with complete certainty which positions will be hired and filled during 2021.
9 (NDPSC-5-20). With respect to the AGIS this is a long-term multi-year project
10 (Exhibit KAB-1 page 35). Given that I have removed the investment portion from
11 the Company's EPIS balance, the expense portion should not be recovered in this
12 proceeding. My specific adjustment is shown on my Schedule DM-15 and
13 addressed further below in my testimony.

14 **Q. WHAT IS YOUR ADJUSTMENT TO THE COMPANY'S DISTRIBUTION**
15 **EXPENSE?**

16 **A.** My adjustment to the Company's Distribution Expense is a reduction of \$1,426,175
17 or a balance of \$7,103,004, from the Company's proposed balance of \$8,529,179.
18 These adjustments are shown on Schedule DM-11

19 **4. Customer Accounting**

20 **Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS CUSTOMER**
21 **ACCOUNTING EXPENSE?**

22 **A.** The Company has proposed a Customer Accounting balance for the test year 2021
23 of \$4,008,156. These costs include Bad Debts, Customer related expenses and
24 Direct charges to North Dakota (NDPSC 5-40 Attachment A).

25 **Q. WHAT HAS BEEN THE COMPANY'S EXPERIENCE RELATED TO BAD**
26 **DEBTS?**

27 **A.** The Company had \$0 of bad debt expense in 2018, \$669,635 in 2019, \$1,217,760
28 in 2020 and \$1,145,546 in 2021. The Company has allocated about 5% of NSPM
29 total Electric Revenues to the North Dakota jurisdiction (NDPSC-5-8). The

1 Company indicated that it cannot attribute specific dollar amounts and the resulting
2 bad debt expense to a specific contributing factor. (NDPSC 5-8).

3 **Q. WHAT HAS BEEN THE COMPANY'S BAD DEBT EXPERIENCE RELATED TO**
4 **THE COVID-19 PANDEMIC?**

5 **A.** The Company has stated that incremental costs related to COVID-19 have
6 included \$500,000 for the North Dakota electric jurisdiction for additional bad debt
7 expense and \$100,000 of additional non-labor expense for cleaning/sanitizing,
8 physically distancing, safety materials, and costs to support remote work of about
9 \$100,000 for the North Dakota electric jurisdiction. (NDPSC-5-8). The Company
10 has included higher anticipated costs in 2021 to adjust the bad debt expense and
11 did not include any other incremental costs related to COVID-19 in the 2021 test
12 year.

13 **Q. WHAT ADJUSTMENTS DO YOU HAVE WITH RESPECT TO THE COMPANY'S**
14 **CUSTOMER ACCOUNTING EXPENSE?**

15 **A.** I am normalizing the Company's Bad Debt Expense over a three-year period. This
16 reduces the Company's Customer Accounting Expense from \$4,008,156 to
17 \$3,491,742 or a reduction of \$516,414. The Company stated that it has not
18 included any incremental costs related to COVID-19 in the 2021. The Company
19 cannot attribute specific dollar amounts and the resulting bad debt expense to a
20 specific contributing factor. The Company has allocated about 5% from NSPM to
21 the North Dakota electric jurisdiction. But these allocated costs are not reflected in
22 NDPSC 5-40 Attachment A. Given this wide fluctuation in costs from 2018 through
23 2020, it is appropriate to normalize these Bad Debts expenses going forward.
24 These adjustments are shown on Schedule DM-11.

25 **5. Customer Service & Information Expense**

26 **Q. WHAT IS YOUR ADJUSTMENT TO THE COMPANY'S CUSTOMER SERVICE**
27 **AND INFORMATION EXPENSE?**

28 **A.** I used a simple average of these costs for the periods 2018-2020. The Company
29 has proposed a balance of \$284,060 for the test year 2021. My three-year average

1 adjusts the balance to an increase of \$31,304 and a proposed 2021 balance of
2 \$315,364. This balance is shown on Schedule DM-11.

3 **6. Sale, Economic Development and Other Expenses**

4 **Q. DO YOU HAVE ANY ADJUSTMENTS TO THE COMPANY'S SALES,**
5 **ECONOMIC DEVELOPMENT AND OTHER EXPENSES?**

6 **A.** While I did not average out the Company's balance of \$118,859, I do have an
7 adjustment related to the Company's Economic Development Donations of
8 \$103,000. This adjustment will be addressed under Section I of my testimony
9 below. This balance is shown on Schedule DM-11.

10 **7. Administrative & General Expenses**

11 **Q. WHAT IS YOUR ADJUSTMENT TO THE COMPANY'S ADMINISTRATIVE AND**
12 **GENERAL EXPENSES?**

13 **A.** I am normalizing the Company's ECustMNND Border costs. In response to 14-2,
14 the Company stated that these costs represent costs assigned to jurisdiction based
15 upon a ND/MN customer allocation. I averaged out these expenses for the 2018-
16 2020 period to arrive at a normalized balance of (\$216,327). In the same manner
17 I averaged out the Company's EDemandProd costs, (\$229,574), EDirectND costs
18 of \$241,780 and the TwoFactorAlloc costs of (\$704,263). These adjustments total
19 a balance of (\$908,384). The Company has stated that these costs represent
20 assignment to jurisdiction (North Dakota) and based upon the SAP Profit Center. I
21 am of the opinion that these descriptions and reasons really don't show why these
22 costs fluctuate from year to years but is based upon a cost allocator related to
23 customers, revenues, commodity or shared allocations. For ratemaking purposes,
24 I believe that normalizing these costs is reasonable, given that these costs do tend
25 to vary from year to year.

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1 **C. Fuel and Purchased Energy Expenses**

2 **Q. WHAT SPECIFIC ADJUSTMENTS HAS THE COMPANY PROPOSED WITH**
3 **RESPECT TO ITS FUEL AND PURCHASED ENERGY EXPENSES?**

4 **A.** As shown on Exhibit BCH-1 Revised Schedule 6, the Company adjusted the Fuel
5 and Purchased Energy costs by (\$21,245,000) which is related to the removal of
6 asset and non-asset based fuel expenses. (NDPSC 5-39). The Company also
7 adjusted its Fuel and Purchased Energy Costs as referenced in its March 3, 2021
8 Electric Rate Case Update filing. The Company reduced its Fuel and Purchased
9 Energy Costs by \$3,045,438 due to a duplication of its expense of its gas demand
10 costs. The Company proposed an adjusted balance of \$54,351,000 as shown on
11 Exhibit BCH-1 Revised Schedule 6.

12 **Q. WHAT OTHER SPECIFIC ADJUSTMENT HAS THE COMPANY INCLUDED IN**
13 **ITS FUEL AND PURCHASED ENERGY?**

14 **A.** As outlined in response to NDPSC 5-76 and 80, and in Mr. Shaw's testimony
15 (Exhibit CJS-1 page 3), the Company has included and is requesting that the
16 Commission deem the Company's decision to enter into PPAs for the 187 MW
17 Solar Portfolio prudent and allow prospective recovery of the contract costs in the
18 Fuel Cost Rider (FCR). The Company has included [trade secret data begins]
19 [REDACTED] [trade secret data ends] of costs and has included these costs in
20 Exhibits BCH-1 Schedules 3A, 3B and 3C Fuel Reporting Line).

21 **Q. WHAT HAS THE COMMISSION RULED ON THIS PROJECT IN PRIOR**
22 **PROCEEDINGS?**

23 **A.** Mr. Shaw has stated that in the Company's prior case in PU-14-810, dated June
24 17, 2015, the Commission denied the Company's application and held that the
25 Company may not recover costs associated with the 187 MW Solar Portfolio
26 without specific approval from the Commission (Exhibit CJS-1 page 80-81).

27 **Q. WHERE IS THE 187 MW SOLAR PORTFOLIO LOCATED?**

28 **A.** The 187 MW Solar Portfolio (Marshall Solar is located near Marshall, Minnesota;
29 North Star Solar is located near North Branch, Minnesota, and MN Solar I is
30 located near Tracy, Minnesota). (Exhibit CJS-1 page 78).

1 **Q. WHY IS THE COMPANY ADDRESSING THIS ISSUE AGAIN IN THIS**
2 **PROCEEDING?**

3 **A.** Mr. Shaw has stated that the Commission should find the addition of the 187 MW
4 Solar Portfolio to be prudent and allow the Company to recover the costs
5 associated with the PPAs in the FCR. (Exhibit CJS-1 page 82). Mr. Shaw stated
6 that the Company proposed the acquiring the 187 MW Solar Portfolio primarily to
7 comply with the Minnesota's Solar Energy Standard (SES) Minn. Stat. §
8 216B.1691 Subd. 2f, which required the Company to serve 1.5 percent of its retail
9 customers with solar energy by the end of 2020 and establish a 10 percent solar
10 energy goal by 2030. (Exhibit CJS-1 page 82). Mr. Shaw stated that the Company
11 wanted to probe the market to obtain resources for compliance with Minnesota's
12 Solar Energy Standard (SES). (Exhibit CJS-1 page 83). Mr. Shaw stated that the
13 solar additions provide value by avoiding the need for fossil fuel generation and
14 market purchases, as well as by providing capacity (Exhibit CJS-1 page 84). Mr.
15 Shaw stated that an economic analysis performed by the Company determined
16 that the acquisition of the 187 MW Solar Portfolio was a prudent resource
17 acquisition to allow cost effective means to meet Minnesota's SES requirements.
18 (Exhibit CJS-1 page 86).

19 **Q. WHAT BENEFIT WILL THE INCLUSION OF THE 187 MW SOLAR PROJECT**
20 **PORTFOLIO HAVE ON NORTH DAKOTA CUSTOMERS?**

21 **A.** According to Mr. Shaw, the inclusion of the 187 MW Solar Project Portfolio will
22 benefit North Dakota customers by providing reasonably priced solar energy and
23 have the benefit of participating in the large integrated NSP system, given the very
24 modest cost impacts. (Exhibit CJS-1 page 88).

25 **Q. HAS THE COMPANY INCURRED COSTS RELATED TO THE 187 MW SOLAR**
26 **PORTFOLIO?**

27 **A.** According to Mr. Shaw, the Company has indicated it has under-recovered about
28 \$2.1 million of the costs since the projects were placed in service in 2014. (Exhibit
29 CJS-1 page 80, 81 and 90).

30 **Q. WHAT IS YOUR RECOMMENDATION?**

1 A. I am recommending that the 187 MW Solar Portfolio costs of [trade secret data
2 begins] [REDACTED] [trade secret data ends] be removed from rates. Given that
3 the Commission initially denied these costs in a prior proceeding (Case No. PU-
4 14-810) these costs should not be recovered from North Dakota's ratepayers in
5 this proceeding. Dr. Pavlovic provides further recommendations on this issue in
6 his testimony.⁴ My adjustments are shown on Schedule DM-12.

7 **D. Power Production Expenses**

8 **Q. WHAT SPECIFIC ADJUSTMENTS HAS THE COMPANY PROPOSED WITH**
9 **RESPECT TO ITS POWER PRODUCTION EXPENSES?**

10 A. The Company has proposed an adjustment of (\$271,000) related to Incentive
11 Compensation and (\$283,000) related to its Renewable Energy Rider (RER).
12 (Exhibit BCH-1 Schedule 4 – WP A15-A18 and WP A27, respectively. The
13 Company is proposing to include Incentive Compensation related to the (1) Long-
14 Term Portion, (LTI) excluding time based and environmental incentive; (2) Non-
15 Corporate incentive plan costs; and (3) all Annual Incentive Plan (AIP) costs above
16 20 percent of base pay. (Exhibit BCH-1 page 54). With respect to its RER, the
17 Company is proposing to remove all costs and revenues from the test-year
18 jurisdiction cost of service for the wind farms that will continue cost recovery in the
19 rider after implementation of final rates in this case. (Exhibit BCH-1 page 65).

20 **Q. WHAT ADJUSTMENTS DO YOU HAVE WITH RESPECT TO THE COMPANY'S**
21 **ADJUSTMENT TO INCENTIVE COMPENSATION AND ITS RER?**

22 A. I am accepting the Company's RER adjustment of (\$283,000). With respect to the
23 Company's Incentive Compensation, I am recommending that the Commission
24 maintain the recovery of the Company's 15 percent above base pay. This reduces
25 the Company's Incentive Compensation from \$271,000 to \$365,514, a reduction
26 of \$94,514. (see WP A18 page 4). My adjustment is shown on Schedule DM-13.

⁴ The replacement of certain types of generation/energy should be balanced with reliable resources now and in the future. The Arctic Event occurrence in February 2021, may impact the development of alternative generation given the extreme change in temperature and weather. It may not be prudent or reasonable to have these types of generation resources in lieu of more traditional generation resources.

1 Q. WHAT IS THE COMPANY'S REASONING TO PROPOSE A 20 PERCENT
2 RECOVERY OF INCENTIVE COMPENSATION?

3 A. Company witness Mr. Chamberlain stated that this adjustment will help the
4 Company recover the costs of employee compensation necessary to attract and
5 retain qualified employees. (Exhibit GPC-1 page 37). Mr. Chamberlain stated that
6 it can be expensive and time-consuming to fill vacancies, and the Company's LTI
7 helps retain key employees and, as the AIP, is necessary to Xcel Energy to remain
8 competitive in the labor market. (Exhibit GPC-1 page 37).

9 Q. HAS THE COMPANY PROVIDED THE RESULTS OF ITS KEY PERFORMANCE
10 INDICATORS (KPI) RECEIVED BY EMPLOYEES BY CATEGORY?

11 A. The Company was asked in response to NDPSC-5-15 to provide these Key
12 Performance Indicators and the results of the Company's scorecard. According to
13 the response to NDPSC-5-18 the Company provided its Corporate Scorecard KPI
14 allocated to the North Dakota Electric jurisdiction payouts. [trade secret data
15 begins] [REDACTED]
16 [REDACTED] [trade secret data ends]. In response to NDPSC-5-16, the
17 Company provided the results of the 2020 AIP payout, Environmental LTI and the
18 LTI for its Employee Group (Non-Bargaining Exempt, Non-Bargaining Non-
19 Executive Leadership and Non-Bargaining Executive BVP). These employee
20 were incentive eligible in 2020 for their respective programs receiving payment in
21 the first quarter of 2021, including NSPM and XES employees allocation to the ND
22 electric jurisdiction.

23 Q. WHY ARE YOU THEN RECOMMENDING MAINTAINING THE COMPANY'S 15
24 PERCENT ABOVE BASE PAY?

25 A. The Company claims that without LTI, AIP, and other incentive type compensation,
26 the Company will not be able to attract, maintain and retain employees especially
27 key employees who are responsible for Company's direction and strategy and
28 which can be expensive and time-consuming to fill. In response to NDPSC 5-19,
29 the Company provide a list of NSPM employees who had left the Company by
30 either retirement or by non-retirement. The number of employees of NSPM have
31 been declining since 2018. Using the Company's allocation factor shown on

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1 Exhibit BCH-1 Revised Schedule 13, of 6.1963% the number of employees which
2 have been assigned to the North Dakota jurisdiction in 2018, were 13. In 2020 the
3 number of employees who had left were 10. Out of these numbers, 7 employees
4 that left in 2018 were for non-retirement, and in 2020 only 3 employees related to
5 non-retirement have left. This is not a great outflow of employees leaving the
6 Company. In response to NDPSC 5-20, the Company stated that “like any other
7 large employer, the Company experiences a certain amount of employee turnover
8 every year. Employees leave Xcel Energy for a variety of reasons and in many
9 cases, the Company replaces them with new hires. This is a normal and expected
10 aspect of the Company’s operations and does not meaningfully impact rates.”
11 Therefore, the argument that the Company needs to increase its LTI, AIP and other
12 incentive type compensation to maintain its level of employees is not truly
13 accurate. If the Company wants to provide LTI and AIP incentive to its employees,
14 it is free to do so, so long as the shareholders provide the funding, and not the
15 North Dakota ratepayers. The Company can still be competitive in the labor
16 market without burdening North Dakota ratepayers with this incentive related
17 increase in costs. Finally, given the impact the COVID-19 Pandemic has had on
18 customers, it would be inappropriate to ask the North Dakota ratepayers to pay for
19 additional incentive type compensation costs.

20 **Q. WHAT IS YOUR OTHER ADJUSTMENT WITH RESPECT TO LABOR?**

21 **A.** In response to NDPSC 5-20, I asked the Company to provide a list of employees
22 who have been hired by the Company in 2020 and expected to be hired in 2021.
23 The Company’s response was that the Company cannot predict with complete
24 certainty which positions it will need to fill during 2021, but it can provide those
25 hires it currently anticipates making. The Company has provided a list of job titles
26 hired by NSPM and has provided a list of current opening in 2021. The Company
27 stated it cannot guarantee the anticipated hire data for the specific opening
28 (Attachment A – **CONFIDENTIAL DOCUMENT**). In this instance, I am
29 recommending a normalization of labor for all O&M labor by functional group. I
30 relied on the Company’s response to NDPSC 5-054 which shows the labor costs

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1 allocated to the North Dakota's jurisdiction. Given that the Company has stated
2 that Xcel Energy uses a variety of difference allocations that apply to labor costs,
3 and the costs of certain employees employed or allocated to the Company are not
4 allocated to North Dakota, it is appropriate to normalize labor costs. Labor costs
5 can vary from year to year in each of NSPM's service territories and depending on
6 the circumstances and the need to allocate labor, costs can vary. In averaging out
7 the Production O&M Labor costs, I used a three-year average (2018-2020), which
8 results in a balance of \$14,703,978. I compared this balance to the Company's
9 2021 Test Year balance of \$14,852,540 and adjusted it by \$148,562.

10 **Q. WHAT OTHER ADJUSTMENT HAS THE COMPANY PROPOSED WITH**
11 **RESPECT TO ITS POWER PRODUCTION?**

12 **A.** Without providing a dollar amount, the Company has proposed to request recovery
13 of its investment in the Mankato Energy Center, (MEC II) located in Mankato,
14 Minnesota. The Company is proposing to recover about [trade secret data
15 begins] [REDACTED] [trade secret data ends] assigned to the North Dakota
16 electric jurisdiction (NDPSC 5-76).

17 **Q. PLEASE DESCRIBE THE MEC II FACILITY AND HOW THIS POWER**
18 **PURCHASE AGREEMENT CAME ABOUT?**

19 **A.** The MEC II facility was completed by the Calpine Corporation (Calpine) in 2019,
20 via an expansion to include a second combustion turbine natural gas facility.
21 (Exhibit CJS-1 page 35). The Company has been under contract with Calpine
22 since 2006 and signed a 20-year PPA beginning in June 2019. Calpine sold the
23 MEC II facility (expansion rights) to Southern Power in late 2016. In late 2018, the
24 Company executed agreements with Southern Power to acquire the entire facility.
25 The Company filed an Advance Determination of Prudency (ADP) for the
26 purchase, but later withdrew the ADP application because the Company planned
27 instead to acquire MEC I and MEC II facility through a non-regulated affiliate. (CJS-
28 1 page 36). The Company's non-regulated affiliate has sold the facility to
29 Southwest Generation. The Company claims that it remains under contract to
30 purchase the capacity and output of MEC II under the MEC II PPA. (Exhibit CJS-

1 1 page 36). The Company requested an ADP for the MEC II PPA in 2015 in Case
2 No. PU-15-96, dated March 23, 2016. The Commission dismissed the Company's
3 application without prejudice to allow the Company to raise the issue with the
4 Commission again in the future. (Exhibit CJS-1 page 37). The Company is now
5 requesting that the Commission find the MEC II PPA prudent and allow recovery
6 of the capacity costs of the contracts in base rates. The Company claims that the
7 decision to add the MEC II PPA was prudent at the time the decision was made.
8 (Exhibit CJS-1 page 37).

9 **Q. WHAT IS YOUR RECOMMENDATION?**

10 **A.** I am recommending disallowance of the [trade secret data begins] [REDACTED]
11 [trade secret data ends] cost. As more fully discussed in Dr. Pavlovic's
12 testimony, the proposal by the Company to recover these costs in this proceeding,
13 with a test year ending December 31, 2021, should be disallowed. The Company's
14 proposal reflected capacity projections in the future, and not as of December 31,
15 2021, (the end of the test year). In order for costs to be included in the revenue
16 requirement, these costs should be known and measurable, prudent in nature and
17 used and useful in the provision of utility service. These costs are not. In addition,
18 these costs began in 2019, and collection of prior costs for future recovery is
19 considered retroactive ratemaking, which is prohibited in ratemaking. North
20 Dakota customers will not receive any benefit. Ratepayers should not be on the
21 hook for a business decision that did not pan out and which became ultimately
22 moot. The Company stated that given uncertain environmental regulatory
23 environment, it was prudent to secure capacity and position the NSP system for
24 an uncertain regulatory future. (Exhibit CJS-1 page 43). While the Company was
25 not short capacity from the 2017/2018 to 2019/2020 PRA Auctions, it argued that
26 the determination of need was prudent at the time the determination was made.
27 (Exhibit CJS-1 page 43). It is not prudent now. The Company essentially
28 abandoned the project in reaction to changing forecasts. (Exhibit CJS-1 page 44).
29 The Company argued for a conservative approach to for resource planning and
30 reasoned that customers would not be adversely affected from an unexpected
31 capacity deficit resulting from factors, such as rapid changes in demand, increased

1 reserve requirements and increased outages in aging resources. (Exhibit CJS-1
2 page 44). The Company argues that North Dakota customers should bear the risk
3 of acquiring capacity. I am of the opinion that the risk should stay with the
4 Company along with the costs associated with that risk, particularly when the
5 projected need for capacity is many years into the future. The Company is afforded
6 an opportunity, not a mandate, to recover all known and measurable costs, for
7 providing utility service. Commission Order PU-15-096 dated March 23, 2016,
8 indicated that a potential resource need was not expected until at least 2023 or
9 2024 (Case No. PU-15-96 at 2). Advocacy Staff testified that the PPA was not
10 prudent because the resource addition did not meet a near-term need. Preserving
11 the optionality in making a determination would change its approval of the Calpine
12 PPA (Case No. PU-15-96 at 3). My adjustment is shown on Schedule DM-13.

13 **E. Transmission Expenses**

14 **Q. WHAT SPECIFIC ADJUSTMENTS HAS THE COMPANY PROPOSED WITH**
15 **RESPECT TO ITS TRANSMISSION EXPENSES?**

16 **A.** The Company adjusted its Transmission Expenses by removing \$6.851 million
17 related to its Transmission Cost Recovery Rider (TCR) which is shown on Exhibit
18 BCH-1 Schedule 6 and in WP A28.

19 **Q. WHAT ARE YOUR ADJUSTMENTS?**

20 **A.** I am accepting the Company's adjustment to its TCR of \$6.851 million. My only
21 adjustment is to the Company's labor adjustment, which I addressed above under
22 Power Production section. I am recommending normalizing labor costs for the
23 same reasons discussed above, and since the Company cannot forecast which
24 positions will be filled in 2021 (NDPSC-5-20). I am recommending a normalization
25 of all O&M labor by functional group.⁵ The 2018-2020 three-year average for O&M
26 Labor Transmission and Regional Markets costs is \$1,094,755, which is an
27 adjustment to the Company's 2021 Test Year estimate of \$1,201,224

⁵ I relied on the Company's response to NDPSC-5-054 which show the labor costs allocated to the North Dakota's Electric Jurisdiction.

1 (Transmission) and \$17,952 (Regional Markets) by \$124,420. My adjustment is
2 shown on Schedule DM-14.

3 **F. Distribution Expenses**

4 **Q. WHAT SPECIFIC ADJUSTMENTS HAS THE COMPANY PROPOSED WITH**
5 **RESPECT TO ITS DISTRIBUTION EXPENSE?**

6 **A.** The Company has not proposed any specific adjustments to its Distribution
7 Expenses of \$8.529 million, shown on Exhibit BCH-1 Schedule 6 – Unadjusted, is
8 the same balance after adjustments.

9 **Q. WHAT ARE YOUR ADJUSTMENTS?**

10 **A.** As discussed previously in my testimony, I am normalizing distribution labor
11 expenses. The Company can neither determine which positions it needs nor
12 forecast the positions to be filled and given uncertain turnover along with the
13 various jurisdictional allocations, the Company cannot determine the overall
14 number of employees or how those employees might be allocated. (NDPSC-5-20).
15 I relied on the Company's response to NSPSC 5-54, Attachment B, which shows
16 the labor costs allocated to the North Dakota Electric jurisdiction. The 2018-2020
17 three-year average for distribution labor costs is \$3,415,108, which is an
18 adjustment to NSP's estimate of (\$1,025,882).

19 **Q. WHAT OTHER ADJUSTMENTS DO YOU HAVE WITH RESPECT TO THE**
20 **COMPANY'S DISTRIBUTION EXPENSE?**

21 **A.** Included in the Company's Distribution Expenses are costs related to the
22 Company's AGIS initiatives. (NDPSC 5-73), and include \$150,000 for AMI,
23 \$80,000 for FAN, \$210,000 for ADMS and \$340,000 for other for a total Distribution
24 Expense balance of \$780,000. Given that I am recommending the removal of the
25 AGIS initiative costs from the Company's EPIS balance, I am removing the portion
26 of AGIS related to Distribution Expenses. My reasons for the removal are
27 discussed in the Rate Base – IV section of my testimony. My adjustments are
28 shown on Schedule DM-15.

29

1

G. Customer Accounting Expenses

2 **Q. WHAT SPECIFIC ADJUSTMENTS HAS THE COMPANY PROPOSED WITH**
3 **RESPECT TO ITS CUSTOMER ACCOUNTING EXPENSES?**

4 **A.** The Company did not propose any specific adjustment to its Customer Accounting
5 Expenses. The Company's \$4.008 million Unadjusted Balance as shown on
6 Exhibit BCH-1 Schedule 6, is the same balance after all proposed adjustments.

7 **Q. WHAT ARE YOUR ADJUSTMENTS?**

8 **A.** As I discussed previously in my testimony, I am normalizing Customer Accounts
9 labor expense. The Company can neither determine which positions it needs nor
10 forecast the positions to be filled and given uncertain turnover along with the
11 various jurisdictional allocations, the Company cannot determine the overall
12 number of employees or how these employees might be allocated. (NDPSC-5-20).
13 I relied on the Company's response to NDPSC-5-54, Attachment B, which shows
14 the labor costs allocated to the North Dakota Electric jurisdiction. The 2018-2020
15 three-year average for Customer Accounting labor costs is \$850,397, which is an
16 adjustment to NSP's estimate of (\$17,846).

17 **Q. WHAT IS YOUR FINAL ADJUSTMENT TO THE COMPANY'S CUSTOMER**
18 **ACCOUNTING EXPENSE?**

19 **A.** Included in the Company's Customer Accounting Expense are costs relate to the
20 Company's AGIS initiative, (NDPSC5-73) and includes \$100,000 related to AMI.
21 Given that I am recommending removing the portion of the AGIS initiative costs in
22 the Company's EPIS balance, I am removing the portion of AGIS related to
23 Customer Accounting Expenses. My reasons for the removal are discuss in the
24 Rate Base – IV section of my testimony. My adjustment is shown on Schedule DM-
25 16.

26

H. Customer Service & Information Expenses

27 **Q. WHAT SPECIFIC ADJUSTMENTS HAS THE COMPANY PROPOSED WITH**
28 **RESPECT TO ITS CUSTOMER SERVICE & INFORMATION EXPENSES?**

1 A. The Company did not propose any specific adjustments to its Customer Service &
2 Information Expenses. The Company's \$284,000 Unadjusted Balance as shown
3 on Exhibit BCH-1 Schedule 6, is the same balance after all proposed adjustments.

4 Q. **WHAT ARE YOUR ADJUSTMENTS?**

5 A. I am accepting the Company's balance of \$284,000 with respect to its Customer
6 Service and Information Expenses, as shown on Schedule DM-17.

7 **I. Sales, Economic Development & Other Expenses**

8 Q. **WHAT SPECIFIC ADJUSTMENTS HAS THE COMPANY PROPOSED WITH**
9 **RESPECT TO SALES, ECONOMIC DEVELOPMENT AND OTHER EXPENSES?**

10 A. As shown on Exhibit BCH-1 Schedule 4 and Schedule 6, the Company proposed
11 an Unadjusted Balance related to Sales, Economic Development and Other
12 Expenses of \$16,000. To that balance, the Company added \$103,000 related to
13 Economic Donations to arrive at an adjusted balance of \$119,000.

14 Q. **WHAT IS INCLUDED IN THE COMPANY'S \$103,000 ECONOMIC**
15 **DEVELOPMENT DONATIONS?**

16 A. Company Witness Mr. Halama (Exhibit BCH-1 page 53) stated that the Company
17 makes contributions to a number of regional and local economic development
18 organizations positioned to combine resources for the purposes of maintaining and
19 improving the long-term economic health of communities in its service territory or
20 retaining employment opportunities and expanding the state and local tax base. In
21 response to NDPSC 5-51, these costs provide financial and collaborative support
22 to local, regional and state organizations. It is an estimate. These costs are used
23 to assist in the strategic advancement of the communities served by the Company
24 for job creation, GDP growth and the overall social well-being for individuals and
25 businesses. There is no further breakdown or description of these donations.

26 Q. **WHAT IS YOUR POSITION ON ECONOMIC DEVELOPMENT DONATIONS?**

27 A. I do not believe that ratepayers should pay for these types of costs in rates. These
28 expense items are akin to charitable contributions. The Company is a utility
29 company providing utility service to certain parts of North Dakota. The Company

1 should not be expensing costs related to non-utility type services, nor be in a
2 position to support regional and local economic development. These type of
3 initiatives should be provided at the State and Local or even at the Federal level.
4 Additionally, ratepayers do not have a say in what type of donations they are
5 paying for, or whether ratepayers receive any benefit for these contributions.
6 These types of costs should not be included in the revenue requirement proposed
7 by the Company. The Company should pay for these costs, below the line, and
8 receive the tax benefits through the corporate entity.

9 **Q. WHAT IS YOUR RECOMMENDATION?**

10 **A.** I am recommending removal of the \$103,000 of Economic Development Donations
11 from the Company's Sales, Economic Development and Other Expenses balance.
12 This is shown on Schedule DM-18.

13 **J. Administrative & General Expenses**

14 **Q. WHAT SPECIFIC ADJUSTMENTS HAS THE COMPANY PROPOSED WITH**
15 **RESPECT TO ITS ADMINISTRATIVE AND GENERAL EXPENSES?**

16 **A.** As shown on Exhibit BCH-1 Schedule 4 and 6, the Company proposed an
17 Unadjusted Balance of \$17.885 million, and an Adjusted Balance of \$16.782
18 million. These adjustments reflect Precedential Adjustments which the Company
19 has not changed from the Commission's Order in the Company's previous
20 completed electric rate cases (Exhibit BCH-1 page 51). The Company has also
21 reflected Ratemaking Adjustments that relate to specific adjustments in this instant
22 proceeding. I will address each of these Precedential and Ratemaking
23 Adjustments below.

24 **Q. WHAT IS YOUR FIRST ADJUSTMENT?**

25 **A.** As I normalized labor expenses under the Company's prior expense balances, I
26 am normalizing here under Administrative & General Expenses. My arguments are
27 the same as discussed above. I relied on the Company's response to NDPSC 5-
28 54, Attachment B , which shows the labor costs allocated to the North Dakota
29 Electric jurisdiction. The results is an average balance of \$4,239,297. I compared

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1 this balance to the Company's 2021 balance of \$5,009,357 and arrived at an
2 adjustment of (\$770,060). My adjustment is shown on Schedule DM-19.

3 **Q. WHAT SPECIFIC PRECEDENTIAL ADJUSTMENTS HAS THE COMPANY**
4 **PROPOSED IN THIS PROCEEDING?**

5 **A.** The Company has proposed the following Precedential Adjustments:

6 **Precedential Adjustments**

7	Advertising -	(\$237,734)	WP A1
8	Association Dues -	(\$ 21,599)	WP A2
9	Aviation -	(\$ 99,354)	WP A3
10	Customer Deposits -	\$ 2,814	WP A4
11	Employee Benefits -	(\$ 81,941)	WP A5
12	Pension Non-Qualified SERP -	(\$ 17,186)	WP A6

14 **Q. WHAT ADJUSTMENTS DO YOU HAVE REGARDING THE COMPANY'S**
15 **PRECEDENTIAL ADJUSTMENTS?**

16 **A.** I have the following balances to the Company's Precedential Adjustments, which
17 are reflected on Schedule DM-19:

18	a.	Advertising -	(\$ 274,514)
19	b.	Association Dues -	(\$ 35,815)
20	c.	Aviation -	(\$198,708)
21	d.	Customer Deposits -	\$ 1,618
22	e.	Employee Expenses	\$576,491
23	f.	Pension Non-Qualified SERP	\$120,937

24
25
26 **a. Advertising**

28 **Q. WHAT ADJUSTMENTS DO YOU HAVE WITH RESPECT TO ADVERTISING**
29 **EXPENSES?**

30
31 **A.** I am recommending an overall reduction of \$36,780 related to Advertising
32 Expenses, or reduction balance of \$274,514. (WP A1). The Company stated in
33 response to NDPSC 5-50 that all of the Advertising Expenses reflect six months of
34 actual and six months of forecasted expenses by type. These costs represents
35 general advertising, conservation, customer programs and safety inserts . The

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1 Company has provided a breakdown of these general advertising costs, which
2 were related to brand image, sponsorships and general in nature. While the
3 Company has not specifically described nor identified its overall General
4 Advertising Expense balance, I am recommending maintaining these costs at the
5 balance of (\$274,514). Until such as time as the Company can identify these costs
6 more precisely, and describe these costs in more detail, these costs should remain
7 at the 2020 reduction level.

8
9 b. Association Dues

10
11 **Q. WHAT ADJUSTMENTS DO YOU HAVE WITH RESPECT TO ASSOCIATION
12 DUES?**

13
14 **A.** I am recommending a reduction of \$14,216, and an overall reduction of \$35,815.
15 The Company stated in response to NDPSC 5-50, that the Association Dues were
16 based upon an allocation of 2019 actual allowances, applied to the 2021 test year
17 budget. (WP A2). This was done to provide consistency and comparability across
18 the test year and to base the adjustment on the last year of actual data consistent
19 with the employee expenses adjustment. The Company has not provided a
20 breakdown of these costs. As I indicated under my Advertising adjustment, until
21 such time as the Company can provide and identify these costs more precisely, I
22 am recommending maintaining these costs at the 2020 level.

23
24 c. Aviation

25
26 **Q. WHAT HAS THE COMPANY PROPOSED REGARDING ITS AVIATION
27 EXPENSES?**

28
29 **A.** The Company proposed to include 50% of the aviation – related costs allocated to
30 the North Dakota jurisdiction. These costs were incurred in lieu of commercial
31 aviation transportation and help facilitate the efficiency use of executive time. (WP
32 A3). The Company has removed \$99,354 of Aviation related expenses.

1 **Q. WHAT ADJUSTMENTS DO YOU HAVE?**

2 **A.** I am recommending removing all Aviation Costs from rates, an adjustment of
3 \$198,708. The Company completed an aviation cost benefit analysis comparing
4 the use of corporate aviation to commercial transportation, which the Company
5 deemed to be cost effective. (NDPSC 5-50). I am of the opinion that the
6 Company's cost benefit analysis does not benefit ratepayers in North Dakota, as
7 indicated in response to NDPSC-5-050 Attachment A. Page 17 of the Summary
8 of Results reflects a higher Corporate Cost to that of Commercial costs by \$2.010
9 million. The Company stated that non-executives use corporate aviation in
10 addition to the executive of the Company. However, the Company's Attachment
11 B does not provide meaningful information with respect to non-executive travel,
12 nor the use or need for corporate travel. In my opinion, the Company defines cost
13 benefit as a benefit to the Company, and not a benefit to the ratepayer. The
14 Company should only recover travel expenses based upon commercial airline
15 costs (NDPSC 5-050 Attachment A page 17 of 21). These commercial costs are
16 much less costly in price than the use of corporate aircraft.

17
18 d. Customer Deposits

19
20 **Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO CUSTOMER**
21 **DEPOSITS?**

22
23 **A.** The Company proposed an adjustment of \$1,618 related to Customer Deposits.
24 This is shown on Exhibit BCH-1 Schedule 4 and on WP A4 page 2 of 7.

25 **Q. WHAT ADJUSTMENTS DO YOU HAVE?**

26 **A.** I am accepting the Company's Customer Deposit adjustment of \$1,618. However,
27 when adding up the Company's Precedential adjustments shown on Exhibit BCH-
28 1 Schedule 4, a balance of \$456,196 is computed. This is different from what the
29 Company has shown on Exhibit BCH-1 Schedule 6, Line 17 of \$455,000. Whether
30 the difference is due to rounding or some other adjustment, I adjusted the
31 Company's Customer Deposit Balance to \$2,814 and subtracted \$1,196 to arrive
32 at a balance of \$1,618 which reflects the Company's adjusted balance.

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e. Employee Expenses

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS EMPLOYEE EXPENSES?

A. The Company has proposed a reduction of \$81,941 to employee related non-labor expenses, which includes costs such as business related meals, active healthcare, life and disability insurance, retiree medical and worker compensation (NDPSC 12-2).

Q. WHAT ADJUSTMENTS DO YOU HAVE WITH RESPECT TO THE COMPANY'S EMPLOYEE EXPENSES?

A. In the same manner as I normalized the Company's labor in response to NDPSC 5-54 Attachment B, I am normalizing the associated non-labor costs for the same periods (2018-2020). My normalized adjustment matches the level of employees with the associated expenses and benefits for the same period. In Company response to NDPSC 12-2, the Company provided three-years of O&M Non-labor costs for NSPM Electric and the allocation portion to the North Dakota jurisdiction. I normalized the costs under each functional group and adjusted the balance to the Company's 2021 test year balance of \$8,084,701 to my three-year average costs of \$8,881,256, an adjustment of \$796,555. I computed a ratio of Employee Expenses and Pension Costs (in section f. below) to total and arrived at a ratio of 82.66% to Employee Expenses and 17.34% to Pension Expenses. I multiplied the \$796,555 by 82.66% to arrive at an adjustment of \$658,432, and a balance of \$576,491. This is shown on Schedule DM-19.

f. Pension Non-Qualified SERP

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO PENSION NON-QUALIFIED SERP?

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1 A. The Company has proposed a reduction of \$17,186 which excludes all non-
2 qualified pension expenses related to the Company's Supplemental Executive
3 Retirement Plan (SERP).

4 Q. **WHAT ADJUSTMENTS DO YOU HAVE?**

5 A. I averaged the Company's Pension Non-Qualified SERP costs for the period 2018-
6 2020 utilizing the same methodology of Pension Expenses to expenses (17.34%)
7 and multiplied that ratio to \$796,555 to arrive at an adjustment of \$138,123.⁶ This
8 produces an adjustment of \$138,122 and a balance of \$120,936. And in the same
9 manner as I normalized Labor over the same period, I am also normalizing the
10 Company's Pension Non-Qualified SERP costs. My adjustment is shown on
11 Schedule DM-19.

12 Q. **WHAT ARE THE OTHER SPECIFIC ADJUSTMENTS HAS THE COMPANY**
13 **PROPOSED IN THIS PROCEEDING?**

14 A. The Company has proposed three Ratemaking Adjustments:

15

16

Ratemaking Adjustments

17	a.	Dues – Chamber of Commerce	\$20,000	WP A20
18	b.	Foundation and Other Donations	\$68,000	WP A14
19	c.	Incentive Compensation	(\$736,000)	WP A15-18

20 Q. **WHAT ADJUSTMENTS DO YOU HAVE REGARDING THE COMPANY'S**
21 **RATEMAKING ADJUSTMENTS ABOVE?**

22 A. I adjusted the Company's Ratemaking Adjustments per above and which is
23 reflected on Schedule DM-19.

24	a.	Dues – Chambers of Commerce	(\$0)
25	b.	Foundation and Other Donations	(\$0)
26	c.	Incentive Compensation	(\$988,241)

27

28

29

⁶ This is shown on Company response to NDPSC-12-002.

1 a. Dues – Chambers of Commerce
2

3 **Q. WHAT HAS THE COMPANY INCLUDED IN ITS DUES - CHAMBERS OF**
4 **COMMERCE?**

5 **A.** The Company has included 50% of its forecasted Dues – Chambers of Commerce
6 costs as a 2021 test year expense (WP-14). Company witness Mr. Halama stated
7 that these costs provide an essential link between the Company and the
8 communities it serves and facilitate improved utility service (Exhibit BCH-1 page
9 56). Mr. Halama stated that because membership in these organizations provide
10 benefits to all utility customers, recovery of membership dues paid to Chambers of
11 Commerce is appropriate. (Exhibit BCH-1 page 56).

12 **Q. WHAT ARE YOUR ADJUSTMENTS?**

13 **A.** I am recommending no recovery because this type of cost does not benefit North
14 Dakota ratepayers. This cost mainly serves to advance the policy positions before
15 State and Governmental agencies and to communicate its corporate citizenship
16 initiatives. Ratepayers should not be required to pay for such costs which provide
17 no benefit to utility service.

18
19 b. Foundation and Other Donations

20 **Q. WHAT HAS THE COMPANY INCLUDED IN ITS FOUNDATION AND OTHER**
21 **DONATIONS?**

22 **A.** The Company has included \$68,000 of costs related to Foundation and Other
23 Donations. Company witness Mr. Halama stated that the Company is proposing
24 50% of corporate charitable contributions benefiting the State of North Dakota in
25 the test year. Mr. Halama stated that an analysis was performed on contribution
26 details to ensure that only amounts contributed to charities and institutions that
27 could be associated with the Company's electric service territory in the North
28 Dakota jurisdiction were included in the cost of service. (Exhibit BCH-1 page 54).

29

1 **Q. WHAT IS YOUR RECOMMENDATION?**

2 **A.** I am recommending that zero dollars related to Foundation and Other Donations
3 be included in the cost of service. The Company has not provided a breakdown
4 of these costs, but rather allocations of costs between and among NSPM and its
5 subsidiaries. Charitable Contributions in general, should be removed from the
6 Company's cost of service because ratepayers do not have any say of what type
7 of contributions they are paying for. These types of payments do not benefit
8 ratepayers, and as I stated above in the Chambers of Commerce section, only
9 benefits the Company as being good corporate citizens. These costs should be
10 funded below the line by the shareholders of the Company and receive a tax
11 benefit through the corporate entity. The Company stated that these costs *benefit*
12 the State of North Dakota, and not specifically the *ratepayers* of the Company or
13 the service territories the Company provides electric service to. The Company
14 does not have the right to make others pay for charitable contributions, especially
15 those costs that do not provide specific benefits to its ratepayers.

16 c. Incentive Compensation

17 **Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS INCENTIVE**
18 **COMPENSATION?**

19 **A.** The Company has proposed an adjustment of (\$736,000) related to Incentive
20 Compensation. The Company is proposing to include Incentive Compensation
21 costs above 20 percent of base pay. (Exhibit BCH-1 page 54). The Incentive
22 Compensation costs are related to the Company's LTI, AIP and non-corporate
23 incentive plan costs.

24 **Q. WHAT IS YOUR RECOMMENDATION?**

25 **A.** I am recommending that the Commission maintain the recovery of the Company's
26 15 percent above base pay, rather than increasing this to 20 percent. This
27 increases the reduction from \$736,000 to \$988,242, or \$252,241. (WP A18 page
28 4). My arguments for maintaining the 15 percent of base pay is included above
29 under the C – Power Production Expenses.

1

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K. Depreciation Expenses

3

Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO DEPRECIATION EXPENSE?

4

5

A. The Company proposed an Unadjusted Depreciation Expense balance of \$48,499,000 as shown on Exhibit BCH-1 Schedule 6. The Company proposed Depreciation Expense of \$54,544,171, after making \$6,045,171 of adjustments to the Unadjusted Depreciation Expense balance in the test year period. (Exhibit BCH-1 Schedule 6). Company witness Mr. Moeller stated that the Company is requesting a revision to its remaining lives, net salvage rates, retirement curves and depreciation rates for its production, transmission, distribution, general and intangible assets. (Exhibit MPM-1 page 20). The Company made the following adjustments to derive its proposed Depreciation Expense balance:

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Unadjusted Balance	\$48,499,000
<u>Decommissioning (Nuclear):</u>	
Monticello	\$ 798,067
Prairie Island Unit 1	\$ 732,118
Prairie Island Unit 2	\$ <u>443,304</u>
Sub-total	\$ 1,973,489
<u>Depreciation Study – Includes Sherco Units 1 and 2:</u>	
Remaining Life (Hydro/Other/Steam) ⁷	\$ 4,422,684
TD&G	\$ <u>437,998</u>
Sub-Total	\$ 4,860,682
Rider – RER	\$ (686,000)
Rider – TCR	\$ <u>(103,000)</u>
Adjusted Balance	\$54,544,171

Q. WHAT IS YOUR INITIAL ADJUSTMENT RELATED TO THE COMPANY'S DEPRECIATION EXPENSE?

A. My first adjustment is a reduction of (\$379,919), which reflects Mr. Garren's adjustment related to his recommending proposed depreciation rates and

⁷ The Depreciation Study relates to the shortened lives of the Company's Sherburne County Generating Station (Sherco) located in Becker, Minnesota. These are coal-fired units which were placed in service in 1976 (Unit 1) and 1977 (Unit 2).

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1 expenses for production, transmission, distribution and general categories. Mr.
2 Garren's recommendation is shown on his Schedules JSG-1 and 2.

3 **Q. WHAT OTHER ADJUSTMENTS DID YOU MAKE WITH RESPECT TO THE**
4 **COMPANY'S PROPOSED DEPRECIATION EXPENSE BALANCE?**

5 **A.** My first adjustment is to the Company's proposed Jeffers Wind and Community
6 Wind North Facilities as outlined in Mr. Shaw's testimony (Exhibit CJS-1 page 2)
7 and the rate impacts as shown on NDPSC-5-76. As I testified earlier under the
8 Electric Plant in Service, about my recommendations to remove Jeffers Wind and
9 Community Wind North Facilities from the Company's plant in service balance, I
10 am also removing the associated depreciation expenses of [trade secret data
11 begins] [REDACTED] [trade secret data ends].

12 **Q. WAS THIS ADJUSTMENT PART OF THE COMPANY'S ADJUSTMENTS TO ITS**
13 **DEPRECIATION EXPENSE BALANCE?**

14 **A.** No. It was not specifically broken down on Exhibit BCH-1 Schedules 4, 5 or 6. The
15 response to Confidential NDPSC-5-076 provided the detail of this proposal.

16 **Q. WHAT IS YOUR NEXT ADJUSTMENT WITH RESPECT TO THE COMPANY'S**
17 **DEPRECIATION EXPENSE?**

18 **A.** I removed the Depreciation Expense associated with AGIS since I removed the
19 costs of AGIS from rate base. The Company proposed a 10% Depreciation Rate
20 (NDPSC 12-16). My adjustment is therefore, \$443,000. My arguments for removal
21 are upon my Rate Base IV section of my testimony.

22 DECOMMISSIONING – NUCLEAR

23 **Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS**
24 **ADJUSTMENT RELATED TO THE DECOMMISSIONING COSTS FOR ITS**
25 **MONTICELLO NUCLEAR AND THE PRAIRIE ISLAND NUCLEAR UNITS 1 AND**
26 **2 GENERATING FLEETS?**

27 **A.** The Company has proposed to increase its annual nuclear decommissioning
28 accrual from \$276,513⁸ to \$2,250,002, or an increase of \$1,973,489. (Exhibit

⁸ This was set in Case No. PU-12-813

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1 MPM-1 page 42, WP A10). For the Monticello and the Prairie Island Units 1 and
2 2, (Nuclear Decommissioning costs), the Company is proposing to increase the
3 accrual which will fund the nuclear decommissioning, so as to provide sufficient
4 funds to cover the final removal costs for the Company's three nuclear units.
5 (NDPSC 12-12). (Exhibit MPM-1 page 42). The amount collected through general
6 rates are deposited externally in a trust fund per the Nuclear Regulatory
7 Commission (NRC) rules. The annual accruals are calculated from a detailed
8 engineering cost estimate for removal of the plant and of storage of the fuel until
9 the federal government takes possession of all the fuel assemblies. These accruals
10 are then invested by professional asset managers in a risk-mitigated strategy to
11 grow the accrual amount while hedging losses. (Exhibit MPM-1 page 42).

12 Company witness Mr. Moeller stated that nuclear decommissioning accruals are
13 calculated at the jurisdictional level and not at the total NSPM Company level.
14 (Exhibit MPM-1 page 42). Mr. Moeller stated that the increase is driven by a \$1.6
15 million earnings shortfall of the trust, and increase in the inflation rate, and an
16 increase in the amount allocated to North Dakota (Exhibit MPM-1 page 42-43).

17 **Q. PLEASE DESCRIBE THE MONTICELLO AND PRAIRIE ISLAND NUCLEAR**
18 **GENERATING UNITS?**

19 **A.** As more fully described in Mr. Moeller's testimony (Exhibit MPM-1 page 7-8), the
20 Monticello is a single-unit boiling water reactor which was originally licensed by the
21 NRC in 1970. In 2016, the NRC approved a license for the facility to operate
22 through 2030. The Company intends to seek a license extension to allow the plant
23 to operate through 2040, or 10 years into a 20-year license renewal. (Exhibit MPM-
24 1 page 8)(NDPSC 5-077). Prairie Island is a two-unit pressurized water reactor,
25 which was initially licensed in 1973 (Unit 1) and 1974 (Unit 2). Prairie Island's Unit
26 1 and Unit 2 licenses were set to expire in 2013, and 2014, respectively. However,
27 the NRC approved licenses for these units one and two to operate until 2033 and
28 2034, respectively.

1 Q. WHAT IS THE COMPANY REQUESTING OR ASKING THE COMMISSION TO
2 DETERMINE WITH RESPECT TO THE MONTICELLO AND THE PRAIRIE
3 ISLAND UNITS 1 AND 2?

4 A. The Company is requesting that the Commission approve the increased costs
5 related to the Monticello and Prairie Island nuclear decommissioning trusts.
6 (Exhibit MPM-1 page 42), and the increased costs related to the Prairie Island
7 Nuclear generating stations costs (Units 1 and 2) of \$732,118 and \$443,304,
8 respectively to cover and fund the increased annual nuclear decommissioning
9 trust.

10 Q. DO YOU HAVE ANY ADJUSTMENTS REGARDING THE COMPANY'S
11 PROPOSED DECOMMISSIONING COSTS FOR MONTICELLO AND THE
12 PRAIRIE ISLAND UNITS 1 AND 2?

13 A. No.

14 DEPRECIATION STUDY – INCLUDING SHERCO UNITS 1 AND 2

15 Q. WHAT IS THE COMPANY PROPOSING WITH RESPECT TO ITS
16 DEPRECIATION STUDY INCLUDING THE RELATED TO SHERCO UNITS 1
17 AND 2?

18 A. The Company has proposed to retire Sherco Units 1 and 2 and has requested that
19 the Commission allow the Company to adjust the remaining lives of the plant for
20 depreciation purposes, to reflect the shortening of the remaining lives for Sherco
21 1 and 2 to retire in 2026 and 2023, respectively. (Exhibit CJS-1 page 2). (WP A11).
22 (Exhibit MPM-1 page 25). Consistent with the decision in South Dakota (Sherco 1
23 and 2 remaining lives through 2022), and Minnesota (Sherco remaining life through
24 2026 and Sherco 2 remaining life through 2023), the Company is requesting similar
25 adjustments to the remaining lives of these units in North Dakota. (Exhibit CJS-1
26 page 7-8). The Company is also proposing to adjust the remaining lives of its Other
27 Production, Transmission, Distribution, General and Intangible (TD&G) lives.
28 (Exhibit MPM-1 page 21).

29 Q. WHAT DEPRECIATION STUDY ADJUSTMENTS ARE YOU ADDRESSING
30 AND TESTIFYING TO?

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1 **A.** My adjustments and my testimony relates to the Company's proposal to shorten
2 the lives of the Company's Sherco Units 1 and 2 Steam Production. I am also
3 making adjustments to transmission and distribution depreciation expenses. I am
4 not making any adjustments related to the Company's Other proposed
5 Depreciation lives.

6 **Q. WHAT ARE THE CURRENT RETIREMENT DATES OF SHERCO UNITS 1 AND**
7 **2 IN NORTH DAKOTA AND HOW WERE THEY DETERMINED?**

8 **A.** The retirement dates for Sherco Units 1 and 2, in 2034, were set as part of a
9 settlement agreement in the Company's 2007 rate case in Case No. PU-07-776
10 and approved by the Commission on December 31, 2008. (Exhibit CJS-1 page 8).
11 The 2034 retirement date was based upon a study completed by Advocacy Staff
12 at the time that determined the average life span of all steam generating plants
13 that had retired between 1900 and 2006 was 59 years. (Exhibit CJS-1 page 8).
14 The Commission has not revised the 2034 retirement date. The 2034 retirement
15 date has been used as the basis of the North Dakota depreciation rates for Sherco
16 Units 1 and 2.

17 **Q. WHAT ARE NSP'S CURRENT RETIREMENT DATES FOR SHERCO UNITS 1**
18 **AND 2 AND HOW WERE THEY DETERMINED?**

19 **A.** NSP's current retirement dates are 2026 for Sherco Unit 1 and 2023 for Sherco
20 Unit 2. NSP decided to retire these Units in 2026 and 2023 during its 2015
21 resource planning cycle on perceived ongoing regulatory risks identified in the
22 Sherco LCM Study.⁹

23 **Q. DID THE NORTH DAKOTA COMMISSION FIND THE EARLY RETIREMENTS**
24 **OF SHERCO UNITS 1 AND 2 TO BE PRUDENT?**

25 **A.** No. The Commission held an informal hearing on the Company's 2015 resource
26 plan on February 11, 2015. On June 3, 2016, Commission Staff advised the
27 Commission that it was premature to retire Sherco Units 1 and 2 in 2026 and 2023,

⁹ The Minnesota Commission approved the remaining lives for Sherco 1 and 2 in MPUC Docket No. E,G002/D-15-46 (Exhibit CJS-1 page 21).

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1 respectively, because of the uncertainties regarding the implementation of the
2 Clean Power Plan and the timing of SCR requirements. (CJS-1 page 21-22).

3 **Q. DID THE COMMISSION AGREE TO TAKE THE 2026 AND 2023 RETIREMENT**
4 **DATES AS THE BASIS FOR NEW DEPRECIATION RATES FOR SHERCO**
5 **UNITS 1 AND 2?**

6 **A.** No. The remaining lives of Sherco 1 and 2 in North Dakota was approved through
7 2034 as part of a settlement agreement in the Company's 2007 rate case (Case
8 No. PU-07-776). As a consequence the North Dakota depreciation rates will not
9 fully recover the costs of Sherco Units 1 and 2 at the dates of their retirements in
10 2026 and 2023, respectively, and there will be a mismatch in the book life of Sherco
11 Units 1 and 2 in North Dakota as compared to the other NSPM jurisdiction. (Exhibit
12 CJS-1 page 8).

13 **Q. IF THE COMMISSION FINDS NSP'S DECISION TO RETIRE SHERCO UNITS 1**
14 **AND 2 IN 2026 AND 2023, RESPECTIVELY TO BE PRUDENT, MUST THE**
15 **COMMISSION ALLOW THE COMPANY TO ADJUST ITS NORTH DAKOTA**
16 **DEPRECIATION RATES ACCORDINGLY?**

17 **A.** No. NSP would recover the depreciation costs of Sherco Units 1 and 2 through
18 2034, for North Dakota ratemaking purposes if the depreciation rates were not
19 adjusted.

20 **Q. WHAT IS YOUR RECOMMENDATION WITH RESPECT TO THE COMPANY'S**
21 **RETIREMENT AND ADJUSTMENTS TO THE COMPANY'S DEPRECIATION**
22 **RELATED TO SHERCO UNITS 1 AND 2?**

23 **A.** I am recommending maintaining the current North Dakota depreciation schedule
24 for Sherco Units 1 and 2 and the removal of the \$3,482,553 from the Company's
25 Depreciation Expense that is related to the retirement of Sherco Units 1 and 2 in
26 2026 and 203, respectively. (Exhibit MPM-1 page 21). (Exhibit BCH-1 Revised
27 Schedule 6). (WP A11 Depreciation Study/Remaining Life).

28

29

1 Q. WHAT OTHER ARGUMENTS ARE YOU RELYING FOR YOUR
2 RECOMMENDATION?

3 A. I note that the North Dakota Commission did not take any action on the Company's
4 Resource Plan. The Commission Staff argued that it was premature to retire
5 Sherco Units 1 and 2 in 2026 and 2023, respectively, because the implementation
6 of the Clean Power Plan was not certain, nor was the timing of SCR requirements.
7 (Exhibit CJS-1 page 21-22). The Commission Staff also stated that the Sherco
8 costs would be stranded costs and no longer used and useful. (CJS-1 page 22).
9 The Company also raises the argument that the Minnesota Commission approved
10 the remaining lives for Sherco Units 1 and 2 consistent with the 2015 Resource
11 Plan and anticipates that the North Dakota Commission should do the same. The
12 Company relies on its decision in 2015 that it was prudent at that time it decided
13 to retire Sherco Units 1 and 2, although there was uncertainty on how regulatory
14 and environmental laws would be enacted, is not a valid argument.¹⁰

15

16 L. Amortization Expense

17 Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS
18 AMORTIZATION EXPENSE?

19 A. The Company has proposed a total Amortization Expense of \$6,231,000 (Exhibit
20 BCH-1 Schedule 6). The breakdown is as follows:

21	a).	Prairie Island EPU Uprate	\$ 308,000
22	b).	Rider RER- PTC	\$4,903,000
23	c).	Income Tax Tracker	\$ 143,000
24	d).	ND RTF Amortization	\$ 187,000
25	e).	NOL ADIT ARAM	\$ 274,000
26	f).	Rate Case Expenses	\$ 419,000
27		Total	\$6,231,000

28

29

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31

¹⁰ Given the Arctic Event occurrence in February 2021, the replacement of certain types of generation/energy should be balanced with reliable resources now and in the future. Alternative generation could be impacted due to extreme change in temperature and weather, and it may not be prudent to have certain types of generation resources in lieu of more traditional generation resources.

1 a). Prairie Island EPU Uprate - \$308,000

2
3 **Q. WHAT IS YOUR RECOMMENDATION WITH RESPECT TO THE COMPANY'S**
4 **PRAIRIE ISLAND EPU UPRATE AMORTIZATION OF \$308,000?**

5
6 **A.** I am recommending removal of the \$308,000 of amortization expenses related to
7 the Company's Prairie Island EPU Uprate. As I removed the plant investment of
8 \$4,109,000 (WP A19). from the Company's EPIS balance, I am removing the
9 associated amortization expense of \$308,000. My adjustment is reflected on
10 Schedule DM-21. The discussion of the project and my arguments for removal is
11 addressed in my testimony under Section A – Electric Plant in Service. The
12 Company was proposing to recover the abandoned plant costs over the remaining
13 life of the plant or 13.33 years. (NDPSC – 5-79).

14
15 b). Renewal Energy Rider (RER) PTC - \$4,903,000

16 **Q. WHAT IS THE COMPANY PROPOSING WITH RESPECT TO ITS RIDER RER**
17 **PTC AMORTIZATION OF \$4,903,000?**

18
19 **A.** The Company has proposed to account for its RER PTC based upon the Levelized
20 Credit Method (LCM). The Company has proposed to reduce the credit from
21 \$7,954,000 to \$5,239,000 as shown on WP-A-21, which will extend the credit over
22 the life of the resource that produces them, (twenty to twenty-five) years, instead
23 of the current ten-year period. (Exhibit BCH-1 page 39 and NDPSC-45). The
24 amortization balance of \$4,903,000 represents LCM liability in this proceeding.

25
26 **Q. WHAT IS YOUR RECOMMENDATION?**

27 **A.** As I indicated previously in my testimony, I am accepting the Company's proposal.
28 However, the Company should confirm that these PTCs do not include the
29 proposed Community Wind and Jeffers Wind North projects which I have
30 recommended be removed from the Company's filing. Based upon the discovery
31 responses (NDPSC-045, and NDPSC 14-1) it is unclear as to how the Company
32 developed its PTCs. My adjustment is shown on Schedule DM-21.

1 c). Income Tax Tracker - \$143,000

2 **Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS INCOME**
3 **TAX TRACKER OF \$143,000?**

4 **A.** The Company is proposing to recover costs associated with tax and interest
5 liabilities related to the North Dakota Retail Jurisdictional share of NSPM
6 operations. The Company is proposing to recover these costs over a three-year
7 period ($\$428,812/3 = \$143,000$). (WP A24 and NDPSC 5-59).

8 **Q. WHAT IS YOUR RECOMMENDATION?**

9 **A.** I am accepting the Company's Income Tax Tracker proposal, and the costs
10 allocated to the North Dakota jurisdiction of \$428,812. I am recommending an
11 amortization period of 3.5 years instead of 3 years. This will allow the Company
12 to recover its Income Tax Tracker costs between normalized rate case
13 proceedings. In determining the 3.5-year period, I relied on the Company's prior
14 rate case applications with the ND Commission which reflected electric rate case
15 filings in 2007, 2010, 2013 and 2020.¹¹ The Company has filed rate case petitions
16 every three-years through 2013 and filed this instant petition at the end of 2020. I
17 normalized the period between rate cases (2007-2021) and arrived at an average
18 3.5-year period between rate cases. This results in an annual recovery of
19 \$122,518. This is shown on Schedule DM-21.

20

21 d). North Dakota RTF Amortization

22 **Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS RESOURCE**
23 **TREATMENT FRAMEWORK (RTF)?**

24

25 **A.** Company witness Mr. Halama stated that the Company is proposing to recover
26 costs of about \$1.8 million of transaction costs associated with preparing the RTF
27 that the Company proposed in Case Nos. PU-12-813, *et. al.* (Exhibit BCH-1 page

¹¹ Public Service Commission, North Dakota (nd.gov)

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1 58). The Company proposed a 10-year amortization period (Exhibit BCH-1 page
2 60). Company witness Mr. Chamberlain (Exhibit GPC-1 Revised) page 28 stated
3 that the RTF was developed to reflect a restacking of resources on the NSP system
4 for purposes of ratemaking in North Dakota. The Company put together a resource
5 treatment framework that would better reflect North Dakota energy policy. (Exhibit
6 GPC-1 page 28). The RTF was proposed to be filed with the Commission by
7 January 1, 2017. (Exhibit BCH-1 page 58). Mr. Chamberlain stated that since
8 2013, the policy misalignment between North Dakota, South Dakota and
9 Minnesota has diminished given much more competitive wind energy prices, such
10 that the RTF may no longer be necessary. (Exhibit GPC-1 page 28).

11 **Q. WHAT HAS CHANGED REGARDING THE POLICY MISALIGNMENT?**

12 **A.** Mr. Halama stated that subsequent to the RTF filing, the Company was entering
13 into a 20-year period in which significant portions of its generating fleet would be
14 retired and replaced. The goal of the RTF was to develop a framework for planning
15 and assigning the costs of new resources as the Company transitioned its fleet.
16 (Exhibit BCH-1 page 58). While the policy differences between North Dakota,
17 South Dakota and Minnesota have somewhat diminished as wind energy prices
18 have decreased, some type of RTF still made sense. Mr. Chamberlain stated that
19 if the 187 MW Solar Portfolio and the MEC II power purchase agreement are not
20 approved by the Commission, it could be appropriate to apply to those resource
21 ratemaking treatments similar to what was contemplated in the Company's RTF
22 filing (NDPSC 5-21). Mr. Chamberlain stated that the RTF was a necessary and
23 valuable exercise, and the Company must manage different state regulatory
24 regimes and policies which can and do materially differ. (NDPSC 5-21).

25 **Q. WHAT IS YOUR RECOMMENDATION?**

26 **A.** I am recommending that the Company not recover RTF amortization costs in rates.
27 The RTF is essentially moot and does not provide any benefits to the ratepayers
28 of North Dakota. In order for costs to be recovered, such costs should be used
29 and useful in the provision of utility service. The Company claims that although
30
31

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1 the RTF may no longer be necessary, it was a necessary and valuable exercise,
2 and the costs incurred were significant, as assistance from consultants and other
3 outside advisors was required. (Exhibit BCH-1 page 59). The Company should
4 not be able to recover costs simply because it was expensive to undertake, it was
5 a necessary and valuable exercise, and it was also complex. The RTF was filed
6 on December 31, 2016; however, the Company is proposing to recover these costs
7 in future rates. Ratemaking principles require costs to be prospective in nature,
8 that match new rates when they are established by the Commission. The
9 proposed RTF amortization recovery appears to be retro-active costs applied to
10 future rates, which should not be allowed. The Company is essentially requesting
11 recovery of costs that have no value to customers. The Company should not be
12 allowed to recover costs merely because the Company paid for it. There is no
13 guarantee that all costs incurred by the Company to be recovered, rather the
14 Company has the opportunity to recover known and measurable and prudent costs
15 in rates. My adjustment is shown on Schedule DM-21.

16
17 e). NOL ADIT ARAM - \$274,000
18

19 **Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS NET**
20 **OPERATING LOSS, ACCUMULATED DEFERRED INCOME TAXES,**
21 **AVERAGE RATE ASSUMPTION METHOD OF \$274,000?**

22 **A.** The Company is proposing to amortize the NOL ADIT ARAM over a 23-year
23 period. The Commission's Order in PU-18-155 approved the Company's proposed
24 amortization level included in the Tax Cuts and Jobs Act (TCJA) refund calculation.
25 (Exhibit BCH-1 page 61). (WP A25).

26 **Q. WHAT ADJUSTMENTS DO YOU HAVE?**

27 **A.** I am accepting the Company's proposal related to the \$274,000 amortization
28 expense related to the NOL ADIT ARAM. My adjustment is shown on Schedule
29 DM-21.

1 f). Rate Case Expenses \$419,000

2 **Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS RATE CASE**
3 **EXPENSES?**

4 **A.** The Company has proposed to recover about \$1.126 million (\$1.126 million / 3
5 three years or \$375,333) of projected direct costs associated with this rate case
6 docket and a three-year amortization period. The Company has included costs
7 associated with a study totaling \$132,000 to be amortized over the same three-
8 year amortization period (\$132,000/3 three years or \$44,000). The total annual
9 amortization amount was \$419,000. (Exhibit BCH-1 page 62). The study relates
10 to a jurisdictional allocation study direct by the Commission in Case No. PU-12-
11 813. The study was to review jurisdictional demand allocation methodologies. The
12 study was completed and provided to the Commission as a Compliance filing in
13 Case No. PU-12-813 on April 27, 2015. The Settlement Agreement provided that
14 the cost of the study should be recovered as a rate case expense in the Company's
15 next electric rate case. (Exhibit BCH-1 page 62).

16 **Q. WHAT IS YOUR RECOMMENDATION?**

17 **A.** I am accepting the Company's proposed rate case expense balance of \$1.258
18 million, including the RTF Study that was directed by the Commission to develop.
19 My only adjustment is to extend the amortization period to 3.5 years consistent
20 with my recommended amortization period for other amortizations in this rate
21 proceeding. My adjustment is shown on Schedule DM-21.

22

23

24

M. Taxes Other Than Income Taxes

25 **Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO TAXES OTHER**
26 **THAN INCOME TAXES?**

27 **A.** As shown on Company Exhibit Revised Schedule 3A page 2 of 4, and in Exhibit
28 BCH-1 Revised Schedule 6, the Company proposed total Taxes other Than

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1 Income Taxes of \$6,093,914.¹² The breakdown representing the balance is as
2 follows:

3	a).	Property Taxes – Net	\$11,495,109
4	b).	Deferred Income Taxes and ITC (Adj.)	(\$ 5,419,000)
5	c).	Precedential /Ratemaking Adjustments	(\$ 2,012,000)
6	d).	Payroll – (Adj.)	<u>\$ 2,032,000</u>
7		Total	\$ 6,096,109
8			

9 a). Property Taxes – Net - \$11,495,109

10 **Q. HOW DID THE COMPANY DEVELOP ITS PROPERTY TAX BALANCE OF**
11 **\$11,495,109?**

12 **A.** The Company began with an Unadjusted Property Tax balance of \$11,602,907
13 (WP P6) and adjusted that balance by (\$66,443) (WP A27) and (\$41,354) (WP
14 A28) for the Rider RER and the Rider TCR, respectively, to arrive at a balance of
15 \$11,495,109.

16 **Q. DO YOU HAVE ANY ADJUSTMENTS TO THE COMPANY PROPERTY TAX**
17 **BALANCE?**

18 **A.** I adjusted the Company's Property Taxes in relation to the Company's EPIS
19 balance. The ratio of the Company's EPIS balance of \$1,471,794,000 to the
20 Property Tax balance (before Rider removals) of \$11,602,907 is 0.00788. My
21 adjusted EPIS Balance includes the removal of the Company's Prairie Island EPU
22 Recovery, the Jeffers/Community Wind North projects and AGIS, of which
23 amounts to a balance of \$1,453,881,818. I then multiplied the ratio of 0.00788 to
24 my recommended balance to arrive at a Property Tax balance of \$11,456,589, or
25 an adjustment of (\$146,318). My recommendation is shown on Schedule DM-22.

26 b). Deferred Income Taxes and ITC (Adj.) (\$5,419,000)

27 **Q. HOW DID THE COMPANY DEVELOP ITS DEFERRED INCOME TAXES AND**
28 **ITS ITC ADJUSTMENT OF (\$5,419,000)?**

¹² Any differences due to rounding.

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1 **A.** The Company began with an Unadjusted Balance of \$8,446,000 (Exhibit BCH-1
2 Revised Schedule 6) and included a Net Operating Loss of (\$13,865,000) to arrive
3 at an Adjusted Balance of (\$5,419,000).

4 **Q.** **WHAT ADJUSTMENTS DO YOU HAVE REGARDING THE COMPANY'S**
5 **DEFERRED INCOME TAXES AND ITC BALANCE?**

6 **A.** I made two adjustments related to the Company's Community Wind North and
7 Jeffers Wind Facilities projects, and the Company's AGIS initiative that I removed
8 under my EPIS balance. Since I removed the associated Accumulated
9 Depreciation, Accumulated Deferred Income Taxes and Depreciation Expense, I
10 am removing the Deferred Taxes for the Community Wind North and Jeffers Wind
11 Facilities of [trade secret data begins] ██████████ [trade secret data ends] as
12 shown on NDPSC 5-76 Attachment B. I am also removing the Deferred Taxes
13 related to the AGIS initiative of \$124,434. Finally, since I made an adjustment to
14 the Company's Depreciable Lives based upon Mr. Garren's recommendation, I am
15 making a corresponding adjustment related to Deferred Income Tax. This
16 computes to an adjustment of (\$106,715). My recommended balance is therefore,
17 (\$6,534,471) as shown on Schedule DM-22.

18 c). Precedential / Ratemaking Adjustments (\$2,012,000)

19
20 **Q.** **WHAT IS INCLUDED IN THE COMPANY'S PRECEDENTIAL AND**
21 **RATEMAKING ADJUSTMENT BALANCE OF (\$2,012,000)?**

22 **A.** As shown on Exhibit BCH-1 Revised Schedule 4, the Company proposed several
23 adjustments related to Precedential Adjustments and the impact on those
24 adjustments equals \$11,000 (Exhibit BCH-1 Revised, Schedule 6 Column 6). The
25 Company also included its Ratemaking adjustments related to: Depreciation Study
26 balance of (\$1,366,000), Non-Plant Excess ADIT balance of \$51,000, PI EPU
27 Uprate Recovery balance of (\$112,000), Rider RER balance of (\$1,940,000), Rider
28 TCR balance of (\$121,000) and a Net Operating Loss balance of \$1,465,000.

29 **Q.** **WHAT ADJUSTMENTS DO YOU HAVE WITH RESPECT TO THE COMPANY'S**
30 **PRECEDENTIAL AND RATEMAKING ADJUSTMENTS?**

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1 **A.** I have three adjustments: (1) Precedential Adjustments – (\$9,347); (2)
2 Depreciation Study adjustment of \$1,101,823; and (3) PI EPU Uprate Recovery of
3 \$112,000.

4 **Q.** **PLEASE EXPLAIN YOUR FIRST ADJUSTMENT OF (\$9,347) RELATED TO**
5 **THE COMPANY’S PRECEDENTIAL ADJUSTMENTS.**

6 **A.** These adjustments reflect my adjustments shown on Schedule DM-19,
7 (Administrative and General Expenses), that relate to Advertising, Association
8 Dues, Aviation, Customer Deposits and Pension Non-Qualified SERP. My
9 explanations for these adjustments are shown under the Administrative and
10 General Expense section of my testimony. I used a ratio of the Company’s total
11 Precedential adjustments of \$1,264,006 to the Precedential Adjustment of \$11,000
12 (Schedule DM-22), to arrive at a ratio of 0.0087. I then took my adjustments and
13 multiplied it by the ratio of 0.0087 to arrive at a balance of \$1,653. This reduces
14 the Company’s Precedential Adjustment balance from \$11,000 by \$9,347 or
15 \$1,653.

16 **Q.** **PLEASE EXPLAIN YOUR SECOND ADJUSTMENT OF \$1,101,823 RELATED**
17 **TO THE DEPRECIATION STUDY.**

18 **A.** Since I made adjustments to the Company’s Depreciation Study, I am reflecting
19 the associated Deferred Income Tax adjustment. I utilized the ratio of the
20 Company’s total Depreciation Study of \$4,860,682 (Schedule DM-20) to the
21 Deferred Adjustment of (\$1,366,000) (Schedule DM-22) to arrive at a ratio of
22 28.10%. I then multiplied my adjusted balance of \$940,131 by 28.10% to arrive
23 at a deferred balance of (\$264,177). The difference is \$1,366,000 minus \$264,177
24 or \$1,101,823.

25 **Q.** **PLEASE EXPLAIN YOUR THIRD ADJUSTMENT OF \$112,000 RELATED TO**
26 **THE PI EPU UPRATE RECOVERY.**

27 **A.** Since I made adjustments to disallow the PI EPU Uprate Recovery in the
28 Company’s EPIS Balance, and other various adjustment to that, I am adjusting the
29 related Deferred Income Tax associated with it. I am removing \$112,000 (WP
30 A19) to arrive at a zero balance. (Schedule DM-22).

1 d). Payroll – (Adj.) \$ 2,032,000

2 **Q. WHAT IS YOUR THIRD ADJUSTMENT \$186,055 RELATED TO PAYROLL AND**
3 **OTHER?**

4 **A.** Since I made adjustments to the Company's Labor balance, and Incentive
5 Compensation I am making the associated adjustment to the Company's Payroll
6 Taxes and Others. I utilized the Company's O&M Labor assigned to the North
7 Dakota jurisdiction (NDPSC 5-054 Attachment B) and the Company's proposed
8 Payroll of \$2,033,000 to arrive at a 7.7035% ratio. I then took my adjustments to
9 Labor and Incentive Compensation and multiplied the balance by 7.7035% to
10 arrive at a Payroll adjustment of \$185,055. I reduced the Company's proposed
11 Payroll Expense by that amount to arrive at my Payroll Expense balance of
12 \$1,847,945. For the Aviation related Payroll, since I removed all Aviation related
13 expenses, I am removing an additional \$1,000 of Payroll Expense (NSPSC 5-41
14 Attachment A). (Exhibit BCH-1 Revised Schedule 6).

15 **Q. WHAT IS YOUR TOTAL ADJUSTMENT RELATED TO THE COMPANY'S**
16 **TAXES OTHER THAN INCOME TAXES?**

17 **A.** My adjustment is a decrease of \$241,165 or a balance of \$5,852,945,425.¹³ This
18 is shown on Schedule DM-22.

19
20

21 **N. State Income Taxes**

22 **Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS STATE**
23 **INCOME TAXES?**

24 **A.** The Company proposed a State Income Tax Expense of \$230,105 (Schedule DM-
25 23).¹⁴

26 **Q. HOW DID THE COMPANY COMPUTE ITS STATE INCOME TAX?**

27 **A.** The Company computed its State Income Taxes by using the Statutory State Tax
28 Rate of 4.31% (Exhibit BCH-1 Revised Schedule 3A), and computed total book

¹³ Differences due to rounding.

¹⁴ Difference due to rounding

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1 income, tax additions and deductions to determine the taxable income that is used
2 to calculate federal and state income taxes (Exhibit BCH-1 page 36). The utilization
3 or generation of net operating losses or tax credits impact both deferred federal
4 income taxes and federal and state income taxes.

5 **Q. HOW DID YOU COMPUTE YOUR STATE INCOME TAXES FOR PURPOSES**
6 **OF THIS PROCEEDING?**

7 **A.** I utilized the Company's methodology, and the flow-throughs of my adjustments to
8 Operating Revenues, Operating Expenses, Depreciation and Amortization
9 Expense, and Rate Base related adjustments, to compute my recommended State
10 Income Tax adjustment.

11 **Q. WHAT IS YOUR STATE INCOME TAX EXPENSE?**

12 **A.** My State Income Tax Expense is \$575,556, an increase of \$345,825 from the
13 Company's proposed State Income Tax Expense of \$229,730. This is shown on
14 Schedule DM-23.

15
16 **O. Federal Income Taxes**

17 **Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS FEDERAL**
18 **INCOME TAXES?**

19 **A.** The Company has proposed a Federal Income Tax Expense of \$1,493,101.¹⁵

20 **Q. HOW DID THE COMPANY COMPUTE ITS FEDERAL INCOME TAX EXPENSE?**

21 **A.** The Company computed its Federal Income Taxes by using the Statutory Federal
22 Tax Rate of 21.00% (Exhibit BCH-1 Revised Schedule 3A) and computed total
23 book income, tax additions and deductions to determine taxable income that is
24 used to calculate federal and state income taxes (Exhibit BCH-1 page 36). The
25 utilization or generation of net operating losses or tax credits impact both deferred
26 federal income taxes and federal and state income taxes.

¹⁵ Differences due to rounding

1 **Q. HOW DID YOU COMPUTE YOUR FEDERAL INCOME TAXES FOR PURPOSES**
2 **OF THIS PROCEEDING?**

3 **A.** As I calculated the Company's State Income Taxes, I have used the same
4 methodology to calculate the Company's Federal Income Taxes, using the same
5 methodology and the flow-throughs of my adjustments to Operating Revenues,
6 Operating Expenses, Depreciation and Amortization Expenses, and Rate Base
7 related adjustments.

8 **Q. WHAT IS YOUR FEDERAL INCOME TAX EXPENSE?**

9 **A.** My Federal Income Tax Expense is \$3,105,826, an increase of \$1,612,643 from
10 the Company's proposed Federal Income Tax Expense of \$1,493,101. This is
11 shown on Schedule DM-24.

12 **Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

13 **A.** Yes, it does. I reserve the right to amend my direct testimony in the event other
14 information becomes forthcoming, subsequent to the filing of this testimony.

15

PCMG and Associates LLC

DANTE MUGRACE

Education

Master Business Administration, MBA Strategic Management, Pace University, Lubin School of Business, New York, NY, 2010

Master Public Administration, MPA, Kean University, Union, NJ, 2001

Bachelor of Science, BS. Accounting, St. Peter's University, Jersey City, NJ, 1983

Position

Senior Consultant – PCMG and Associates	2014 – present
Senior Consultant – Snavelly King Majoros and Associates	2013 – 2014
Independent Consultant	2012 – 2013
Bureau Chief/Administrative Analyst/Accountant – New Jersey Board of Public Utilities	1983 – 2011

Professional Experience

Mr. Mugrace has 35 years' experience in all aspects of regulatory accounting and policy including processing, analyzing and evaluating utility rate case petitions before Public Service Commissions. Mr. Mugrace examines and evaluates rate filings, contracts, agreements and rate matters regarding utility operations and provides recommendations as to best course of action. Additionally, Mr. Mugrace analyzes and reviews utility regulatory matters and sets forth recommendations for resolution of issues, calculates total revenue requirement needed to cover operating expenses and rate of return; researches and evaluates regulatory utility matters to assess impact on various classes of customers, regarding rates, service, compliance and cost of service provisions, as well as annual true-up and tracking mechanisms.

Prior to undertaking consulting assignments, Mr. Mugrace was the Bureau Chief Utility Rate Manager for the New Jersey Board of Public Utilities, in which role he managed and assigned tasks to a staff of 12 professionals and supervisory personal in the daily administrative, financial and managerial functions of the Division. Mr. Mugrace's primary duties were to determine whether the utility had sufficient revenues to cover its operating expenses and earn a return on its plant investment and to ensure that the utility provided safe, reliable and continuing utility service to its customers. Mr. Mugrace set rates and charges for utility companies, which had revenues of up to \$500 million, and ensured that the revenue requirement provided for recovery of all operating expenses, return on investment and depreciation. Mr. Mugrace was also responsible for reviewing and verifying that the companies' property, plant and equipment (up to \$2.5 billion) were used and useful in providing service to its customers. Mr. Mugrace coordinated and met with the New Jersey State Department of Environmental Protection to

PCMG and Associates LLC

determine whether water and wastewater utilities were complying with state regulations and were adhering to any regulatory agency directives or orders. Mr. Mugrace developed ways to minimize the rising costs of water utility services by investigating alternative rate structures, analyzing engineering mechanisms and techniques, looking into the feasibility of mergers and acquisitions within the water industry and reviewing financing, and rate alternatives to minimize the impact on ratepayers. Mr. Mugrace was responsible for ensuring that the rate-case process adhered the statutory timeframe for preparing, reviewing and recommending findings to the Board Commissioners on financial operations, costs, revenues and operating expenses, prior to the litigation proceedings. Mr. Mugrace also examined alternative rate recovery mechanisms and clauses, phase-ins of revenue requirements, deferral mechanisms and pass-through of rate charges. Mr. Mugrace assumed the role of Director during transition periods and Administrative changes. Finally, Mr. Mugrace conducted the recruitment and hiring of employees for placement within the Division and the Board.

Professional and Business Affiliations

- Institute of Public Utilities (IPU) Michigan State University (MSU), National Association of Regulatory Utility Commissioners (NARUC), National Association of State Utility Consumer Advocates (NASUCA)

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PCMG and Associates LLC

Regulatory Projects and Appearances

1. In Re: The Pittsburgh Water and Sewer Authority for approval of increased rates and charges for Water, Wastewater and Stormwater services
(Appearance: Accounting and Policy, and Regulatory Policy) on behalf of the Pennsylvania Office of the Consumer Advocate)
Pennsylvania Public Utility Commission – Docket Nos. R-2021-3024773 (Water) R-2021-3024774 (Wastewater) and R-2021-3024779 (Stormwater).
2. In Re: Northern States Power Company – 2021 Electric Base Rate Case Increase
(Appearance: Revenue Requirement on behalf of the Advocacy Staff of the North Dakota Public Service Commission)
North Dakota Public Service Commission – Case No. PUC-20-441
3. In Re: Public Service Electric and Gas Company – Approval of a Tax Adjustment Clause (TAC).
(Appearance; Revenue Requirement on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket Nos. ER20100685 and GR20100686.
4. In Re: Pike County Light and Power Company – Approval to increase base rates for Electric and Gas Service.
(Appearance: Revenue Requirement in behalf of the Pennsylvania Office of Consumer Advocate)
Pennsylvania Public Utility Commission – Docket Nos. R-2020-3022134 (Gas) and R-2020-3022135 (Electric)
5. In Re: Jersey Central Power and Light Company for Approval of JCP&L’s Energy Efficiency and Conservation Plan Including Energy Efficiency and Peak Demand Reduction Programs.
(Appearance: Revenue Requirement on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket Nos. QO19010040 and EO20090620
6. In Re: Atlantic City Electric Company for Approval of an Energy Efficiency Program, Cost Recovery Mechanism, and Other Related Relief for Plan Years One Through Three.
(Appearance: Revenue Requirement on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket Nos. QO19010040 and EO20090621
7. In Re: Rockland Electric Company for Approval of Its Energy Efficiency and Peak Demand Reduction Programs.
(Appearance: Revenue Requirement on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket Nos. QO19010040 and EO20090623

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8. In Re: Public Service Electric and Gas Company for Approval of Changes in its Electric Green Programs Recovery Charge and its Gas Green Programs Recovery Charge 2020 PSE&G Green Programs Cost Recovery filing
(Appearance: Revenue Requirement on behalf of the NJ Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket Nos. ER20060467 and GR20060468
9. In Re: Public Service Electric and Gas Company's 2020/2021 Annual BGSS Commodity Charge filing for its Residential Gas Customers under its Pricing Mechanism and for Changes in its Balance Charge
(Appearance: Revenue Requirement on behalf of the NJ Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. GR20060379
10. In Re: Public Service Electric and Gas Company's 2020 Annual Margin Adjustment Clause (MAC)
(Appearance: Revenue Requirement on behalf of the NJ Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. GR20060384
11. In Re: South Jersey Gas Company for Approval to Revise the Rider H Rate Associated with the Tax Cuts and Jobs Act of 2017
(Appearance: Revenue Requirement on behalf of the NJ Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. GR20060382
12. In Re: Berkshire Gas Company -2019 Gas System Enhancement Program Reconciliation Filing
(Appearance: Revenue Requirement on behalf of the Massachusetts Office of the Attorney General)
Commonwealth of Massachusetts -Department of Public Utilities – DPU 20-GREC-02
13. In Re: Bay States Gas Company d/b/a Columbia Gas – 2019 Gas System Enhancement Program Reconciliation Filing.
(Appearance: Revenue Requirement on behalf of the Massachusetts Office of the Attorney General)
Commonwealth of Massachusetts – Department of Public Utilities – DPU 20-GREC-05
14. In Re: NSTAR Gas Company – 2019 Gas System Enhancement Program Reconciliation Filing
(Appearance: Revenue Requirement on behalf of the Massachusetts Office of the Attorney General)
Commonwealth of Massachusetts – Department of Public Utilities – DPU 20-GREC-06
15. In Re: South Jersey Gas Company for Approval of Increased Base Tariff Rates and Charges for Gas Service, Changes to Depreciation Rates and Other Tariff Revisions.
(Appearances: Revenue Requirement and Cash Working Capital) on behalf of the New Jersey Division of Rate Counsel.
New Jersey Board of Public Utilities – Docket No. GR20030243

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16. In Re: Jersey Central Power & Light Company for Review and Approval of Increased in, and Other Adjustments to Rates and Charges for Electric Services and approval of Other Proposed Tariff Revisions (Appearance: Revenue Requirement, Cash Working Capital, Consolidated Income Taxes, LED Conversion and Reliability Roll-In) on behalf of the New Jersey Division of Rate Counsel.
New Jersey Board of Public Utilities – Docket No. ER20020146
17. In Re: The Pittsburgh Water and Sewer Authority for approval of increased rates and charges for water and wastewater service and for approval of a multi-year rate plan. (Appearance: Accounting and Policy, Customer Service and Regulatory Policy) on behalf of the Pennsylvania Office of the Consumer Advocate)
Pennsylvania Public Utility Commission – Docket Nos. R-2020-3017951 and R-2020-3017970.
18. In Re: New Jersey-American Water Company, Inc. for approval of Increased Base Tariff Rates and Charges for Water and Wastewater Services and Other Tariff Revisions. (Appearance: Accounting and Revenue Requirement and Cash Working Capital / Consolidated Income Taxes) on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. WR19121516
19. In Re: Hawaiian Electric Company, Inc., for approval of a General Rate Increase and Revised Rate Schedules and Rules.
(Appearance: Accounting and Revenue Requirement on behalf of the Hawaiian Division of Consumer Advocacy)
Hawaii Public Utilities Commission – Docket No. 2019-0085
20. In Re: Mount Olive Villages Water Company for approval of an Increase in Rates for Water Service and Other Tariff Changes.
(Appearance: Accounting and Consulting Services on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. WR19060770
21. In Re: Mount Olive Villages Sewer Company for approval of an Increase in Rates for Sewer Service and Other Tariff Changes.
(Appearance: Accounting and Consulting Services on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. WR19060769
22. In Re: Public Service Electric and Gas Company for approval of changes in its Electric Green Programs Recovery and its Gas Green Programs Recovery Charge (2019 PSE&G Green Programs Cost Recovery Filing).
(Appearance: Accounting and Consulting Services on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket Nos. ER19070764 and GR19070765

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23. In Re: Proposed Amendment to N.J.A.C. 14:9- Adoption by reference to the Uniform System of Accounts for Water Utilities and Wastewater Utilities.
(Appearance: Consulting Services on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities- Docket Nos. WX19050612 (Water) and WX19050613 (Wastewater)
24. In Re: Public Service Electric and Gas Company's 2019/2020 Annual BGSS Commodity Charge filing for its Residential Gas Customers Under its Periodic Pricing Mechanism and for Changes in its Balancing Charge.
(Appearance: Revenue Requirement and accounting/consulting services on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. GR190600699
25. In Re: Bay States Gas Company d/b/a Columbia Gas of Massachusetts for Approval of a 2018 Gas System Enhancement Program Reconciliation Filing
(Appearance: Revenue Requirement on behalf of the Massachusetts Office of the Attorney General)
Commonwealth of Massachusetts Department of Public Utilities – Docket No. 19-GREC-05
26. In Re: NSTAR Gas Company d/b/a Eversource Energy for Approval of a 2018 Gas System Enhancement Program Reconciliation Filing
(Appearance: Revenue Requirement on behalf of the Massachusetts Office of the Attorney General)
Commonwealth of Massachusetts Department of Public Utilities – Docket No. 19-GREC-06
27. In Re: Public Service Electric and Gas Company for Approval of Gas Rate Base Adjustments Pursuant to its Gas System Modernization Program (April 2019 GSMP)
(Appearance: Revenue Requirement on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – Docket No. GR19040522
28. In Re: Kalaeloa Water Company, LLC for Approval of General Rate Case and Revised Rules, Regulations and Rates.
(Appearance: Revenue Requirement on behalf of the Hawaii Division of Consumer Advocacy)
Hawaii Public Utilities Commission – Docket No. 2019-0057
29. In Re: Elizabethtown Gas Company for Approval of an Increase in Rates and Charges for Gas Service, Changes to Depreciation Rates and Other Tariff Revisions.
(Appearance: Revenue Requirement and Other Accounting Issues on behalf of the New Jersey Division of Rate Counsel).
New Jersey Board of Public Utilities – Docket No. GR19040586
30. In Re: Petition of Peoples Natural Gas Company for Approval of an Increase in Rates for Natural Gas Distribution Service.

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(Appearance: Revenue Requirement and Other Accounting Issues on behalf of the Pennsylvania Office of Consumer Advocate)

Pennsylvania Public Utility Commission – Docket No. R-2018-3006818

31. In Re: Petition of Aqua New Jersey, Inc. for Approval of an Increase in Rates for Water Service and other Tariff Changes.
(Appearance: Revenue Requirement and other Accounting Issues on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – BPU Docket No. WR18121351
32. In Re: Petition of Public Service Electric and Gas Company for Approval of its Clean Energy Future – Energy Efficiency (CEF-EE) Program on a Regulated Basis.
(Appearance: Revenue Requirement and other Accounting Issues on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – BPU Docket Nos. GO18101112 and EO18101113.
33. In Re: Petition of Public Service Electric and Gas Company for Approval of its Clean Energy Future – Energy Vehicle and Energy Storage (CEF-EVES) Program on a Regulated Basis. (Appearance – Revenue Requirement and other Accounting Issues on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – BPU Docket No. EO18101111.
34. In Re: Petition of New Jersey Natural Gas Company- Request for Deferred Accounting Authority for Costs Related to New Information Technology Systems . (Appearance: Impact on Revenues, prudence of costs on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – BPU Docket No. GR18101096
35. In Re: Petition for Approval of An Indirect Change in Control of the New Jersey Public Utilities Subsidiaries of SUEZ Water Resources, Inc. and Other Related Approvals.
(Appearance: Impact on Rates, Service, Employees, Positive Benefits on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – BPU Docket No. WM18090982
36. In Re: The Matter of the Merger of Roxbury Water Company into New Jersey American Water Company (Appearance: Impact on Rates, Service and Employees, Positive Benefits on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities – BPU Docket No. WM18080904
37. In Re: The Matter of the Application of Maryland-American Water Company for Authorization to Adjust its Existing Schedule of Tariffs and Rates.
(Appearance: Revenue Requirement on behalf of the Maryland Office of People’s Counsel)
Maryland Public Service Commission – Case No. 9487

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38. In Re: The Matter of the Joint Petition for Approval of an Increase in Rates for Water and Wastewater Service and Other Tariff Changes for SUEZ Water NJ, Inc., Toms River, Inc., Arlington Hill, Inc., West Milford, Inc., Matchaponix, Inc., and Princeton Meadows, Inc. (Appearance: Revenue Requirement and the development of Consolidated Income Taxes on behalf of the NJ Division of Rate Counsel)
New Jersey Board of Public Utilities – BPU Docket No. WR18050593
39. In Re: The Matter of the Application of Atlantic City Electric Company to Adjust the Level of its Rider RGGI Rate Associated with its Solar Renewable Energy Certificate Financing Program 2018 (Appearance: Revenue Requirement on behalf of the NJ Division of Rate Counsel)
New Jersey Board of Public Utilities – BPU Docket No. ER18050543
40. In Re: The Matter of the Petition of New Jersey Natural Gas Company’s Approval of the Cost Recovery Associated with Energy Efficiency Programs (Appearance; Revenue Requirement on behalf of the NJ Division of Rate Counsel)
New Jersey Board of Public Utilities – BPU Docket No, GR18050585
41. In Re: The Matter of Bay States Gas Company d/b/a Columbia Gas of Massachusetts, 2017 Gas System Enhancement Reconciliation Filing (Appearance: Revenue Requirement on behalf of the Massachusetts Attorney General’s Office of Ratepayer Advocacy)
Commonwealth of Massachusetts – Department of Public Utilities – Docket No. D.P.U. 18-GREC-05.
42. In Re; The Matter of NSTAR Gas Company d/b/a Eversource Energy, Gas System Enhancement Program Reconciliation Filing (Appearance: Revenue Requirement on behalf of the Massachusetts Attorney General’s Office of Ratepayer Advocacy)
Commonwealth of Massachusetts – Department of Public Utilities – Docket No. D.P.U. 18-GREC-06.
43. In Re: The Matter of the Merger of SUEZ Water NJ, SUEZ Water Toms River, SUEZ Water Arlington Hills, SUEZ Water West Milford, SUEZ Water Princeton Meadows and SUEZ Water Matchaponix (Appearance: Positive Benefits related to the Merger on behalf of the NJ Division of Rate Counsel)
New Jersey Board of Public Utilities – BPU Docket No. WR18030266
44. In Re: The Matter of the Columbia Gas of Pennsylvania for a General Rate Increase in Distribution Gas Service (Appearance; Accounting Issues and Revenue Requirement on behalf of the Pennsylvania Office of Consumer Advocate)
Pennsylvania Public Utility Commission – Docket No. R-2018-2647577
45. In Re: The Matter of the New Jersey Board of Public Utilities Consideration of the Tax Cuts and Jobs Act of 2017 – Generic Proceeding (Appearance: Revenue Requirement on behalf of the NJ Division of Rate Counsel)
New Jersey Board of Public Utilities – BPU Docket No. AX18010001

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46. In Re: Acquisition of Elizabethtown Gas, a Division of Pivotal Utilities Holdings, Inc. by ETG Acquisition Corp., a Division of South Jersey Industries, Inc., and Related Transactions. (Appearance: Customer Service Issues/Employee and Labor Relations on behalf of the NJ Division of Rate Counsel)
New Jersey Board of Public Utilities – BPU Docket No. GM17121309.
47. In Re: Middlesex Water Company – Base Rate Case Proceeding for Water Service. (Appearance: revenue requirement on behalf of the NJ Division of Rate Counsel).
New Jersey Board of Public Utilities – BPU Docket No. WR17101049.
48. In Re: Township of East Brunswick – Sewer Rate Study – (Evaluation of the existing sewer rate structure and examining and quantify costs for future expansion).
49. In Re: Montana-Dakota Utilities – Base Rate Case Proceeding for Gas Service. (Appearance: revenue requirement on behalf of the North Dakota Public Service Commission). NDPSC Docket No. PU-17-295.
50. In Re: Andover Utility Company – Base Rate Case Proceeding for Wastewater Services. (Appearance: revenue requirement on behalf of the New Jersey Division of Rate Counsel).
New Jersey Board of Public Utilities – BPU Docket No. WR17070726.
51. In Re: Public Service Electric and Gas Company- Approval of Changes in its Electric and Gas Green Programs Recovery Charges “2017 Public Service Electric & Gas Green Programs Cost Recovery Filing. (Appearance: revenue requirement on behalf of the New Jersey Division of Rate Counsel).
New Jersey Board of Public Utilities – BPU Docket Nos. ER17070724 and GR17070725.
52. In Re: Bay States Gas Company d/b/a Columbia Gas of Massachusetts, 2016 Gas System Enhancement Program Reconciliation Filing, (Appearance: revenue requirement on behalf of the Massachusetts Attorney General’s Office of Ratepayer Advocacy).
Commonwealth of Massachusetts Department of Public Utilities – Docket No. D.P.U. 17-GREC-05.
53. In Re; NSTAR Gas Company d/b/a Eversource Energy, 2016 Gas System Enhancement Program Reconciliation Filing (Appearance: revenue requirement on behalf of the Massachusetts Attorney General’s Office of Ratepayer Advocacy).
Commonwealth of Massachusetts Department of Public Utilities – Docket No. D.P.U. 17-GREC-06.
54. In Re: Petition of Columbia Gas of Maryland – Increase in rates for Distribution Service – (Appearance: revenue requirement on behalf of the Office of People’s Counsel) Public Service Commission of Maryland – Case No. 9447
55. In Re: Petition of South Jersey Gas Company – Increase in base rates for gas services – (Appearance: revenue requirement on behalf of the NJ Division of Rate Counsel)

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New Jersey Board of Public Utilities – Docket No. GR17010071

56. In Re: Petition of UGI Penn Natural Gas – Increase in base rates for gas services – (Appearance: revenue requirement on behalf of the Pennsylvania Office of Consumer Advocate)
Pennsylvania Public Utilities Commission Docket No. R-2016-2580030
57. In Re: Petition of PJM Interconnection, LLC. – Mid-Atlantic Interstate Transmission, LLC. Formula Rate Filing. (Appearance on behalf of the Pennsylvania Office of Consumer Advocate).
FERC Docket No. ER17-211-000
58. In Re: Petition of Pivotal Utility Holdings, Inc. d/b/a Elizabethtown Gas Company for approval of Increased Base Tariff Rates and Charges for Gas Service and Other Tariff Revisions (Appearance: revenue requirement on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities Docket No. GR16090826
59. In Re: Petition of SUEZ Water New Jersey, et al – Approval of a Management and Services Agreement pursuant to N.J.S.A 48: 3-7.1 (Appearance on the reasonableness of contract agreements on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities Docket No. WO16080806
60. In Re: Petition of SUEZ Water Arlington Hills Inc. – Approval of an Increase in Rates for Wastewater Services and other Tariff Changes (Appearance: revenue requirement on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities Docket No. WR16050510
61. In Re: Petition of Public Service Electric and Gas Company – 2016 Marginal Adjustment Clause (MAC) (Appearance; reconciliation and rate setting on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities Docket No. GR16060484
62. In Re: Petition of Public Service Electric and Gas Company for Approval of Changes in its Electric Green Programs Recovery Charges and its Gas Green Program Recovery Charges 2016 PSEG Program Cost Recovery Filing (Appearance: reconciliation and rate setting on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities Docket Nos. ER16070613 and GR16070614
63. In Re: Petition of the Mount Olive Village Sewer Company, Inc., for Approval of an Increase in Rates for Service (Appearance: revenue requirement on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities Docket No. WR16050391

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64. In Re: Petition of the Mount Olive Village Water Company, Inc. for Approval of an Increase in Rates for Service (Appearance; revenue requirement on behalf of the New Jersey Division of Rate Counsel)
New Jersey Board of Public Utilities Docket No. WR16050390
65. In Re: Petition of Fitchburg Gas and Electric Light Company d/b/a Unitil for Approval of its 2015 Gas System Enhancement Plan Reconciliation Filing (2016) - (Analysis and Advice to Counsel: computation of the revenue requirement and rate impact on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
MA Department of Public Utilities Docket No. D.P.U. 16-GREC-01
66. In Re: Petition of Bay State Gas Company d/b/a Columbia Gas of Massachusetts for Approval of its 2015 Gas System Enhancement Plan Reconciliation Filing (2016) - (Appearance: computation of the revenue requirement and rate impact on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
MA Department of Public Utilities Docket No. D.P.U. 16-GREC-05
67. In Re: Petition for Approval of Gas Infrastructure Contract Between Public Service Company of New Hampshire d/b/a Eversource Energy and Algonquin Gas Transmission, LLC (2016) - (Analysis and Advice to Counsel: compliance with statutes and regulations, review of contract, and ratemaking on behalf of the New Hampshire Office of Consumer Advocate)
NH Public Utilities Commission Docket No. DE 16-241
68. In Re: Central Maine Power Company, Annual Compliance Filing and Price Change (2016) - (Analysis and Advice to Counsel; tax normalization regulatory asset on behalf of the Maine Office of the Public Advocate)
ME Public Service Commission Docket No. 2016-00035
69. In Re: Bulletin 2015-10 Generic Proceeding to Establish Parameters for the Next Generation PBR Plans (Appearance: productivity adjustments/performance-based ratemaking on behalf of the Alberta Utilities Consumer Advocate)
Alberta Utilities Commission Proceeding 20414
70. In Re: the Matter of Request by Emera Maine for Approval of a Rate Change (2016) - (Appearance: revenue requirement on behalf of the Maine Office of the Public Advocate)
Maine Public Utilities Commission Docket No. 15-00360)
71. In Re: the Matter of the Joint Application of the Southern Company, AGL Resources Inc., and Pivotal Holdings, Inc. d/b/a Elkton Gas (2015-2016) - (Analysis and advice to counsel: customer service impacts, employee impacts, supplier diversity on behalf of the Maryland Office of People's Counsel)
MD PSC Case No. 9404

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72. In Re: the Matter of the Merger of Southern Company and AGL Inc. (2015-2016) - (Appearance: customer service impacts and employee impacts on behalf of the NJ Division of Rate Counsel)
New Jersey BPU Docket No. GM15101196
73. In Re: the Matter of the United Water New Jersey, Inc., for Approval of an Increase in Rates for Water Service and Other Tariff Changes (2015-2016) - (Appearance: revenue requirements, rate base issues and operating income on behalf of the NJ Division of Rate Counsel)
New Jersey BPU Docket No. WR15101177
74. In Re: Petition of Boston Gas Company and Colonial Gas Company d/b/a National Grid for Approval of Precedent Agreements with Millennium Pipeline Company, LLC (2015) - (Analysis: review of contract and compliance of the Gas Supply Plan on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
MA D.P.U. 15-130
75. In Re: Petition of Boston Gas Company and Colonial Gas Company d/b/a National Grid for Approval of Agreements for LNG or Liquefaction Services with GDF Suez Gas NA, LLC; Northeast Energy Center, LLC; Metro LNG, L.P.; and National Grid LNG (2015) - (Analysis: review of contract and compliance of the Gas Supply Plan on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
MA D.P.U. 15-129
76. In Re: Columbia Gas of Massachusetts CY2014 Targeted Infrastructure Reinvestment Factor (TIRF) Compliance Filing (2015) - (Appearance: computation of the revenue requirement impact on the TIRF on behalf of the Massachusetts Attorney General Office of Ratepayer Advocacy)
MA D.P.U. 15-55
77. In Re: the Matter of the Bay State Gas Company d/b/a Columbia Gas of Massachusetts for Approval of its Targeted Infrastructure Reinvestment Factor (TIRF) for CY 2013 (2014) - (Appearance: computation of the revenue requirement impact on the TIRF)
MA D.P.U. 14-83
78. In Re: the Matter of the Merger of Exelon Corporation and Pepco Holdings, Inc. (Atlantic City Electric Company) (2014-2015) - (Appearance: customer service impacts)
New Jersey BPU Docket No. EM14060581
79. In Re: of the Public Utilities Commission of Ohio, in the Matter of the Application of Aqua Ohio, Inc. to Increase its Rates and Charges for its Waterworks Service. – Revenue and Rates (2014) - (Appearance: operating income, certain rate base issues and income taxes on behalf of the Ohio Office of Consumer Counsel)
PUCO Case No. 13-2124-WW-AIR

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80. In Re: New York Public Service Commission, as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. Revenue Requirement (2013-2014) – (Appearance: revenue requirement, rate base issues and operating income on behalf of the Intervenor, the County of Westchester)
NYPSC Case Nos. 13-E-0030, 13-G-0031 and 13-S-0032, et al
81. In Re: North Dakota Public Service Commission, - Application of Northern States Power Company for Authority to Increase Rates for Electric Service in North Dakota, On-Going Revenue Requirement (2013) - (Appearance: revenue requirement and rate base, operating income, operating and maintenance expenses on behalf of the North Dakota Public Service Commission Staff)
North Dakota Case No. PU-12-813
82. In the Matter of the Petition of New Jersey American Water Company for Authorization to Implement a Distribution System Improvement Charge (DSIC) Order Denying Petition and Instituting Stakeholder Process (2008) - (Case manager on policy decision and revenue requirement impact on behalf of the Staff of the NJ Board of Public Utilities)
BPU Docket No. WO08050358
83. In the Matter of the Joint Petition of the City of Trenton, New Jersey and New Jersey-American Water Company, Inc. for Authorization of the Purchase and Sale of the Assets of the Outside Water Utility System ("OWUS") of the City of Trenton, New Jersey and for Other Relief Order Adopting Initial Decision, (2008) - (Case manager on the revenue requirement impact on behalf of the Staff of the NJ Board of Public Utilities)
BPU Docket No. WM08010063
84. In the Matter of the Petition of United Water New Jersey, United Water Toms River, United Water Lambertville, United Water Mid-Atlantic and Gaz de France for Approval as Need for a Change in Ownership and Control (2007) - (Case manager on customer impact, employee impact and impact on rates on behalf of the Staff of the NJ Board of Public Utilities)
BPU Docket No. WM06110767
85. In the Matter of the Petition of United Water Arlington Hills Sewerage, Inc. for an Increase in Rates for Waste Water Service and Other Tariff Changes (2009) - (Case manager on revenue requirement and overall rate proceeding on behalf of the Staff of the NJ Board of Public Utilities)
BPU Docket No. WR08100929
86. In the Matter of the Petition of United Water New Jersey Inc. for Approval of an Increase in Rates for Water Service and Other Tariff Changes, (2009) - (Case manager on revenue requirement and overall rate proceeding on behalf of the Staff of the NJ Board of Public Utilities)
BPU Docket No. WR08090710

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87. In the Matter of the Petition of United Water Toms River, Inc. for Approval of an Increase in Rates for Water Service and Other Tariff Changes (2008) - (Case manager on the revenue requirement and overall rate proceeding on behalf of the Staff of the NJ Board of Public Utilities)
BPU Docket No. WR08030139
88. In the Matter of the Joint Petitioners of New Jersey-American Water Company, Inc., S.J. Services, Inc., South Jersey Water Company, Inc. and Pennsgrove Water Supply Company, Inc. for Among Other Things Approval of a Change in Control of South Jersey Water Supply Company, Inc. and Pennsgrove Water Supply Company, Inc. (2007) - (Case manager on the overall rate proceeding on behalf of the Staff of the NJ Board of Public Utilities)
BPU Docket No. WM07020076
89. In the Matter of the Petition of Aqua, New Jersey, Inc. for Approval of an Increase in Rates for Water Service and Other Tariff Changes (2008) - (Case manager on revenue requirement and the overall rate proceeding on behalf of the Staff of the NJ Board of Public Utilities)
BPU Docket No. WR0712095
90. I/M/O the Joint Petition of Thames Water, Aqua Holdings GMBH, on Behalf of Itself and Its Parent Holdings Company, RWE Aktiengesellschaft, Thames Water Aqua US Holdings, Inc., American Water works Company Inc., Thames Water Holdings Incorporated, E'town Corporation, New Jersey-American Water Company, Inc., Elizabethtown Water Company, the Mount Holly Water Company and Applied Wastewater Management, Inc. for Confirmation that the Board of Public Utilities Does Not Have Jurisdiction Over, or, Alternatively, for Approval of a Proposed Transaction Involving, Among Other Things, the Sale by Thames Water Aqua Holdings GMBH of Up to 100% of the Shares of the Common Stock of American Waterworks Company, Inc. in One or More Public Offerings (2007) - (Case manager on revenue requirement impacts, effect on rates and effect on service on behalf of the Staff of the NJ Board of Public Utilities)
BPU Docket No. WM06050388
91. In the Matter of the Petition of Elizabethtown Water Company for Approval of an Increase in Rates for Water Service (2007) - (Case manager on revenue requirement and overall rate proceeding on behalf of the Staff of the NJ Board of Public Utilities)
BPU Docket No. WR03070510
92. In the Matter of the Petition of New Jersey American Water Company, Inc. for Approval of Increased Tariff Rates and Charges for Water and Sewer Service; Increased Depreciation Rates and Other Tariff Revisions (2008) - (Case manager on revenue requirement and overall rate proceeding on behalf of the Staff of the NJ Board of Public Utilities)
BPU Docket No. WR08010020
93. In the Matter of Middlesex Water Company for Approval of an Increase in its Rates for Water Service and Other Tariff Changes (2007) - (Case manager on overall revenue

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requirement and overall rate proceeding on behalf of the Staff of the NJ Board of Public Utilities)

BPU Docket No. WR07040275

94. In the Matter of the Joint Petition of United Water New Jersey, Inc., United Water Arlington Hills, Inc., United Water Hampton, Inc., United Water Vernon Water Hills, Inc., and United Water Lambertville, Inc. for an Increase in Rates and Charges for Water Service and Other Tariff Changes and for Approval to Merge the Operations of the Joint Petitioners into and with United Water New Jersey, Inc. (2007) - (Case manager on revenue requirement and overall rate proceeding on behalf of the Staff of the NJ Board of Public Utilities)

BPU Docket No. WR07020135

REVENUE REQUIREMENT

	(1) Company Proposed	Adjustments	ND PSC Advocacy Staff	References
1 Average Rate Base	\$ 676,916,000	\$ (18,467,137)	\$ 658,448,863	
2 Operating Income	\$ 35,241,366	\$ 6,933,935	\$ 42,175,301	
3 AFUDC	\$ -		\$ -	
4 Total Available for Return	\$ 35,241,366	\$ 6,933,935	\$ 42,175,301	
5 Overall Rate of Return	5.206%		6.405%	
6 Required Return	7.350%		6.818%	
7 Operating Income Requirement	\$ 49,753,326	\$ (4,863,575)	\$ 44,889,751	
8 Income Deficiency	\$ 14,511,960	\$ (11,797,510)	\$ 2,714,450	
9 Gross Revenue Requirement Factor	1.322837		1.322837	(2)
10 Revenue Deficiency	\$ 19,196,958	\$ (15,606,182)	\$ 3,590,775	
11 Revenues at Present Rates	\$ 206,416,272	\$ -	\$ 206,416,272	
12 Percentage Increase	9.300%		1.740%	
(1) Company Exhibit BCH-1 Revised Sch. 7				
(2) Company Exhibit BCH-1 Revised Sch. 3A				
State Income Tax	4.310000%			
Federal Income Tax	21.000000%			
Effective Tax Rate	20.090000%			
Composite Tax Rate	24.400000%			
Revenue Requirement Factor	1.322751			

Differences due to rounding

**WEIGHTED AVERAGE
COST OF CAPITAL**

(1) Company Proposed	Ratios	Cost of Capital	Weighted Average
1 LT Debt	46.9600%	4.2189%	1.9812%
2 ST Debt	0.5400%	1.0000%	0.0100%
3 Common Equity	52.5000%	10.2000%	5.3550%
4 Total Capital	100.0000%		7.3500%

(2) ND PSC Advocacy Staff

5 LT Debt	50.0000%	4.2200%	2.1100%
6 ST Debt	0.5000%	1.0000%	0.0050%
7 Common Equity	49.5000%	9.5000%	4.7025%
8 Total Capital	100.0000%		6.8175%

- (1) Company Workpaper C1
- (2) Exhibit MFG-20 Schedule 3

AVERAGE RATE BASE

	(1)		ND PSC	References	
	Company Proposed	Adjustments	Advocacy Staff		
<u>Electric Plant In Service</u>					
1	Production Plant	\$ 885,937,000	\$ -	\$ 885,937,000	
2	Transmission Plant	\$ 240,321,000	\$ -	\$ 240,321,000	
3	Distribution Plant	\$ 213,025,000	\$ (13,482,182)	\$ 199,542,818	
4	General Plant	\$ 72,035,000	\$ -	\$ 72,035,000	
5	Common Plant	\$ 60,477,000	\$ (4,430,000)	\$ 56,047,000	
6	Total Electric Plant In Service	\$ 1,471,795,000	\$ (17,912,182)	\$ 1,453,882,818	DM-5
<u>Reserve for Depreciation</u>					
7	Production Plant	\$ 471,529,000	\$ (1,742,277)	\$ 469,786,723	
8	Transmission Plant	\$ 60,624,000	\$ (1,000)	\$ 60,623,000	
9	Distribution Plant	\$ 80,327,000	\$ (447,411)	\$ 79,879,589	
10	General Plant	\$ 36,969,000	\$ 1,000	\$ 36,970,000	
11	Common Plant	\$ 28,392,000	\$ (444,000)	\$ 27,948,000	
12	Total Reserve for Depreciation	\$ 677,841,000	\$ (2,633,688)	\$ 675,207,312	DM-6
<u>Net Utility Plant In Service</u>					
13	Production Plant	\$ 414,408,000	\$ 1,742,277	\$ 416,150,277	
14	Transmission Plant	\$ 179,697,000	\$ 1,000	\$ 179,698,000	
15	Distribution Plant	\$ 132,698,000	\$ (13,034,771)	\$ 119,663,229	
16	General Plant	\$ 35,066,000	\$ (1,000)	\$ 35,065,000	
17	Common Plant	\$ 32,085,000	\$ (3,986,000)	\$ 28,099,000	
18	Net Electric Utility Plant In Service	\$ 793,954,000	\$ (15,278,494)	\$ 778,675,506	
19	Electric Utility Plant Held for Future Use	\$ -	\$ -	\$ -	
20	Constuction Work in Progress	\$ 1,914,000	\$ -	\$ 1,914,000	NDPSC 5-35
21	Accumulated Deferred Income Taxes	\$ (147,086,000)	\$ 2,347,601	\$ (144,739,399)	DM-7
22	Cash Working Capital	\$ (7,103,000)	\$ 841,200	\$ (6,261,800)	DM-8
23	Sub-Total	\$ 641,679,000	\$ (12,090,693)	\$ 629,588,307	
<u>Other Rate Base Items</u>					
24	Materials and Supplies	\$ 10,807,000	\$ -	\$ 10,806,596	DM-9
25	Fuel Inventory	\$ 6,579,000	\$ -	\$ 6,579,039	DM-9
26	Non-Plant Assets/Liabilities	\$ 8,415,000	\$ (2,062,000)	\$ 6,353,000	DM-9
27	Customer Advances	\$ (62,000)	\$ -	\$ (62,381)	DM-9
28	Customer Deposits	\$ (71,000)	\$ (274)	\$ (71,274)	DM-9
29	Prepays and Others	\$ 5,160,000	\$ -	\$ 5,159,576	DM-9
30	Regulatory Amortizations	\$ 4,409,000	\$ (4,313,000)	\$ 96,000	DM-9
31	Total Other Rate Base Items	\$ 35,237,000	\$ (6,376,444)	\$ 28,860,556	
32	Total Average Rate Base	\$ 676,916,000	\$ (18,467,137)	\$ 658,448,863	

(1) Company Exhibit BCH-1 Revised Sch. 15

OPERATING INCOME STATEMENT

	(1)				Present Rates		
	Company Proposed Present Rates	Rate Adjustments	Company Proposed Final Rates	Adjustments	ND PSC Advocacy Staff	References	
<u>Operating Revenues</u>							
1	Retail Revenues	\$ 206,416,272	\$ 19,197,034	\$ 225,613,306		\$ 206,416,272	
2	Interdepartmental Revenues	\$ -	\$ -	\$ -			
3	Other Operating Revenues	\$ 39,560,473	\$ -	\$ 39,560,473	\$ (338,094)	\$ 39,222,379	
4	Total Operating Revenues	\$ 245,976,745	\$ 19,197,034	\$ 265,173,779	\$ (19,535,128)	\$ 245,638,651	
<u>Operating Expenses</u>							
5	Fuel & Purchased Energy	\$ 53,350,866	\$ -	\$ 53,350,866	\$ (340,887)	\$ 53,009,979	DM-12
6	Power Production	\$ 46,186,043	\$ -	\$ 46,186,043	\$ (1,999,182)	\$ 44,186,861	DM-13
7	Transmission	\$ 17,568,994	\$ -	\$ 17,568,994	\$ (730,344)	\$ 16,838,650	DM-14
8	Distribution	\$ 8,529,179	\$ -	\$ 8,529,179	\$ (3,232,236)	\$ 5,296,943	DM-15
9	Customer Accounting	\$ 4,008,156	\$ -	\$ 4,008,156	\$ (634,416)	\$ 3,373,740	DM-16
10	Customer Service & Info.	\$ 284,060	\$ -	\$ 284,060	\$ 31,244	\$ 315,304	DM-17
11	Sales Econ Develop & Other	\$ 118,859	\$ -	\$ 118,859	\$ (102,859)	\$ 16,000	DM-18
12	Admin. & General	\$ 16,782,031	\$ -	\$ 16,782,031	\$ (1,373,707)	\$ 15,408,324	DM-19
13	Total Operating Expenses	\$ 146,828,188	\$ -	\$ 146,828,188	\$ (8,382,386)	\$ 138,445,802	(2)
14	Depreciation Expense	\$ 54,543,818	\$ -	\$ 54,543,818	\$ (4,719,372)	\$ 49,824,446	DM-20
15	Amortization Expense	\$ 6,231,557	\$ -	\$ 6,231,557	\$ (572,578)	\$ 5,658,979	DM-21
16	Taxes Other Than Income	\$ 6,093,914	\$ -	\$ 6,093,914	\$ (241,172)	\$ 5,852,742	DM-22
17	State Income Taxes	\$ (597,661)	\$ 827,391	\$ 229,730	\$ 345,826	\$ 575,556	DM-23
18	Federal Income Taxes	\$ (2,364,428)	\$ 3,857,607	\$ 1,493,179	\$ 1,612,647	\$ 3,105,826	DM-24
19	Total Operating Expenses	\$ 210,735,388	\$ 4,684,998	\$ 215,420,386	\$ (11,957,035)	\$ 203,463,351	
20	AFUDC	\$ -	\$ -	\$ -			
21	Total Operating Income	\$ 35,241,357	\$ 14,512,036	\$ 49,753,393	\$ (7,578,092)	\$ 42,175,301	
22	Rate Base	\$ 676,916,000		\$ 676,916,000	\$ (18,467,137)	\$ 658,448,863	
23	Rate of Return	5.21%		7.35%		6.82%	

- (1) Company Exhibit BCH-1 RevisedSchedule 3A
 Company Exhibit BCH-1 RevisedSchedule 11
 (2) Any differences due to rounding

SCHEDULE DM-5

PU-20-441

CONFIDENTIAL-FILED AS TRADE SECRET

SCHEDULE DM-6

PU-20-441

CONFIDENTIAL-FILED AS TRADE SECRET

SCHEDULE DM-7

PU-20-441

CONFIDENTIAL-FILED AS TRADE SECRET

CASH WORKING CAPITAL

		(1)			ND PSC		
		Company Proposed			Advocacy Staff		References
	Lead/Lag Days	Dollars	Dollar x Days	Adjustments			
<u>Fuel Expense</u>							
1	Coal/Rail Transport	19.130	\$ 10,225,000	\$ 195,604,250	\$ -	\$ 195,604,250	
2	Gas for Generation	39.340	\$ 9,087,000	\$ 357,482,580	\$ -	\$ 357,482,580	
3	Oil	11.500	\$ 1,000	\$ 11,500	\$ -	\$ 11,500	
4	Nuclear and EOL	0.000	\$ 7,779,000	\$ -	\$ -	\$ -	
5	Nuclear Disposal	0.000	\$ -	\$ -	\$ -	\$ -	
6	Total Fuel Expense		\$ 27,092,000	\$ 553,098,330	\$ -	\$ 553,098,330	
<u>Purchased Power</u>							
7	Purchases	39.690	\$ 33,163,000	\$ 1,316,239,470	\$ -	\$ 1,316,239,470	
8	Interchange	37.290	\$ 11,514,000	\$ 429,357,060	\$ -	\$ 429,357,060	
9	Total Purchased Power		\$ 44,677,000	\$ 1,745,596,530	\$ -	\$ 1,745,596,530	
<u>Labor & Related</u>							
10	Regular Payroll	11.900	\$ 26,917,000	\$ 320,312,300	\$ (28,586,426)	\$ 291,725,874	
11	Incentive	248.780	\$ 1,007,000	\$ 250,521,460	\$ (86,260,733)	\$ 164,260,727	
12	Pension & Benefits	37.290	\$ 4,998,000	\$ 186,375,420	\$ -	\$ 186,375,420	
13	Total Labor & Payroll		\$ 32,922,000	\$ 757,209,180	\$ (114,847,159)	\$ 642,362,021	
14	All Other Operating Expenses	39.250	\$ 49,271,000	\$ 1,933,886,750	\$ (238,431,164)	\$ 1,695,455,586	
15	Property Taxes	356.830	\$ 11,603,000	\$ 4,140,298,490	\$ (52,243,935)	\$ 4,088,054,555	
16	Employer's Payroll Taxes	30.140	\$ 2,032,000	\$ 61,244,480	\$ (5,607,700)	\$ 55,636,780	
17	Gross Earnings Tax	41.130	\$ 3,829,000	\$ 157,486,770	\$ -	\$ 157,486,770	
18	Federal Income Taxes	37.500	\$ (3,842,000)	\$ (144,075,000)	\$ 27,606,450	\$ (116,468,550)	
19	State Income Taxes	37.500	\$ (824,000)	\$ (30,900,000)	\$ 9,316,650	\$ (21,583,350)	
20	State Sales Tax Customer Billings	0.000	\$ -	\$ -	\$ -	\$ -	
21	Sub-Total		\$ 62,069,000	\$ 6,117,941,490	\$ (259,359,699)	\$ 5,858,581,791	
22	Total Expenses		\$ 166,760,000	\$ 9,173,845,530	\$ (374,206,858)	\$ 8,799,638,672	
23	Net Annual Expense		55.012	\$ 25,134,000	\$ (1,022,990)	\$ 24,111,010	
<u>Revenues</u>							
24	Retail Revenues	40.550	\$ 208,952,000	\$ 8,473,003,600	\$ (102,823,770)	\$ 8,370,179,830	
25	Late Payment	0.000	\$ 436,000	\$ -	\$ -	\$ -	
26	Misc. Services	40.550	\$ 448,000	\$ 18,166,400	\$ -	\$ 18,166,400	
27	Rentals	(100.200)	\$ 334,000	\$ (33,466,800)	\$ (1,062,320)	\$ (34,529,120)	NDPSC 5-38
28	Interchange	37.290	\$ 29,551,000	\$ 1,101,956,790	\$ -	\$ 1,101,956,790	
29	Sales for Resale	34.060	\$ 522,000	\$ 17,779,320	\$ -	\$ 17,779,320	
30	Retail Rev. Lag Days	40.550	\$ 84,000	\$ 3,406,200	\$ -	\$ 3,406,200	
31	MISO	14.000	\$ 424,000	\$ 5,936,000	\$ -	\$ 5,936,000	
32	Wholesale Lag Days	34.060	\$ 15,512,000	\$ 528,338,720	\$ -	\$ 528,338,720	
33	Total Revenues		\$ 256,263,000	\$ 10,115,120,230	\$ (103,886,091)	\$ 10,011,234,139	
34	Net Annual Amount		39.472	\$ 27,713,000	\$ (282,218)	\$ 27,430,782	
35	Expense/Revenue Factor			65.07%		65.07%	
36	Allocated Amount			\$ 18,033,894		\$ 17,849,210	
37	Net CWC			\$ (7,100,106)	\$ 838,305	\$ (6,261,800)	

(1) Company Exhibit BCH-1 Schedule 8

OTHER RATE BASE ITEMS

	(1) Company Proposed	Adjustments	ND PSC Advocacy Staff	References
1 Materials and Supplies - Total	\$ 174,923,376	\$ -	\$ 174,923,376	WP P5-2
2 North Dakota Allocation	6.178%		6.178%	
3 North Dakota Amount	\$ 10,806,596	\$ -	\$ 10,806,596	
4 Fuel Inventory - Total	\$ 97,123,363	\$ -	\$ 97,123,363	
5 North Dakota Allocation	6.774%		6.774%	
6 North Dakota Amount	\$ 6,579,039	\$ -	\$ 6,579,039	
7 Non-Plant Assets/Liabilities - Total	\$ 88,306,992	\$ (2,128,992)	\$ 86,178,000	WP P1-3
8 North Dakota Allocation	9.529%		7.372%	
9 North Dakota Amount	\$ 8,415,116	\$ (2,062,116)	\$ 6,353,000	
10 Customer Advances - Total	\$ (9,169,912)		\$ (9,169,912)	WP P9-2
11 North Dakota Allocation	0.680%		0.680%	
12 North Dakota Amount	\$ (62,381)		\$ (62,381)	
13 Customer Deposits - Total	\$ (44,930,376)	\$ -	\$ (44,930,376)	WP P9
14 North Dakota Allocation	0.159%		0.159%	
15 North Dakota Amount	\$ (71,274)	\$ -	\$ (71,274)	
16 Prepaid and Others - Total	\$ 80,616,733	\$ -	\$ 80,616,733	NDPSC 5-037
17 North Dakota Allocation	6.400%		6.400%	
18 North Dakota Amount	\$ 5,159,576	\$ -	\$ 5,159,576	
<u>Regulatory Amortizations</u>				
19 Electric Income Tax Tracker - ND	\$ 357,000	\$ (357,000)	\$ -	NDPSC 5-37
20 PI EPU Deferral - ND	\$ 3,955,000	\$ (3,955,000)	\$ -	NDPSC 5-37
21 NOL Tax Reform ADIT ARAM- Total	\$ 52,566,000			NDPSC 14-1
22 North Dakota Allocation	10.149%			
23 North Dakota Amount	\$ 5,335,000	\$ -	\$ 5,335,000	NDPSC 5-37
24 RER PTC Amortization - ND	\$ (5,239,000)	\$ -	\$ (5,239,000)	NDPSC 5-37/45
25 Total North Dakota Amount				WP-A21
26 (Lines 19, 20, 23, 24)	\$ 4,408,000	\$ (4,312,000)	\$ 96,000	
27 Total Other Rate Base Items	\$ 35,234,672	\$ (6,374,116)	\$ 28,860,556	

(1) Company P1-1 Summary TY 2021
Company Exhibit BCH-1 Revised Schedule 3A

OPERATING REVENUES

	(1) Company		Company		Present Rates	References
	Present Rates	Adjustments	Proposed	Adjustments	ND PSC Advocacy Staff	
<u>Electric Retail Revenues</u>						
1	Energy Revenues	\$ 142,422,014				
2	Fuel Revenues	\$ 43,826,382				
3	RER Rider	\$ (2,671,439)				WP-A27
4	TCR Rider	\$ 136,191				WP-A28
5	Rider Revenues	\$ 22,702,687				
6	Total	\$ 206,416,272	\$ 19,197,034	\$ 225,613,306	\$ -	\$ 206,416,272
<u>Other Operating Revenues</u>						
7	Connect Smart	\$ 2,896	\$ -	\$ 2,896	\$ 2,896	
8	Electric Revenue - Other	\$ 1,863,345	\$ -	\$ 1,863,345	\$ 310,297	\$ 2,173,642
9	Operating Revenue- Interchange	\$ 29,440,013	\$ -	\$ 29,440,013	\$ -	\$ 29,440,013
10	Trading Revenue	\$ 23,346,510	\$ -	\$ 23,346,510	\$ -	\$ 23,346,510
11	Transmission Revenue	\$ 15,372,532	\$ -	\$ 15,372,532	\$ -	\$ 15,372,532
12	PI EPU Interchange	\$ (39,334)	\$ -	\$ (39,334)	\$ -	\$ (39,334)
13	Interchange Decommissioning	\$ (582,671)	\$ -	\$ (582,671)	\$ -	\$ (582,671)
14	Sub-Total - Unadjusted	\$ 69,403,291	\$ -	\$ 69,403,291	\$ 310,297	\$ 69,713,588
<u>Precedential Adjustments</u>						
15	Asset Trading - Revenue	\$ (10,716,813)	\$ -	\$ (10,716,813)	\$ -	\$ (10,716,813)
16	Non-Asset Trading - Revenue	\$ (12,107,430)	\$ -	\$ (12,107,430)	\$ -	\$ (12,107,430)
17	Depreciation Study Production	\$ 648,391	\$ -	\$ 648,391	\$ (648,391)	\$ -
18	Depreciation Study - TD&G	\$ 84,531	\$ -	\$ 84,531	\$ -	\$ 84,531
19	TCR Rider	\$ (7,751,497)	\$ -	\$ (7,751,497)	\$ -	\$ (7,751,497)
20	Sub-Total	\$ (29,842,818)	\$ -	\$ (29,842,818)	\$ (648,391)	\$ (30,491,209)
21	Total Other Electric Revenues	\$ 39,560,473	\$ -	\$ 39,560,473	\$ (338,094)	\$ 39,222,379
22	Total Company Present Rates	\$ 245,976,745	\$ 19,197,034	\$ 265,173,779	\$ (338,094)	\$ 245,638,651

(1) Company WP - R6 Back-Up
 Company WP R5 Other Revenue

Operating & Maintenance Expenses
Workpaper

Three-Year Normalize

	(1)				
	Company			ND PSC	
	Proposed	Adjustments		Advocacy Staff	References
1 Fuel & Purchased Energy	\$ 53,350,866	\$ -	\$ -	\$ 53,350,866	NSPSC 5-40
<u>Power Production</u>					
2 Fixed	\$ 31,066,266	\$ -	\$ -	\$ 31,066,266	
<u>Fixed IA Investment</u>					
3 Fixed IA O&M	\$ 3,042,842	\$ -	\$ -	\$ 3,042,842	
4 Variable	\$ 510,248	\$ (24,584)	\$ -	\$ 485,664	DM-13
5 Variable IA O&M	\$ 1,053,581	\$ -	\$ -	\$ 1,053,581	
6 Purchased Demand	\$ 9,827,919	\$ -	\$ -	\$ 9,827,919	
7 Regional Markets	\$ 685,188	\$ (31,479)	\$ -	\$ 653,709	DM-13
8 Transmission IA	\$ 7,417,449	\$ -	\$ -	\$ 7,417,449	
9 Transmission	\$ 10,151,545	\$ (605,930)	\$ -	\$ 9,545,615	DM-14
10 Distribution	\$ 8,529,179	\$ (1,426,175)	\$ -	\$ 7,103,004	DM-15
11 Customer Accounting	\$ 4,008,156	\$ (516,414)	\$ -	\$ 3,491,742	DM-16
12 Customer Service / Information	\$ 284,060	\$ 31,304	\$ -	\$ 315,364	DM-17
13 Sales, Economic Develop / Other	\$ 118,859	\$ -	\$ -	\$ 118,859	DM-18
14 Administrative/General	\$ 16,782,031	\$ (908,384)	\$ -	\$ 15,873,647	DM-19
15 Total	\$ 146,828,189	\$ (3,481,661)	\$ -	\$ 143,346,528	

(1) Exhibit BCH-1 Revised Schedule 3A

SCHEDULE DM-12

PU-20-441

CONFIDENTIAL-FILED AS TRADE SECRET

SCHEDULE DM-13

PU-20-441

CONFIDENTIAL-FILED AS TRADE SECRET

TRANSMISSION EXPENSES

	(1) Company Proposed	Adjustments	ND PSC Advocacy Staff	References
1 Unadjusted Balance	\$ 24,420,000		\$ 23,814,070	NDPSC 5-40
2 Transmission	\$ -	\$ (605,930)		DM-11
3 Labor Adjustment	\$ -	\$ (124,420)	\$ (124,420)	NDPSC 5-20/54
Rider - Transmission Cost Recovery				
4 Rider (TCR)	\$ (6,851,000)	\$ -	\$ (6,851,000)	WP-A28 '5-40
5 Adjusted Balance	\$ 17,569,000	\$ (730,350)	\$ 16,838,650	

(1) Exhibit BCH-1 Revised Schedule 6

DISTRIBUTION EXPENSES

	(1) Company Proposed	Adjustments	ND PSC Advocacy Staff	References
1 Unadjusted Balance	\$ 8,529,000		\$ 6,076,943	NDPSC 5-040
2 ECustMNNND Border	\$ -	\$ (1,426,175)	\$ (1,426,175)	DM-11 - (2)
3 Labor Adjustment	\$ -	\$ (1,025,882)	\$ (1,025,882)	NDPSC 5-20/54
4 AGIS - FAN	\$ -	\$ (80,000)	\$ (80,000)	5-73
5 AGIS - AMI	\$ -	\$ (150,000)	\$ (150,000)	5-73
6 AGIS - ADMS	\$ -	\$ (210,000)	\$ (210,000)	5-73
7 AGIS - Other	\$ -	\$ (340,000)	\$ (340,000)	5-73
8 Adjustments - Other	\$ -			
9 Adjusted Balance	\$ 8,529,000	\$ (3,232,057)	\$ 5,296,943	

- (1) Exhibit BCH-1 Revised Schedule 6
 Exhibit KAB-1 page 28-32
 (2) NDPSC 14-2

CUSTOMER ACCOUNTING EXPENSE

	(1) Company Proposed	Adjustments	ND PSC Advocacy Staff	References
1 Unadjusted Balance	\$ 4,008,000		\$ 3,491,586	
2 EBadDebt		\$ (516,414)		DM-11 - (2)
3 Labor Adjustment	\$ -	\$ (17,846)	\$ (17,846)	NDPSC 5-20/54
	\$ -	\$ -		
4 AGIS - AMI	\$ -	\$ (100,000)	\$ (100,000)	5-73
5 AGIS-Other				5-74
6 Adjustments - Other	\$ -		\$ -	
7 Adjusted Balance	\$ 4,008,000	\$ (634,260)	\$ 3,373,740	5-40

(1) Company Exhibit BCH-1 Revised Schedule 6

(2) NDPSC 14-2

**CUSTOMER SERVICE &
 INFORMATION EXPENSE**

	(1) Company Proposed	Adjustments	ND PSC Advocacy Staff	References
1 Unadjusted Balance	\$ 284,000		\$ 315,304	
2 Adjustments	\$ -	\$ 31,304	\$ -	DM-11
3 Adjusted Balance	<u>\$ 284,000</u>	<u>\$ 31,304</u>	<u>\$ 315,304</u>	5-40

(1) Exhibit BCH-1 Revised Schedule 6

**SALES, ECONOMIC DEVELOPMENT
 AND OTHER EXPENSES**

	(1) Company Proposed	Adjustments	ND PSC Advocacy Staff	References
1 Unadjusted Balance	\$ 16,000	\$ -	\$ 16,000	
2 Economic Develop Donations	\$ 103,000	\$ (103,000)	\$ -	WP A13 5-29/51
3 Adjusted Balance	\$ 119,000	\$ (103,000)	\$ 16,000	

(1) Exhibit BCH-1 Revised Schedule 6

**ADMINISTRATIVE & GENERAL
 EXPENSES**

	(1)		ND PSC	
	Company	Adjustments	Advocacy Staff	References
	Proposed			
1 Unadjusted Balance	\$ 17,885,000		\$ 16,976,616	
2 ECustMNND Border	\$ -	\$ (216,327)		DM-11 - (2)
3 EDemandProd	\$ -	\$ (229,574)		DM-11 - (4)
4 EDirectND	\$ -	\$ 241,780		DM-11 - (4)
5 TwoFactorAlloc	\$ -	\$ (704,263)		DM-11 - (4)
6 Labor Adjustment	\$ -	\$ (770,060)	\$ (770,060)	NDPSC 5-20/54
<u>Precedential Adjustments</u>				
7 NSPM - Advertising	\$ (237,734)	\$ (36,780)	\$ (274,514)	WP A1 - (2)
8 NSPM - Association Dues	\$ (21,599)	\$ (14,216)	\$ (35,815)	WP A2/5-50
9 NSPM - Aviation	\$ (99,354)	\$ (99,354)	\$ (198,708)	WP- A3 - 5-24
10 NSPM - Customer Deposits	\$ 2,814	\$ (1,196)	\$ 1,618	WP A4
11 NSPM - Employee Expenses	\$ (81,941)	\$ 658,432	\$ 576,491	WP A5/12-2
12 NSPM - Pension Non-Qualified SERP	\$ (17,186)	\$ 138,123	\$ 120,937	WP A6/12-2
13 Sub- Total	\$ (455,000)	\$ 645,009	\$ 190,009	
14 Dues - Chamber of Commerce	\$ 20,000	\$ (20,000)	\$ -	WP A20 5-56
15 Foundation and Other Donations	\$ 68,000	\$ (68,000)	\$ -	WP A14 5-52
16 Incentive Compensation	\$ (736,000)	\$ (252,241)	\$ (988,241)	WP-A15-18 - (3)
17 Adjusted Balance	\$ 16,782,000	\$ (1,373,676)	\$ 15,408,324	

- (1) Exhibit BCH-1 Revised Schedule 4 and 6
- (2) NDPSC DR 5-50
- (3) NDPSC 12-7
- (4) NDPSC 14-2

SCHEDULE DM-20

PU-20-441

CONFIDENTIAL-FILED AS TRADE SECRET

AMORTIZATION EXPENSE

	(1)		ND PSC	
	Company	Adjustments	Advocacy Staff	References
	Proposed			
1 Unadjusted Balance	\$ -			
2 Prairie Island EPU Uprate	\$ 308,000	\$ (308,000)	\$ -	WP-A19 NDPSC 5-79
3 Rider RER - PTC	\$ 4,903,000	\$ -	\$ 4,903,000	NDPSC-5-45
4 Income Tax Tracker	\$ 143,000	\$ (20,482)	\$ 122,518	NDPSC-5-59
5 ND RTF Amortization	\$ 184,000	\$ (184,000)	\$ -	WP-A-23 5-21
6 NOL ADIT ARAM	\$ 274,000	\$ -	\$ 274,000	NDPSC-5-60
7 Rate Case Expenses	\$ 419,000	\$ (59,538)	\$ 359,462	WP-A26
8 Adjusted Balance	\$ 6,231,000	\$ (572,021)	\$ 5,658,979	

(1) Exhibit BCH-1 Revised Schedule 6

SCHEDULE DM-22

PU-20-441

CONFIDENTIAL-FILED AS TRADE SECRET

SCHEDULE DM-23

PU-20-441

CONFIDENTIAL-FILED AS TRADE SECRET

SCHEDULE DM-24

PU-20-441

CONFIDENTIAL-FILED AS TRADE SECRET