

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 – North Dakota
20 (NSPC or Company) gas base rate case proceeding that was filed with the North
21 Dakota Public Service Commission (NDPSC or Commission) on September 1,
22 2021 in Case No. PU-21-381. My overall revenue requirement recommendations
23 are based upon the Company’s proposed test year period ending December 31,
24 2022. The Company has proposed an annual revenue requirement increase of
25 \$7,059,000 or 10.50% over current rate revenues. Incorporated into my testimony,
26 I have presented findings with respect to the Company’s test year rate base,
27 revenues, operating expenses and net income at present rate revenues. I have
28 incorporated and am relying on the recommendations of Dr. Marlon Griffing for

1 cost of capital and return on equity, and Dr. Karl Pavlovic for cost of service and
2 rate design that may affect my revenue 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 NSPC'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-23.

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

11 **A.** As previously indicated above, the Company filed an application for an increase in
12 electric service on September 1, 2021, requesting an increase in base distribution
13 rates in the amount of \$7,059,000 or 10.50% above current rates. The revenue
14 requirement is predicated upon a future test year ending December 31, 2022,
15 (Exhibit BCH-1 Schedule 11) which include an overall rate of return of 7.45% and
16 a common equity component of 10.50%. (Exhibit BCH-1 Schedule 3A). The
17 Company has computed an average rate base balance of \$124,227,000 based
18 upon average balances of plant investments. The Company is proposing to
19 include certain costs related to the Settlement Agreement approved by the
20 Commission in Case No. PU-18-156 related to the expense of amortized Fargo
21 manufactured gas plant (MGP) remediation costs of \$1.25 million. The Company's
22 last base rate case was approved in 2007 by the Commission in Case No. PU-06-
23 525.

24 **Q. HOW DID THE COMPANY COMPUTE ITS PROPOSED REVENUE**
25 **REQUIREMENT INCREASE OF \$7,059,000.**

26 **A.** The Company has computed its proposed revenue requirement increase by
27 computing the average rate base (beginning and ending test year balances) and
28 the adding and subtracting average balances related to Cash Working Capital
29 (CWC) materials and supplies, fuel inventory, prepayments and various non-plant

1 assets and liabilities. The Company multiplied its proposed average rate base
2 balance of \$124,227,000 by the proposed rate of return of 7.45% to arrive at a
3 proposed Operating Income requirement of \$9,255,000. The Company then
4 subtracted its Operating Income at present rates of \$3,919,000 to arrive at an
5 income deficiency of \$5,336,000.¹ The Company then multiplied this amount by its
6 revenue conversion factor of 1.32284 to arrive at its revenue requirement increase
7 proposal of \$7,059,000.

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

10 **A.** Yes.

11 **Q. HAS THE COMPANY UPDATED ITS PROPOSED REVENUE REQUIREMENT**
12 **INCREASE SUBSEQUENT TO THE SEPTEMBER 1, 2021 FILING DATE?**

13 **A.** No.

14 **Q. WHAT HAS THE COMPANY EXPERIENCED REGARDING THE EFFECT OF**
15 **THE COVID-19 PANDEMIC ON ITS PROPOSED RATE REQUEST?**

16 **A.** Company witness Mr. Adam Dietenberger in response to data request 1-10 stated
17 that the Company has experienced higher uncollectible accounts expenses in the
18 period during the COVID-19 pandemic when compared to pre-pandemic period.
19 The uncollectible accounts is recognized as a combination of estimating an amount
20 of outstanding accounts receivables that will be unrecoverable and writing off
21 uncollectible accounts not previously reflected in this provision. Mr. Dietenberger
22 stated that as part of the Settlement Agreement in the Company's 2020 electric
23 rate increase in Case No. PU-20-441, the Company agreed to withdraw its
24 requested deferral of COVID-19 related costs, including bad debt and not recover
25 such costs from its North Dakota customers. This withdrawal relates to both
26 electric and gas businesses, for any future electric or gas rate case.

27 **Q. WHAT HAS THE COMPANY EXPERIENCED WITH RESPECT TO ITS DAY-TO-**
28 **DAY OPERATIONS?**

¹ Company Exhibit BCH-1 Schedule 7 page 1.

1 **A.** Ms. Zich stated that gas emergency response was not affected and that employees
2 still responded to calls to ensure public and community safety was not
3 compromised. (NDPSC 1-11). The Company was able to prioritize work to
4 minimized contact with the public. Large capital projects were also executed
5 accordingly.

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

7 **A.** Based upon the use of the Company's test year period ending December 31, 2021,
8 I have the following recommendations:²

- 9 1. My recommended rate base balance is \$122,531,000 which is \$1,695,900
10 lower than the Company's proposed rate base balance of \$124,227,000.
- 11 2. My rate of return is based upon the recommendation of Dr. Marlon Griffing
12 which recommends an overall return of 6.86%, which includes a common
13 equity component of 9.43%.
- 14 3. My recommended operating revenues at present rates is \$67,853,000 which is
15 the same as the Company's operating revenues at present rates of
16 \$67,853,000.
- 17 4. My overall revenue requirement increase based upon an overall rate of return
18 of 6.86% is \$2,990,332 or 4.443%; this is \$4,068,225 lower than the Company's
19 overall revenue requirement increase of \$7,059,000 or 10.48%.

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

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

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

26 **A.** Yes. I am accepting certain of the Company's Rate Base balances and certain of
27 the Company's Operating Income adjustments. These adjustments are not
28 identified in my testimony but are identified in my revenue requirement schedules.

² Differences due to rounding

1 My testimony reflects the areas of disagreement from that of the Company and the
2 affect these adjustments have on rates.

3 4 **III. Cost of Capital**

5 **Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS COST OF**
6 **CAPITAL?**

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

11 **Q. WHAT IS YOUR RECOMMENDED COST OF CAPITAL?**

12 **A.** As per Advocacy Staff witness Dr. Griffing's recommendation, I am incorporating
13 an overall cost of capital of 6.86% which includes a common equity component of
14 9.43%. This is shown on Schedule DM-2, and on Dr. Griffing's Exhibit MFG-16,
15 Schedule 3.

16 17 **REVENUE REQUIREMENT ISSUES**

18 **IV. Rate Base Issues**

19 **A. Gas Plant in Service (GPIS)**

20 **Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS GAS PLANT**
21 **IN SERVICE BALANCE?**

22 **A.** As shown on Exhibit BCH-1 Schedule 3A the Company proposed an average plant
23 in service balance of \$222,855,000, as of December 31, 2022. The Company has
24 developed this balance starting with total Company investments proposed in the
25 2021 test year period and allocating investments to the North Dakota jurisdiction.
26 The Company calculated the investment related to the North Dakota jurisdiction by
27 the use of a simple average of projected net plant at the beginning and end of the

1 test year consistent with the method employed in the Company's most recent North
2 Dakota gas rate case (Exhibit BCH-1 page 17). The Company has included costs
3 related to the Fargo Capacity Project that was placed in service on October 13,
4 2021 ((Data Request 1-49). The need for this Project was explained by the
5 Company is Ms. Zich testimony (Exhibit JHZ-1) page 20. The Company stated
6 that there may be restoration work in the spring of 2022. The total cost of the Fargo
7 Capacity Project was estimated at \$27.5 million (Exhibit JHZ-1 page 24) and was
8 operational during the winter of 2021-2022. The Company also included Peaking
9 Plant Investment costs related to the Westcott LNG peaking plant, the Sibley
10 Propane Air facility and the Maplewood Propane Air facility. (Exhibit JLZ-1 page
11 30). The Company stated that that these types of investments are needed to
12 enhance reliability and maintain compliance with state and federal codes. Ms. Zich
13 stated that the Company has made capital investments in these types of plants
14 since the last base rate case proceeding in 2007. (Exhibit JLZ-1 page 31). Ms. Zich
15 stated that these plant investments include significant refurbishment and
16 replacement of the existing infrastructure in all three facilities to prepare them for
17 continued operations for years to come and this work is occurring in the 2021-2022
18 timeframe. (Exhibit JLZ-1 page 32).

19 **Q. WHAT OTHER INVESTMENTS HAS THE COMPANY INCLUDED IN ITS TEST**
20 **YEAR PERIOD?**

21 **A.** The Company has included costs related to the Inside Meter Move Out Program
22 where the Company will move most of its gas meters still located inside of
23 customer premises to outside locations and replace existing facilities with new
24 meters, connections and regulators. (Exhibit JLZ-1 page 16). This project is
25 required by federal code and allows the Company to more efficiently perform
26 routine required inspections and maintenance of these meter without having to
27 coordinate access or inconvenience to customers. (Exhibit JLZ-1 page 16). The
28 Company is expected to replace over 550 meters outside over a five-year period
29 beginning with 100 meters to be moved in 2022. (Exhibit JLZ-1 page 16). The
30 average cost to move a meter to the outside is about \$3,500 (Data Response 1-
31 46). The Company is proposing to institute a Modular Replacement Program that

1 will address the replacement of current automaking meter reading (AMR)
2 technology, as the Company's current agreement with its meter reading provider
3 will expire in December 2025, and the current technology will no longer be
4 supported (Exhibit JLZ-1 page 17). The new modules will be owned by the
5 Company and the meter reading will be performed by the Company. The program
6 will begin in 2022 and conclude in 2025. (Exhibit JLZ-1 page 17).

7 **Q. HOW DID THE COMPANY DEVELOP THE PLANT BALANCES FOR THE END**
8 **OF THE TEST YEAR PERIOD 2022?**

9 **A.** The Company stated that the 2021 ending plant balances were determined by the
10 Company's actual net investments (Plant in Service less Accumulated
11 Depreciation) on the books and records of the Company as of January 31, 2021.
12 The Company budgeted projections for February through December 2021 and
13 applied those projections to the January 31, 2021 balance to arrive at a beginning
14 test year net plant balance. (Exhibit BCH-1 page 17). The ending net plant
15 balances were determined by applying the data contained in the 2022 capital
16 budget to the balance at December 31, 2021 adjusted for plant additions,
17 retirements, depreciation, salvage and removal costs projected to occur during the
18 test year. The result is a simple average or projected plant at the beginning and
19 ending 2022 test year.

20 **Q. HOW DOES THE COMPANY ALLOCATE ITS GAS PLANT IN SERVICE**
21 **BALANCE FROM THAT OF THE PARENT COMPANY – XCEL ENERGY AND**
22 **NORTHERN STATES POWER COMPANY – MINNESOTA (NSPM)?**

23 **A.** The Company allocates its Gas Plant in Service (GPIS) balance by the use of
24 jurisdiction allocations from NSPM (total utility) to the North Dakota jurisdiction.
25 The jurisdiction cost of service study allocates rate base, capital structure, cost of
26 capital, income taxes and cash working capital from NSPM to the North Dakota
27 jurisdiction (Exhibit BCH-1 page 13). The jurisdiction cost of service schedules for
28 the 2022 test year is shown on Company Schedule 3A (Exhibit BCH-1 page 13).
29 The Operating Income Jurisdiction is shown on Company Exhibit BCH-1 Schedule
30 13 (11.2872% allocation factor) and the Rate Base Jurisdiction is shown on
31 Company Exhibit BCH-1 Schedule 14 (11.2872% allocation factor).

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

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

Q. DO YOU HAVE ANY ADJUSTMENTS WITH RESPECT TO THE COMPANY'S GPIS BALANCE OF \$222,855,000?

A. Yes. My first adjustment is related to the Company's inclusion of applying a 2% escalation factor related to the average meter installation costs of \$388,500. (\$3,500 per meter relocation installation costs times 111, the number of meters expected to be placed outside). I removed the 2% escalation factor or \$7,617 (\$388,500 / 1.02% minus \$380,882 or \$7,617), because I believe an escalation factor does not provide true costs of an item, as these types of costs only provide blanket increase of goods and services that may or may not reflect the costs incurred by the Company. My second adjustment is related to the Company's Fargo Capacity Plant Project. This Project included \$600,000 of contingency reserves (Data Response 4-9). The Company stated that the contingency reserve is for unknowns and not quantified by individual risk items but is used to cover items not already identified. In response to Data Request 4-7 the Company stated that it does not anticipate any restoration costs in 2022. Therefore, this contingency costs should be removed from the Company's Fargo Capacity Plant Project.

Q. HAS THE COMPANY INCLUDED COSTS TO SUPPORT THE ADVANCED GRID INTELLIGENCE AND SECURITY (AGIS) INITIATIVE?

A. In Exhibit LJW-1 page 20, the Company proposed a new subaccount under FERC Account 397 for smart grid assets used to support the AGIS initiative. The Company has proposed a 10-year average service life with zero net salvage. In response to Data Request 1-62 the Company stated that it will update the costs for removing this project and calculate an update revenue requirement.

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

2 **A.** I am recommending removal of approximately \$608,000 from the Company's GPIS
3 balance shown on my Schedule DM-5. As I testified to above, inflation
4 adjustments should not be included in the development of the revenue requirement
5 as these types of costs do not reflect the costs that have actually been incurred by
6 the Company. I am also removing \$600,000 related to a contingency reserve
7 related to the Fargo Capacity Plant Project as these costs are unknown and not
8 quantified.

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10 **B. Accumulated Depreciation**

11 **Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ACCUMULATED**
12 **DEPRECIATION?**

13 **A.** In the same manner as the Company developed its GPIS balance, the Company
14 performed the same analysis with respect to its Accumulated Depreciation or
15 Depreciation Reserve amount, by taking the simple average of balances at the
16 beginning and end of test year. The Company proposed an average depreciation
17 reserve balance of \$82,973,000 as shown on Company Exhibit BCH-1 Schedule
18 3A.

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

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

23 **Q. WHAT SPECIFIC ADJUSTMENTS DO YOU HAVE REGARDING YOUR**
24 **ADJUSTMENTS TO THE COMPANY'S GPIS BALANCE?**

25 **A.** As I removed approximately \$608,000 from the Company's UPIS additions related
26 to the meter installation project and the contingency costs related to the Fargo
27 Capacity Plant Project, I am removing the associated Accumulated Depreciation
28 of \$16,078 (computations addressed under Depreciation Expense in Section K).
29 My adjustment is shown on my Schedule DM-6.

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C. Accumulated Deferred Income Taxes (ADIT)

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

A. The Company has proposed an ADIT balance of \$19,782,000 as shown on Exhibit BCH-1 Revised Schedule 15. The Company used an average projected ADIT balance of projected beginning and ending 2022 test year ADIT balances and incorporates IRS tax regulations. (Exhibit BCH-1 page 19). With respect to the TCJA of 2017, the Commission adopted a Settlement in Case No.PU-18-156 that required the Company to amortize its excess plant – related ADIT using the Average Rate Assumption Method (ARAM) and amortize unprotected, excess non-plant related ADIT over a three-year period. Consistent with this requirement, the Company amortized the excess plant related ADIT using ARAM and the excess non-plant related ADIT was amortized over a three-year period ending in 2020, therefore no impact remains in the 2022 test year. (Exhibit BCH-1 page 20).

Q. DO YOU HAVE ANY ADJUSTMENTS REGARDING THE COMPANY’S METHODOLOGY ON THE DEVELOPMENT OF ITS ADIT?

A. No. I am accepting the Company’s methodology as to the development of the Company’s ADIT.

Q. WHAT SPECIFIC ADJUSTMENTS DO YOU HAVE REGARDING YOUR ADJUSTMENTS TO THE COMPANY’S GPIS BALANCE?

A. My adjustments reflect the flow through of my adjustments related to the Fargo Capacity Plant Project and the adjustment related to the inflation adjustment for the meter installation project and applying a 21% income tax rate to arrive at a balance of \$3,376. My adjustment is shown on my Schedule DM-7.

D. Cash Working Capital (CWC)

1 **Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO CASH**
2 **WORKING CAPITAL (CWC)?**

3 **A.** The Company has proposed a CWC balance of \$648,000 as shown on Exhibit
4 BCH-1 Revised Schedule 3A. The Company has included certain investments,
5 various non-plant assets and liabilities. (Exhibit BCH-1 page 29). For certain
6 components, the Company has used thirteen-month average balances projected
7 during the test year. For other components, the Company has used a simple
8 average of beginning and ending test year balances. The Company has calculated
9 its CWC by applying the results of a comprehensive lead/lag study to the projected
10 test year revenues and expenses. (Exhibit BCH-1 page 30-31).

11 **Q. DO YOU HAVE ANY ADJUSTMENTS IN THE WAY THE COMPANY HAS**
12 **COMPUTED ITS CWC BALANCE?**

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

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

17 **A.** In response to Data Response 4-3, the Company stated that it inadvertently
18 included in the All Other Operating Expenses fuel expenses. The Company stated
19 that correcting this placement in the CWC calculation reduces the Company's
20 revenue requirement by \$122,000. The Company calculated an CWC of
21 (\$673,000) and has stated that it will update its filing in its rebuttal testimony.
22 Based upon this response, I have adjusted my CWC accordingly and based upon
23 my adjustments to the Company's Rate Base components, the Operating Income
24 and the Operating Expenses, I have calculated a CWC balance of (\$438,738).
25 This is shown on Schedule DM-8.

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29 **E. Other Rate Base Items**

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

3 **A.** The Company proposed other Rate Base Item of \$3,292,000 as shown on Exhibit
4 BCH-1 Schedule 3A (\$3,940,000 less Cash Working Capital of \$648,000).

5 **Q. DO YOU HAVE ANY ADJUSTMENTS RELATED TO THE COMPANY'S**
6 **PROPOSED OTHER RATE BASE ITEMS?**

7 **A.** Yes. I have one adjustment related to the Company's Regulatory Amortization for
8 its proposed Income Tax Tracker (WP A15).

9 (1) Gas Income Tax Tracker – ND \$27,951 (Company shows
10 \$22,547).
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13 **Q. WHAT DOES THIS BALANCE REPRESENT?**

14 **A.** (1) The Gas Income Tax Tracker – Mr. Halama stated that the Company has
15 concluded tax audits with the IRS and the Minnesota Department of Revenue for
16 tax years ending 2010 through 2016. As a result of the audits the Company paid
17 tax and interest on the disputed amounts. The Company has proposed to collect
18 this amount over three years consistent with rate case expenses. (Exhibit BCH-1
19 page 39).

20 **Q. WHAT ADJUSTMENTS DO YOU HAVE REGARDING THE COMPANY'S GAS**
21 **INCOME TAX TRACKER?**

22 **A.** My adjustment to the Company Gas Income Tax Tracker – ND is to remove this
23 balance of approximately \$23,000. The Company has proposed to earn a return
24 on the unamortized balance and also recover this through an amortization expense
25 of \$9,317 over a three-year period. The Company should not be able to earn a
26 return on taxes and interest (carrying costs) and also recover the unamortized
27 balance through the cost of service (amortization expense). Typically these types
28 of costs should only be recovered through an amortization expense. There is no
29 reason why the Company should earn a return and carrying costs that are related
30 to the payment of taxes and interest liabilities (penalties). These audits were for
31 the period (tax years) ending 2010-2016. My adjustment removes \$23,000 from

1 the Company's Regulatory Amortization balance. This adjustment is shown on
2 Schedule DM-3.

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4 **V. Operating Income Issues**

5 **A. Operating Revenues**

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

8 **A.** The Company has proposed Operating Revenues at Present Rates of
9 \$67,853,000 as shown on Exhibit BCH-1 Schedule 3A. The Gas Retail Revenues
10 are comprised of \$67,303,000 plus Other Operating Revenues of \$550,000.

11 **Q. HAS THE COMPANY EXPERIENCED ANY IMPACT RELATED TO THE COVID-**
12 **19 PANDEMIC?**

13 **A.** Company witness Marks stated that the COVID-19 Pandemic negatively impacted
14 the North Dakota economy in 2020. Non-farm employment declined 12.3 percent.
15 While 2020 experienced the greatest economic impact from the pandemic, the
16 effects will linger throughout 2021 and into the 2022 test year. (Exhibit JEM-1 page
17 4). Mr. Marks stated that customer count increased by 1.9 percent in 2020 and
18 sales increased by 0.6 percent with Residential sales increasing 3.0 percent and
19 Commercial and Industrial and Interruptible sales decreasing 0.3 percent. (Exhibit
20 JEM-1 page 5). Mr. Mark's expected a reduction in Residential Sales in 2021
21 relative to the pandemic – inflation levels seen in 2020, and a modest increase in
22 2022. (Exhibit JEM-1 page 6).

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

25 **A.** The Company has utilized a 15-year weather normalization period (Exhibit JEM-1
26 page 9). Mr. Marks stated that after normalizing for weather, the Company's total
27 gas sales have increased an average 2.4 percent per year during the period 2007-
28 2022, with declines in only two years (Exhibit JEM-1 page 9).

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

1 **A.** No, I am accepting the Company's Present Rate Revenues.

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3 **B. Operating and Maintenance Expenses**

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

6 **A.** As shown on Exhibit BCH-1 Schedule 3A, the Company proposed a total
7 Operating and Maintenance Expense (O&M) balance for the 2022 test year of
8 \$54,365,000. This balance is composed of various accounts related to Purchased
9 Gas, Gas Production and Storage, Gas Transmission, Distribution, Customer
10 Accounting/Customer Service, Sale/Economic Development and Administrative
11 and General. This balance includes the Company specific adjustments in each of
12 the accounts listed above, and as shown on Exhibit BCH-1 Revised Schedule 6.

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

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

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

22 **A.** A review of the Company's O&M Expenses shows that certain of the Company's
23 balances for the periods 2019-2021 (Data Request 01-034 Attachment A) fluctuate
24 and vary from year to year. In other accounts, the balances during the same period
25 appear to be abnormal and irregular from what the Company is proposing to utilize
26 and set in the test year 2022 period. In other areas there are negative balances
27 or no prior costs accounted for. Data Request 01-034 reflects these fluctuations
28 and variabilities from year to year. A further inquiry of certain expense breakdown
29 categories were asked for and received in Data Request 4-12, 4,13 and 4-14. The
30 use of a three-year normalization period smooths out fluctuations in setting rates

1 going forward. Prior costs can also show and provide a trend of expenses that
2 were incurred by the Company to determine the reasonableness of the
3 adjustments in costs going forward.

4 It is appropriate to normalize these types of costs to set rates in this proceeding.
5 Finally, certain costs are usually out of the Company's control in that they relate to
6 outside vendors or third-party providers.

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

9 **A.** Yes. In response to Data Request 04-012, 04-013 and 04-014, I asked the
10 Company for a description regarding certain fluctuations. These will be addressed
11 under Section 2, 4 and 5.

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

14 **A.** As more fully reflected on Schedule DM-10, my three-year normalization
15 adjustments (which does not include labor adjustments) is an overall decrease of
16 \$1,234,735, or an overall O&M Expense balance of \$49,037,537, from the
17 Company's proposed balance of \$50,272,272, not including the specific
18 adjustments as outlined in my testimony below under each Expense category, and
19 without labor costs.

20 **Q. PLEASE ADDRESS YOUR AVERAGING ADJUSTMENTS UNDER EACH**
21 **EXPENSE CATEGORY.**

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

23
24 **1. Gas Production & Storage**

25 **Q. WHAT IS YOUR ADJUSTMENT TO THE COMPANY'S GAS PRODUCTION &**
26 **STORAGE EXPENSE?**

27 **A.** In response to Data Request 4-12, I asked the Company for an explanation of the
28 variability related to its Gas Production and Storage balance from \$2.1 million in
29 2019 to \$289,000 in 2022. The Company responded by stating that the difference

1 is related to the Company's \$1.25 million of MGP amortization which was not
2 included in the 2021-2022 rate case data in the direct testimony of Mr. Halama.
3 The actual 2019 Gas Production and Storage Expense also included \$242,000 in
4 MGP clean-up costs the Company agreed to expense in the event it earned more
5 than the authorized ROE during the remediation phase of the project. Given this
6 information I am accepting the Company's Gas Production and Storage balance
7 of \$289,000.

8 2. Transmission Expense

9 **Q. WHAT IS INCLUDED IN THE COMPANY'S GAS TRANSMISSION EXPENSE?**

10 **A.** As shown on Data Response 01-034 Attachment A the Company proposed a
11 balance of \$304,359 for the test year ending 2022.

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

14 **A.** As shown in response to 01-034 Attachment A, the Company has recorded Gas
15 Transmission costs of \$246,098 in 2010, \$239,491 in 2020 and \$294,982 in 2021.

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

17 **A.** I am recommending averaging out or normalizing these costs over a three-year
18 period from 2019-2021. This reduces the balance by \$44,169. This is shown on
19 my Schedule DM-10.

20 3. Gas Distribution

21 **Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS GAS**
22 **DISTRIBUTION EXPENSE?**

23 **A.** As shown in Data Response 01-034 Attachment A, the Company proposed Gas
24 Distribution Expense of \$3,278,109 for the test year period ending 2022. This
25 balance does not include Labor Costs.

26 **Q. WHAT HAS BEEN THE AVERAGE GAS DISTRIBUTION EXPENSE IN PRIOR**
27 **YEARS?**

28 **A.** The Company recorded \$1,890,632 in 2019, \$1,965,662 in 2020 and \$3,274,274
29 in 2021.

1 **Q. WHAT HAS THE COMPANY STATED WAS THE CAUSE FOR THE**
2 **VARIABILITY?**

3 **A.** In response to 4-13, the Company stated that the variability related to MNND
4 Border costs, GCustomer costs and GDirectND costs were due to volatility in
5 actual expenses, including weather and weather related incidents, damage
6 prevention locate volumes, contractor prices and compliance requirements. The
7 Company stated that forecasted O&M data in the years 2021 and 2022 reflect
8 estimates related to proposed work in the forecasted year(s) and developed at a
9 high level and therefore does not provide the same level of cost differentiation by
10 allocated methods. The Company stated that comparisons between actual and
11 forecasted O&M at a refined level such as labor/non-labor or jurisdictional
12 allocators may show deviations that do not exist when the O&M Expense is
13 compared in total.

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

15 **A.** I am recommending normalizing these costs by averaging these out for the periods
16 (2019-2021). These types of costs that the Company has described above, do vary
17 from year to year and are caused by many difference factors including weather,
18 damage prevention locate volumes, contractor pricing and compliance
19 requirements. Smoothing out these fluctuations provide for an overall level of
20 recurring expenses and cost recoveries going forward. My normalization
21 adjustment is a reduction of \$901,252 and is shown on my Schedule DM-15,
22 broken down by MNND Border, G Customers and G Direct ND categories.

23

24

4. Customer Accounting

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

27 **A.** The Company has proposed a Customer Accounting balance for the test year 2022
28 of \$1,217,726 shown in Data Response 01-034 Attachment A. These costs
29 include Bad Debts, Customer related expenses and Direct charges to North

1 Dakota. Total costs assigned to this category including Labor Costs were
2 \$1,612,721 as shown in Data Request 01-34 Attachment A.

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

5 **A.** As explained in Data Response 01-10, the Company has experienced higher
6 uncollectible accounts expense in the period during the COVID-19 pandemic when
7 compared to pre-pandemic period. The Company has recorded incremental
8 provisions amounts monthly to recognize the additional risk of accounts becoming
9 uncollectible due to the impact of the COVID-19 pandemic. In response to Data
10 Request 4-14, the Company stated that these types of costs are directly assigned
11 to jurisdiction whenever possible, and costs are directly assigned to the North
12 Dakota jurisdiction using the GDirectND jurisdiction allocator. The Company broke
13 down these costs further to show the costs related to Labor, Meter Reading,
14 Records and Collections, Uncollectible Bad Debt and Miscellaneous. (04-14
15 Attachment A).

16
17 **Q. WHAT ADJUSTMENTS DO YOU HAVE WITH RESPECT TO THE COMPANY'S**
18 **CUSTOMER ACCOUNTING EXPENSE?**

19 **A.** I am normalizing the Company's Bad Debt Expense over a three-year period
20 (2019-2021). This increases the Company's costs by \$4,204. My next adjustment
21 is related to costs related to Supervision, Meter Reading, Record and Collections
22 and Miscellaneous costs. Normalizing these cost by averaging them out using a
23 three-year (2019-2021) average, results in a reduction of \$191,159. My final
24 adjustment is related to Direct Costs assigned to the North Dakota jurisdiction
25 related to Meter Reading Expenses and Miscellaneous Costs. Normalizing these
26 costs by averaging them out using a three-year (2019-2021) average results in a
27 reduction of \$114,312. My total Customer Accounting Expense adjustment is an
28 overall decrease from \$1,217,726 to \$916,459 or a reduction of \$301,267.

29
30 **5. Customer Service & Information Expense**

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

3 **A.** I used a simple average of these costs for the periods 2019-2021. The Company
4 has proposed a balance of \$140,217 for the test year 2022. My three-year average
5 adjusts the balance to an increase of \$11,853 and a proposed 2022 balance of
6 \$152,070. This balance is shown on Schedule DM-10.

7

8 **6. Sales, Economic Development and Other Expenses**

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

11 **A.** While I did not average out the Company's balance of \$8,872, I do have an
12 adjustment related to the Company's Economic Development Donations of
13 \$7,382. This adjustment will be addressed under Section I of my testimony below.
14 This balance is shown on Schedule DM-10.

15 **7. Administrative & General Expenses**

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

18 **A.** While I did not average out the Company's balance of \$1,099,071, I do have
19 adjustments related to several of the Company Precedential and Ratemaking
20 Adjustments, which will be addressed under Section J of my testimony below. My
21 balance is shown on my Schedule DM-10.

22 **C. Purchased Gas Expenses**

23 **Q. WHAT ADJUSTMENTS DO YOU HAVE REGARDING THE COMPANY'S**
24 **PROPOSED PURCHASED GAS EXPENSES?**

25 **A.** In reviewing the Company's filing and related data responses to Purchased Gas
26 Expenses, I am accepting the Company's balance \$43,934,000 as shown on
27 Company Exhibit BCH-1 Schedule 3A.

28

1 **D. Gas Production & Storage Expenses**

2 **Q. WHAT SPECIFIC ADJUSTMENTS DO YOU HAVE REGARDING THE**
3 **COMPANY'S REMAINING PROPOSED GAS PRODUCTION & STORAGE**
4 **EXPENSES?**

5 **A.** In reviewing the Company's filing and related data responses to Gas Production &
6 Storage Expenses, I am accepting the Company's remaining Gas Production &
7 Storage Expenses.

8
9 **E. Gas Transmission Expenses**

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

12 **A.** The Company has initiated a Damage Prevention Program (DPP) that assigns
13 costs to the Company's Transmission, Distribution, Customer Service and A&G
14 expense categories (Data Response 1-53 Attachment A). The Company stated
15 that the DPP helps excavators and customers locate underground gas
16 infrastructure to avoid accidental damage and safety incidents. (Exhibit JLZ-1
17 testimony page 37). The Company contracts with and relies on internal labor and
18 contractors to implement the DPP, of which the primary purpose is to reduce
19 damage to Company – owned buried facilities caused by excavation. This
20 requirement is further supplemented by state law in North Dakota. (Exhibit JLZ-1
21 testimony page 37). This program is designed to ensure compliance with state and
22 federal regulations and NSP relies heavily on contractors to perform this work. The
23 Company has stated that damage prevention costs have increased by \$400,000
24 between 2019 and 2020 actuals and are further forecasted to increase by
25 \$100,000 between 2020 and 2021, due to the increases attributable to both an
26 increase in the volume of underground locate requests and a higher contract cost
27 per locate due to contractor cost increases. (JLZ-1 testimony page 37-38).

28
29 **Q. WHAT HAS THE COMPANY PROVIDED TO SHOW THESE COSTS RELATED**
30 **TO THE DPP?**

1 **A.** The Company provided breakdown these costs by account number for the periods
2 2019-2020 actuals, forecasted 221 and FTY 2022. (Data Response 1-53
3 Attachment A).

4 **Q. WHAT DOES THIS DATA RESPONSE SHOW OR INDICATE?**

5 **A.** According to the data response 1-53 Attachment A, the majority of the dollar
6 amount related to the DPP were recorded in the Gas Distribution category,
7 particularly in Account No. 874 where the initial cost of this program was \$577,153
8 and increases to \$1,131,448 through the FTY 2022. The costs accounted for
9 under the Gas Transmission Expense category (Accounts 851 and 856) were
10 minimal and no projected expenses were proposed in FTY 2022.

11 **Q. WHAT ARE YOUR ADJUSTMENTS RELATED TO THE DPP FOR THE
12 COMPANY'S GAS TRANSMISSION EXPENSE?**

13 **A.** I am not recommending any adjustment to the Company's Gas Transmission
14 Expense related to the DPP as the Company did not project any costs in the
15 Forecasted 2021 and the FTY 2022.

16

17 **F. Gas Distribution Expenses**

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

20 **A.** As previously discussed above under the Gas Transmission Expense, the
21 Company has proposed costs related to its DPP in the amount of \$1,131,448 (Data
22 Response 1-53 Attachment A). This expenses is solely related to Distribution
23 Expense – Mains and Services under Account 874.

24 **Q. WHAT ARE YOUR ADJUSTMENTS RELATED TO THE COMPANY'S DPP?**

25 **A.** I am normalizing this expense by averaging these costs over three years (2019-
26 2021). The Company has provided actual cost for the DPP (2019-2020) and
27 forecasted costs for 2021 and in 2022. Given that the Company's 2021 cost
28 increase was forecasted due to vendor contracts expiring, the labor market was

1 tight, and insurance premiums increased, and that inaccurate locates performed
2 by Company employees increased, costs should remain consistent and in line with
3 prior costs. The Company is expected to utilize outside contractors as any
4 damages that will occur will be covered by the vendors and not the Company or
5 its employees. (JLZ- 1 testimony page 37). Normalizing these costs over a three
6 year average reduces the balance by \$245,950. This is shown on my Schedule
7 DM-15.

8
9 **G. Customer Accounting Expenses**

10 **Q. WHAT ADJUSTMENTS HAS THE COMPANY PROPOSED WITH RESPECT TO**
11 **ITS CUSTOMER ACCOUNTING EXPENSES?**

12 **A.** The Company did not propose any specific adjustment to its Customer Accounting
13 Expenses. As discussed previously, the only adjustments that I have are related
14 to normalizing certain costs using a three year average.

15
16 **H. Customer Service & Information Expenses**

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

19 **A.** The Company removed \$40,000 related to its Advertising Expense (WP-A1 and
20 Company Exhibit BCH-1 Schedule 4). The Advertising Expense was related to
21 Conservation DSM costs.

22 **Q. WHAT WERE THE COMPANY'S TOTAL ADVERTISING COSTS PROPOSED**
23 **IN 2022?**

24 **A.** As shown on Workpaper A1-Advertising, the Company recorded total Advertising
25 Costs of \$100,071. The remaining Advertising Costs included were related to
26 Customer Assistance, Informational and Instructional expense, Economic
27 Development and A&G General Advertising.

28 **Q. WHAT ADJUSTMENTS DO YOU HAVE REGARDING THE COMPANY'S**
29 **CUSTOMER SERVICE & INFORMATION EXPENSE – ADVERTISING?**

1 **A.** I am removing \$1,471 of Advertising Expense that is related to Economic
2 Development. Since I am recommending removing Economic Development
3 Donations under the Company's Sales, Economic Development & Other
4 Expenses, I am recommending that these costs under Advertising should also be
5 removed. My arguments for removing these costs are as outlined below under
6 Section I. My recommendation is shown on my Schedule DM-17.

7

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

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

11 **A.** As shown on Exhibit BCH-1 Schedule 4 and Schedule 6, the Company proposed
12 an adjustment related to Economic Donations in the amount of \$7,382. A
13 breakdown of these balance is shown on Workpaper A11. (portion allocation to
14 ND Gas Jurisdiction).

15 **Q. WHAT IS INCLUDED IN THE COMPANY'S \$7,382 ECONOMIC**
16 **DEVELOPMENT DONATIONS?**

17 **A.** Company Witness Mr. Halama (Exhibit BCH-1 page 37) stated that the Company
18 makes contributions to a number of regional and local economic development
19 organizations positioned to combine resources for the purposes of maintaining and
20 improving the long-term economic health of communities in its service territory or
21 retaining employment opportunities and expanding the state and local tax base. In
22 response to NDPSC 1-41, these costs provide financial and collaborative support
23 to local, regional and state organizations. It is an estimate. These costs are used
24 to assist in the strategic advancement of the communities served by the Company
25 for job creation, GDP growth and the overall social well-being for individuals and
26 businesses. Because no 2022 contributions had been made at the time of filing,
27 there is no further breakdown or description of these donations.

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

1 **A.** I do not believe that ratepayers should pay for these types of costs in rates. These
2 expense items are akin to charitable contributions. The Company is a utility
3 company providing gas utility service to certain parts of North Dakota. The
4 Company should not be expensing costs related to non-utility type services, nor
5 be in a position to support regional and local economic development. These type
6 of initiatives should be provided at the State and Local or even at the Federal level.
7 Additionally, ratepayers do not have a say in what type of donations they are
8 paying for, or whether ratepayers receive any benefit for these contributions.
9 These types of costs should not be included in the revenue requirement proposed
10 by the Company. Given that no 2022 contributions had been made at the time of
11 filing, there is no way to determine exactly how much money was expended in the
12 FTY 2022. The Company should pay for these costs, below the line, and receive
13 the tax benefits through the corporate entity.

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

15 **A.** I am recommending removal of the \$7,382 of Economic Development Donations
16 from the Company's Sales, Economic Development and Other Expenses balance.
17 This is shown on Schedule DM-18.

18

19 **J. Administrative & General Expenses**

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

22 **A.** As shown on Exhibit BCH-1 Schedule 4 and 6, the Company proposed an
23 Unadjusted Balance of \$2,638,502, Precedential Adjustments of (\$145,568) and
24 Ratemaking Adjustments of \$14,483, computing to Adjusted Balance of
25 \$2,507,656. These adjustments reflect Precedential Adjustments which the
26 Company has not changed from the Commission's Order in the Company's
27 previous completed electric rate cases (Exhibit BCH-1 page 34). The Company
28 has also reflected Ratemaking Adjustments that relate to specific adjustments in
29 this instant proceeding. I will address each of these Precedential and Ratemaking
30 Adjustments below.

1 Q. WHAT SPECIFIC PRECEDENTIAL ADJUSTMENTS HAS THE COMPANY
2 PROPOSED IN THIS PROCEEDING?

3 A. The Company has proposed the following Precedential Adjustments:

4 **Precedential Adjustments**

5	Advertising -	(\$ 28,856)	WP A1
6	Customer Deposits -	\$ 676	WP A3
7	Incentive Pay	(\$ 17,013)	WP A4
8	Incentive Pay LTI	(\$ 97,348)	WP A5
9	SERP -	(\$ 3,027)	WP A6

10

11 Q. WHAT ADJUSTMENTS DO YOU HAVE REGARDING THE COMPANY'S
12 PRECEDENTIAL ADJUSTMENTS?

13 A. I have reviewed each of the Company's Precedential Adjustments, and I am
14 accepting the Company's adjustments totaling (\$145,568). This is shown on my
15 Schedule DM-19.

16

17 Q. WHAT ARE THE OTHER SPECIFIC ADJUSTMENTS HAS THE COMPANY
18 PROPOSED IN THIS PROCEEDING?

19 A. The Company has proposed five Ratemaking Adjustments:

20 **Ratemaking Adjustments**

21	a. Aviation	(\$22,003)	WP A7
22	b. Dues - Chamber of Commerce	\$ 2,221	WP A10
23	c. Economic Development Donations	\$6,226	WP A12
24	d. Incentive Pay – Environ. LTI	\$17,060	WP A13
25	e. Incentive Pay – Time Based LTI	\$10,979	WP A14

26

27 Q. WHAT ADJUSTMENTS DO YOU HAVE REGARDING THE COMPANY'S
28 RATEMAKING ADJUSTMENTS ABOVE?

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

- 31 a. Chamber of Commerce Dues – (\$2,221)
32 b. Economic Development Donations – (\$6,226)
33 c. Incentive Pay Environmental LTI –
34 d. Incentive Pay Time Based LTI -

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a. Dues - Chambers of Commerce

Q. WHAT HAS THE COMPANY INCLUDED IN ITS CHAMBERS OF COMMERCE?

A. The Company has included \$2,221 of Chamber of Commerce Dues in revenue requirement request. (Workpaper A10 and Company Exhibit BCH-1 Schedule 4). Company witness Mr. Halama stated that these costs provide an essential link between the Company and the communities it serves and facilitate improved utility service (BCH-1 testimony page 36). Mr. Halama stated that because membership in these organizations provide benefits to all utility customers, recovery of membership dues paid to Chambers of Commerce is appropriate. (Exhibit BCH-1 page 36).

Q. WHAT ARE YOUR ADJUSTMENTS?

A. I am recommending no recovery because this type of cost does not benefit North Dakota ratepayers. This cost mainly serves to advance the policy positions before State and Governmental agencies and to communicate its corporate citizenship initiatives. Ratepayers should not be required to pay for such costs which provide no benefit to utility service. I am recommending removal the Company's Chamber of Commerce costs of \$2,221. Further, in response to Data Request 1-40, The Company has indicated that no 2022 contributions have been made and no breakdown can be provided.

b. Economic Development Donations

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

A. The Company has included \$6,226 of costs related to Economic Donations. Company witness Mr. Halama stated that the Company makes contributions to a number of regional and local economic development organizations positioned to combine resources for the purpose of maintaining and improving the long-term health of communities in its service territory or retaining employment opportunities and expanding the state and local tax base. (Exhibit BCH-1 testimony page 37). .

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

2 **A.** I am recommending that the \$6,226 costs related to Economic Development
3 Donations be removed from the Company's costs of service. In response to Data
4 Request 1-42, the Company has not contribution any dollars in 2022 and there is
5 not breakdown of these costs. These costs are similar to Charitable Contributions,
6 and in general, should be removed from the Company's cost of service because
7 ratepayers do not have any say of what type of contributions they are paying for.
8 These types of payments do not benefit ratepayers, and as I stated previously in
9 my testimony, and only benefits the Company as being good corporate citizens.
10 These costs should be funded below the line by the shareholders of the Company
11 and receive a tax benefit through the corporate entity. The Company does not
12 have the right to make others pay for charitable contributions, especially those
13 costs that do not provide specific benefits to its ratepayers. My recommendation is
14 shown on my Schedule DM-19.

15 c. Incentive Pay – Environmental LTI

16 **Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO INCENTIVE PAY**
17 **– ENVIRONMENTAL LTI?**

18 **A.** According to Company witness Mr. Chamberlain, the Company is seeking to adjust
19 recovery in rates for the Long-Term Incentive program (LTI) in the amount of
20 \$17,060 for its Environmental LTI. (Exhibit GPC-1 testimony page 22) (Exhibit
21 BCH-1 Schedule 4) (WP A13). The LTI is available to the Company's senior and
22 executive level employees, of which less than five percent of exempt and non-
23 bargaining employees are eligible for LTI. The LTI is intended to incentivize these
24 senior employees to effectively manage the Company towards its overall goals and
25 in the best interest of customers and shareholders. The LTI is geared toward
26 employees who have a higher influence in the Company's direction and strategy.
27 (Exhibit GPC-1 testimony page 22). The LTI program helps retain key employees
28 and is necessary for Xcel Energy to remain competitive in the labor market.
29 (Exhibit GPC-1 testimony page 22). The Environment portion is tied into achieving
30 the Company's environmental goals which will result in efficiencies, allow for a

1 lower cost of capital and remove fuel costs in addition to environmental benefits
2 and other benefits. (Exhibit GPC-1 testimony page 23).

3 **Q. DID THE COMPANY PROVIDE ANY INFORMATION WITH RESPECT TO GOAL**
4 **ACHIEVEMENT AND SCORECARD RESULTS?**

5 **A.** In response to Data Request 1-14, the Company stated that 2021 Corporate
6 Scorecard final results have not yet been calculated and approved. The Company
7 stated that 2021 Scorecard will determine the payout anticipated on March 9, 2022.
8 (Data Response 1-15). The Company stated that the LTI plans requires a three-
9 year service commitment with the Company which typically occurs in February
10 following the third year of vesting. (Data Response 1-13 and 14).

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

12 **A.** Given that the Company's Corporate Scorecard final results will not occur until
13 March 2022, the Company's proposed Annual Incentive related to Environmental
14 LTI is unknown and not measurable. Also, these Annual Incentive costs are
15 geared toward senior and executive level employees from preventing them from
16 leaving the Company, and to maintain and retain these employees as hiring these
17 types of employees are expensive and time-consuming to fill. (Exhibit GPC-1
18 testimony page 22). In response to Data Request 1-16, the Company provide a
19 schedule of senior and executive employees who left the Company. In the past
20 three years (2019-2021) the Company experienced 2 non-retirement leaves and
21 zero retirement leaves for the NSPM total Company. The Company does not track
22 reasons for terminating employment beyond retirement and these are allocated
23 across each of the associated jurisdictions. Therefore, I am recommending that
24 the Company's Environmental LTI of \$17,060 be removed from the Company's
25 A&G expenses. (add more language, discuss with Advocacy Staff). My
26 recommendation is shown on my Schedule DM-19.

27 d. Incentive Pay – Time Based LTI

28 **Q. WHAT HAS THE COMPANY PROPOSED RELATED TO ITS TIME BASE LTI?**

1 **A.** The Company has proposed to recover \$10,979 based upon an LTI which is a
2 program tied to the length of key employee's service with the Company. The
3 Company stated that it benefits from its ability to retain institutional knowledge and
4 capabilities of key employees. (Exhibit GPC-1 testimony page 23) (Exhibit BCH-1
5 Schedule 4) (Workpaper A14).

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

7 **A.** As more fully discussed above, I am also recommending that the Company's
8 \$10,979 related to Time Based LTI be removed from the Company's A&G
9 expenses. These costs are not known and measurable as the Company has not
10 finalized its Scorecard which would determine the payout. This will occur on March
11 9, 2022. (Data Response 1-15). **(add more language as needed, discuss with**
12 **Advocacy Staff)**. My recommendation is shown on my Schedule DM-19.

13 **K. Labor Adjustments**

14 **Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO LABOR**
15 **EXPENSE?**

16 **A.** As shown on Data Response to 01-034 Attachment A, the Company proposed
17 total Labor Expense of \$4,093,208 for all employee categories. The Company
18 allocated these labor costs by direct assignment or allocated to the North Dakota
19 Gas Utility operations. (Exhibit BCH-1 testimony page 25 and 29). The cost
20 allocation and assignment principles are consistent with the Company's recent
21 North Dakota electric rate case filed on November 6, 2020 in Case No. PU-20-441.
22 (Exhibit BCH-1 testimony page 29).

23 **Q. DID THE COMPANY PROVIDE A SCHEDULE OF EMPLOYEES EXPECTED TO**
24 **BE HIRED BY NSPC-GAS COMPANY IN THE PROJECTED YEAR 2022?**

25 **A.** Yes. In response to Data Request 1-19, the Company provided a schedule of
26 employees as potential candidates. Positions will be filled as soon as possible,
27 but the specific dates are not known. The Company stated that the position list will
28 also continue to change throughout the year. The Company stated that it cannot
29 determine the anticipated hire data for the specific opening.

1 **Q. HAS THE COMPANY PERFORMED A VACANCY RATE ANALYSIS FOR THE**
2 **NSPC- GAS UTILITY OPERATIONS?**

3 **A.** No. The Company stated in response to Data Request 1-18, that it works with
4 leaders in certain areas regarding attrition and the need for posting open positions,
5 the Company does not conduct a formal vacancy rate analysis.

6 **Q. WHAT APPROACH HAVE YOU DETERMINED TO ADJUST LABOR COSTS?**

7 **A.** I am recommending an adjustment of labor for all O&M labor by functional group
8 by the use of a vacancy rate analysis. I relied on the Company's response to
9 NDPSC 01-034 Attachment which shows the labor costs allocated to the North
10 Dakota's Gas jurisdiction, by Operating Expense account. I relied on the response
11 to Data Requests 1-20 that shows the employee headcount of NSPM-Minnesota
12 for the years 2019-2022. The response to 1-6 which asked for the allocation of
13 employees related to the North Dakota jurisdiction – Gas Utility for the years 2019
14 – 2022, refers me to Mr. Halama's Exhibit BCH-1 Schedule 12. Finally I reviewed
15 the Company's response to Data Request 1-17 which reflects the level of
16 employees who have left the Company (Non-Retirement and Retirement). Given
17 that the Company allocates its labor costs by jurisdictional allocation, and these
18 can vary from year to year, it is appropriate to adjust these labor costs
19 prospectively. Labor costs can vary from year to year in each of NSPM's service
20 territories and depending on the circumstances and the need to allocate labor,
21 costs can vary.

22 **Q. HOW DID YOU ADJUSTMENT TO THE COMPANY'S TOTAL LABOR COSTS?**

23 **A.** I began with the number of employees of NSPM – Minnesota (Data Response 1-
24 20) which shows the number of employees from 2019 through 2022. I then
25 allocated these balances by the allocation factor of 11.2872% as shown on Exhibit
26 BCH-1 Schedule 12 to reflect the number of employees allocated to the North
27 Dakota – Gas Operations:

	<u>NSPM</u>	<u>Factor</u>	<u>Allocated to NSPM-ND-Gas</u>
28			
29			
30	2019 3,186	11.2872%	359
31	2020 3,118	11.2872%	352

1	2021	3,285	11.2872%	371
2	2022	3,266	11.2872%	369

3

4 I then reviewed the response to Data Request 1-17 which shows the number of
 5 NSPM total employees who have left the Company. I divided the number of
 6 employees allocated to the North Dakota – Gas Operations in each year by the
 7 number of employees who have left the Company to arrive at a vacancy rate as
 8 follows:

				<u>Ratio to Total</u>	<u>3 Yr. Avg</u>
10	2019	120	11.2872%	14	3.899%
11	2020	112	11.2872%	13	3.693%
12	2021	171	11.2872%	19	5.121%
13					4.2366%

14

15 **Q. WHAT WERE YOUR NEXT STEPS?**

16 **A.** I then took the three year average of 4.2366% and multiplied that ratio by the total
 17 Labor costs allocated to the North Dakota – Gas Operations of \$4,093,208 shown
 18 on Data Request 1-34 Attachment A to arrive at a vacancy adjustment of \$173,412.
 19 This is shown on my Schedule DM-4.

20

21

22

23 **L. Depreciation Expenses**

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

26 **A.** The Company proposed an Unadjusted Depreciation Expense balance of
 27 \$6,845,000 as shown on Exhibit BCH-1 Schedule 6. The Company proposed an
 28 adjustment of (\$31,918) related to Remaining Life for Gas Manufactured
 29 Production Plant and Gas Other Storage plant. (WP A8) The Company proposed
 30 an adjustment of \$78,123 related to a Depreciation Study for its plant balances

1 (WP A9). According to Ms. Wold in her testimony Exhibit LJW-1 page 2, these
2 adjustments reduced the Depreciation Expense at the North Dakota jurisdiction by
3 \$19,000.

4 **Q. WHAT ADJUSTMENTS DID THE COMPANY INCORPORATE THAT**
5 **RESULTED IN A REDUCTION OF DEPRECIATION EXPENSE?**

6 **A.** According to Ms. Wold the increase in service lives and changes in net salvage
7 rates decreased the Gas Production and Storage Depreciation by about 32,000
8 (LJW-1 testimony page 2). Gas Depreciation expenses were decreased by
9 \$49,000 in the allocation portion of Common Utility assets and partially offset by
10 \$62,000 for the North Dakota jurisdiction that increased Depreciation expense for
11 Gas Transmission, Distribution and General assets. (LJW-1 testimony page 3,
12 and Table 1 page 3 and Table 2 page 11).

13
14 **Q. WHAT ADJUSTMENT DO YOU HAVE WITH RESPECT TO THE COMPANY'S**
15 **DEPRECIATION EXPENSE?**

16 **A.** While I do not have any adjustments related to the Company's Depreciation Study
17 and Remaining Life Adjustments, I do have an adjustment related to the removal
18 of certain plant additions. Since I removed costs related to certain inflation
19 increases and contingency factors that I discussed under my Gas Plant In Service
20 Testimony, I am removing the associated Depreciation Expense. I utilized the
21 Company's composite rate of Depreciation which was computed by the information
22 responded to in Data Request 1-61 (Exhibit LJW-1 Schedule 9), which calculates
23 out to 2.646%. I then multiplied the adjustment to the Gas Plant Additions of
24 \$607,617 times the Composite Depreciation rate of 2.646% to arrive at an
25 adjustment of \$16,078. This is shown on my Schedule DM-20.

26
27 **M. Amortization Expense**

28 **Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS**
29 **AMORTIZATION EXPENSE?**

1 **A.** The Company has proposed a total Amortization Expense of \$439,979 (Exhibit
2 BCH-1 Schedule 6). The breakdown is as follows:

3

4	a).	Income Tax Tracker	\$ 9,317
5	b).	NOL ADIT ARAM	\$ 22,547
6	c).	Rate Case Expenses	<u>\$408,115</u>
7		Total	\$439,979

8

9 a). Income Tax Tracker - \$9,317

10 **Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS INCOME**
11 **TAX TRACKER OF \$9,317?**

12 **A.** The Company stated that it has concluded tax audits with the IRS and the
13 Minnesota Department of Revenue for tax years 2010-2016, and as a result of the
14 audits, the Company paid tax and interest on the disputed amounts. The Company
15 is proposing to recover these costs over a three year period consistent with rate
16 case expenses (Exhibit BCH-1 testimony page 39). (\$27,951/3). (WP A15).

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

18 **A.** I am accepting the Company's Income Tax Tracker proposal, and the costs
19 allocated to the North Dakota jurisdiction of \$27,951. I am recommending an
20 amortization period of 5 years instead of 3 years. This will allow the Company to
21 recover its Income Tax Tracker costs between normalized rate case proceedings.
22 In determining the 5-year period, I relied on the Company's prior rate case
23 applications with the ND Commission which reflected electric rate case filings in
24 2001, 2004, 2006 and 2021. (Data Response 1-23). The Company has filed rate
25 case petitions on average every five-years. I normalized the period between rate
26 cases (2001-2021) and arrived at an average 5-year period between rate cases.
27 This results in an annual recovery of \$5,590. This is shown on Schedule DM-21.

28

29 b). NOL ADIT ARAM - \$22,547
30

1 **Q. WHAT HAS THE COMPANY PROPOSED WITH RESPECT TO ITS NET**
2 **OPERATING LOSS, ACCUMULATED DEFERRED INCOME TAXES,**
3 **AVERAGE RATE ASSUMPTION METHOD OF \$22,547?**

4 **A.** The Company is proposing to amortize the NOL ADIT ARAM over a 23-year
5 period. The Commission's Order in PU-18-156 approved the Company's proposed
6 amortization level included in the Tax Cuts and Jobs Act (TCJA) refund calculation.
7 (Exhibit BCH-1 testimony page 39). (WP A16).

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

9 **A.** I am accepting the Company's proposal related to the \$22,547 amortization
10 expense related to the NOL ADIT ARAM. My adjustment is shown on Schedule
11 DM-21.

12 c). Rate Case Expenses \$408,115

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

15 **A.** The Company has proposed to recover about \$1.224 million (\$1.224 million / 3
16 three years or \$408,000) of projected direct costs associated with this rate case
17 docket and a three-year amortization period. (Exhibit BCH-1 testimony page 40).
18 (WP A17).

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

20 **A.** I am accepting the Company's proposed rate case expense balance of \$1.224
21 million. My only adjustment is to extend the amortization period to 5 years
22 consistent with my recommended amortization period for other amortizations in
23 this rate proceeding. This reduces the expense from \$408,115 to \$244,869, a
24 reduction of \$163,246. My adjustment is shown on Schedule DM-21.

25
26
27

N. Taxes Other Than Income Taxes

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

3 **A.** As shown on Company Exhibit Schedule 3A page 2 of 6, and in Exhibit BCH-1
4 Schedule 6, the Company proposed total Taxes other Than Income Taxes of
5 \$2,401,000.³ The breakdown representing the balance is as follows:

6	a).	Property Taxes – Net	\$1,587,000
7	b).	Deferred Income Taxes	\$ 550,000
8	c).	Payroll – (Adj.)	<u>\$ 263,000</u>
9		Total	\$ 2,401,000

10
11 a). Property Taxes – Net - \$1,587,442

12 **Q. HOW DID THE COMPANY DEVELOP ITS PROPERTY TAX BALANCE OF**
13 **\$1,587,000?**

14 **A.** In response to Public Data Request 1-24, the Company is allocated a portion of its
15 Property Taxes from NSPM-Minnesota. The North Dakota Office of the State Tax
16 Commissioner’s provides property tax valuation and assessment calculations for
17 2019, 2020 and 2021. **(These valuation reports are deemed confidential).** The
18 Company’s Property Taxes reflect what has been allocated to North Dakota
19 including some plant in Minnesota. These valuations do not reflect the full amount
20 of property taxes included in rates.

21 **Q. DO YOU HAVE ANY ADJUSTMENTS TO THE COMPANY PROPERTY TAX**
22 **BALANCE?**

23 **A.** I am recommending averaging out Property Taxes for the periods 2019-2021 and
24 normalizing these costs. The allocations between and among the NSPM
25 Minnesota vary from year to year as shown in the Attached NDPSC Data Request
26 No. 1-024 Attachment A. Therefore, given that the allocations do change from
27 year to year, it may not appear at face value that Property Taxes are increasing
28 from year to year. In the response to the non-confidential Data Response 1-24 the
29 Company’s recorded Property Taxes in 2019 were \$1,301,677. In Company
30 Exhibits BCH-1 Schedules 3C, 3B and 3A, the Company recorded \$1,190,489 of

³ Any differences due to rounding.

1 Property Taxes in 2020, \$1,283,706 of Property Taxes in 2021 and \$1,587,442 of
2 Property Taxes in the 2022 test year period. Given the fluctuations from year to
3 year, I believe it is appropriate to normalize these costs. The three year average
4 calculates to \$1,258,624, (2019 – 2021 Property Tax balances) a reduction of
5 \$328,818 from the Company's proposed balance of \$1,587,442. My
6 recommendation is shown on my Schedule DM-22.

7
8 b). Deferred Income Taxes - \$551,000

9 **Q. HOW DID THE COMPANY DEVELOP ITS DEFERRED INCOME TAXES**
10 **ADJUSTMENT OF \$551,000?**

11 **A.** According to Mr. Halama's testimony (BCH-1) page 25, the Company determined
12 income taxes based on total before book income, tax additions, and deductions
13 which determine deferred income taxes and the resulting taxable income that is
14 used to calculate federal and state income taxes. The Federal Income Tax rate
15 reflects the 21% rate effective January 1, 2018 with the enactment of the TJCA.
16 Mr. Halama stated that net operating losses (NOL) are created when taxable
17 deductions exceed taxable revenues, and when this occurs, the excess deductions
18 are carried forward to future periods. (Halama Testimony BCH-1 page 26). The
19 NOL required an adjustment that offsets the part of the ADIT rate base reduction
20 that is associated with the accelerated depreciation deductions, which is needed
21 to keep the Company's rate base consistent with the income tax deductions that
22 the Company has been able to use. Keeping a balance of rate base reductions
23 from the ADIT and the use of accelerated depreciation is required under Federal
24 income tax law and part of normalization for both accounting and ratemaking.
25 (Halama Testimony BCH-1 page 26).

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

28 **A.** I am accepting the Company balance related to its Deferred Tax balance of
29 \$551,000. Since I did not make any adjustments to the Company's proposed

1 Depreciation Study – Remaining Life and Depreciation Study TD&G, I have no
2 adjustments within these categories.

3
4 c). Payroll – (Adj.) \$263,000

5 **Q. WHAT IS YOUR THIRD ADJUSTMENT PAYROLL TAXES?**

6 **A.** Since I made adjustments to the Company's Labor balance, and Incentive
7 Compensation I am making the associated adjustment to the Company's Payroll
8 Taxes and Others. I utilized the Company's O&M Labor assigned to the North
9 Dakota jurisdiction (NDPSC 1-34 Attachment A) of \$4,093,208 and the Company's
10 proposed Payroll of \$262,844 to arrive at a 6.421% ratio. I then took my
11 adjustments to Labor and Incentive Compensation and multiplied the balance by
12 6.421% to arrive at a Payroll adjustment of \$12,935.

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

15 **A.** My adjustment is a decrease of \$341,753. This is shown on Schedule DM-22.

16
17 **O. State Income Taxes**

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

20 **A.** The Company proposed a State Income Tax Expense of \$275,243 (Schedule DM-
21 23). This is comprised of Current State Income Taxes of (\$29,000) and Proposed
22 State Income Taxes of \$304,243, shown on Exhibit BCH-1 Schedule 3A.

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

24 **A.** The Company computed its State Income Taxes by using the Statutory State Tax
25 Rate of 4.31% (Exhibit BCH-1 Revised Schedule 3A) and multiplying that rate by
26 the proposed Revenue Requirement of \$7,059,000 to arrive at a balance of
27 \$304,243. (Company Exhibit BCH-1 Schedule 11).

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

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

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

6 **A.** My proposed State Income Tax Expense is \$99,883, which is calculated by taking
7 my recommended revenue requirement of \$2,990,332 and multiplying that amount
8 by 4.31% to arrive at a balance of \$128,883. My total State Income Taxes is
9 \$99,883 shown on my Schedule DM-23. The additional State Income Tax is
10 incorporated into my revenue requirement Schedule DM-1 through the Gross
11 Revenue Conversion Factor of 1.322840.

12

13 **P. Federal Income Taxes**

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

16 **A.** The Company has proposed a Federal Income Tax Expense of \$1,283,499. This
17 is comprised of current Federal Income Taxes of (\$135,000) and proposed Federal
18 Income Taxes of \$1,418,499 shown on Company Exhibit BCH-1 Schedule 3A.

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

20 **A.** The Company computed its Federal Income Taxes by using the Statutory Federal
21 Tax Rate of 21.00% (Exhibit BCH-1 Revised Schedule 3A) and multiplying that
22 rate by the Company's proposed Revenue Requirement of \$7,059,000 to arrive at
23 a balance of \$1,418,499.

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

26 **A.** As I calculated the Company's State Income Taxes, I have used the same
27 methodology to calculate the Company's Federal Income Taxes. Using my
28 recommended Revenue Requirement increase of \$2,990,332, I multiplied that
29 amount by 21% to arrive at a proposed Income Tax Expense of \$600,904.

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

2 **A.** My proposed Federal Income Tax Expense is \$465,904. This is shown on my
3 Schedule DM-23. My total proposed balance of \$465,904 includes the Company's
4 current balance of (\$135,000). The additional Federal Income Tax is incorporated
5 into my revenue requirement Schedule DM-1 through the Gross Revenue
6 Conversion Factor of 1.322840.

7

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

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

11

REVENUE REQUIREMENT

		(1)			
		Company Proposed	Adjustments	ND PSC Advocacy Staff	References
1	Average Rate Base	\$ 124,227,000	\$ (1,695,902)	\$ 122,531,098	
2	Present Rate Income	\$ 3,919,000	\$ 2,224,449	\$ 6,143,449	
3	AFUDC	\$ -		\$ -	
4	Total Available for Return	\$ 3,919,000	\$ 2,224,449	\$ 6,143,449	
5	Present Rate of Return	3.155%		5.014%	
6	Required Return	7.450%		6.86%	
7	Operating Income Requirement	\$ 9,254,912	\$ (850,924)	\$ 8,403,988	
8	Income Deficiency	\$ 5,335,912	\$ (3,075,372)	\$ 2,260,539	
9	Gross Revenue Conversion Factor	1.322840		1.322840	(2)
10	Revenue Deficiency	\$ 7,058,557	\$ (4,068,225)	\$ 2,990,332	
11	Present Rate Revenues	\$ 67,303,000		\$ 67,302,687	
12	Percentage Increase	10.488%		4.443%	

Total Revenue Requirement **\$ 70,293,019**

- (1) Company Exhibit BCH-1 Schedule 7
- (2) Company Exhibit BCH-1 Schedule 3A

State Income Tax Rate	4.310000%
Federal Income Tax Rate	21.000000%
Effective Tax Rate	20.090000%
Composite Tax Rate	24.400000%
Revenue Conversion Factor	1.322837

Differences due to rounding

WEIGHTED AVERAGE COST OF CAPITAL

(1) Company Proposed

		Ratios	Cost of Capital	Weighted Average
1	LT Debt	47.03000%	4.09550%	1.92611%
2	ST Debt	0.43000%	1.09000%	0.00469%
3	Common Equity	52.54000%	10.50000%	5.51670%
4	Total Capital	100.00000%		7.44750%
5	rounded			7.45000%

(2) ND PSC Advocacy Staff

6	LT Debt	47.570%	4.100%	1.950%
7	ST Debt	0.430%	1.090%	0.005%
8	Common Equity	52.000%	9.430%	4.904%
9	Total Capital	100.000%		6.86%

(1) Company WP C1

(2) Exhibit MFG-16

<u>AVERAGE RATE BASE</u>		(1)			
		Company	Adjustments	ND PSC	References
		Proposed		Advocacy Staff	
<u>Gas Plant in Service</u>					
1	Production	\$ 5,340,000	\$ -	\$ 5,340,000	
2	Transmission	\$ 3,909,000	\$ -	\$ 3,909,000	
3	Distribution	\$ 181,046,000	\$ (607,617)	\$ 180,438,383	
4	Gas Storage	\$ 9,341,000	\$ -	\$ 9,341,000	
5	General	\$ 14,757,000	\$ -	\$ 14,757,000	
6	Common	\$ 8,463,000	\$ -	\$ 8,463,000	
7	Total Gas Plant In Service	\$ 222,856,000		\$ 222,248,383	
8	Depreciation Reserve	\$ 82,973,000	\$ (16,078)	\$ 82,956,922	
9	Net Gas Plant In Service	\$ 139,883,000	\$ (591,539)	\$ 139,291,461	
10	Gas Plant Held for Future Use	\$ -	\$ -	\$ -	
11	Construction Work in Progress	\$ 188,000	\$ -	\$ 188,000	
12	Accumulated Deferred Income Taxes	\$ 19,783,000	\$ (4,376)	\$ 19,778,624	
13	Cash Working Capital	\$ 648,000	\$ (1,086,738)	\$ (438,738)	
14	Subtotal	\$ 120,936,000	\$ (1,673,902)	\$ 119,262,098	
<u>Other Rate Base Items</u>					
15	Materials and Supplies	\$ 150,000	\$ -	\$ 150,000	
16	Fuel Inventory	\$ 2,098,000	\$ -	\$ 2,098,000	
17	Non-Plant Assets & Liabilities	\$ 1,463,000	\$ -	\$ 1,463,000	
18	Customer Advances	\$ (1,340,000)	\$ -	\$ (1,340,000)	
19	Customer Deposits	\$ (42,000)	\$ -	\$ (42,000)	
20	Prepays and Other	\$ 523,000	\$ -	\$ 523,000	
21	Regulatory Amortization - ITT/ADIT ARAM	\$ 440,000	\$ (23,000)	\$ 417,000	WP A15
22	Total Other Rate Base Items	\$ 3,292,000	\$ (23,000)	\$ 3,269,000	NDPSC 1-32
23	Total Average Rate Base	\$ 124,228,000	\$ (1,696,902)	\$ 122,531,098	

(1) Company Exhibit BCH-1 Schedule 15

differences due to rounding

OPERATING INCOME STATEMENT

		(1)				Present Rates			
		Company		Company		ND PSC			
		Present Rates	Adjustments	Proposed Rates	Adjustments	Advocacy Staff	References		
Operating Revenues									
1	Retail Revenues	\$ 67,303,000	\$ 7,059,000	\$ 74,362,000	\$ -	\$ 67,302,687			
2	Interdepartmental	\$ -		\$ -	\$ -	\$ -			
3	Other Operating	\$ 550,000	\$ -	\$ 550,000	\$ -	\$ 550,384			
4	Total Operating Revenues	\$ 67,853,000	\$ 7,059,000	\$ 74,912,000	\$ -	\$ 67,853,071		DM-9	
Operating Expenses									
5	Purchased Gas	\$ 43,934,000		\$ 43,934,000	\$ -	\$ 43,934,429		DM-12	
6	Gas Production & Storage	\$ 635,000		\$ 635,000	\$ -	\$ 635,473		DM-13	
7	Gas Transmission	\$ 387,000		\$ 387,000	\$ (44,477)	\$ 342,523		DM-14	
8	Gas Distribution	\$ 5,129,000		\$ 5,129,000	\$ (1,146,821)	\$ 3,982,179		DM-15	
9	Customer Accounting	\$ 1,613,000		\$ 1,613,000		\$ 1,311,454		DM-16	
10	Customer Service & Other	\$ 149,000		\$ 149,000	\$ 10,771	\$ 159,771		DM-17	
11	Sales, Econ Development & Other	\$ 10,000		\$ 10,000	\$ (7,645)	\$ 2,355		DM-18	
12	Administrative & General	\$ 2,508,000		\$ 2,508,000		\$ 2,471,170		DM-19	
	Vacancy Rate Adjustment				\$ (173,413)	\$ (173,413)		1-34/20/17	
13	Total Operating Expenses	\$ 54,365,000	\$ -	\$ 54,365,000	\$ (1,699,058)	\$ 52,665,942			
14	Depreciation Expense	\$ 6,892,000	\$ -	\$ 6,892,000	\$ (16,873)	\$ 6,875,127		DM-20	
15	Amortization Expense	\$ 440,000	\$ -	\$ 440,000	\$ (166,994)	\$ 273,006		DM-21	
16	Taxes Other Than Income	\$ 2,401,000		\$ 2,401,000	\$ (341,453)	\$ 2,059,547		DM-22	
17	State Income Taxes	\$ (29,000)	\$ 304,243	\$ 275,243	\$ -	\$ (29,000)		DM-23	
18	Federal Income Taxes	\$ (135,000)	\$ 1,418,499	\$ 1,283,499	\$ -	\$ (135,000)		DM-23	
19	Total Taxes	\$ 2,237,000	\$ 1,722,742	\$ 3,959,742	\$ (341,453)	\$ 1,895,547			
20	Total Expenses	\$ 63,934,000	\$ 1,722,742	\$ 65,656,742	\$ (2,224,378)	\$ 61,709,622			
21	AFUDC	\$ -	\$ -	\$ -	\$ -	\$ -			
22	Total Operating Income	\$ 3,919,000	\$ 5,336,258	\$ 9,255,258	\$ 2,224,449	\$ 6,143,449			
23	Rate Base	\$ 124,228,000		\$ 124,228,000		\$ 122,531,098			
24	Rate of Return	3.155%		7.4502%		6.86%			
				\$ 9,255,258		\$ 8,403,988			
(1)	Company Exhibit BCH-1 Schedule 11								

differences due to rounding

GAS PLANT IN SERVICE

		(1)						
		Company		Company		ND PSC		
		Proposed	Unadj.	Proposed	Adj.	Advocacy	Staff	References
			Adjustments		Adjustments			
1	Gas Manufactured Plant	\$ 5,340,000	\$ -	\$ 5,340,000		\$ 5,340,000		
2	Gas Storage	\$ 9,341,000	\$ -	\$ 9,341,000		\$ 9,341,000		
3	Gas Transmission	\$ 3,909,000	\$ -	\$ 3,909,000		\$ 3,909,000		
4	Gas Distribution	\$ 181,046,000	\$ -	\$ 181,046,000	\$ (607,617)	\$ 180,438,383		ND PSC 1-46/49
5	General	\$ 11,871,000	\$ -	\$ 11,871,000		\$ 11,871,000		ND PSC 4-7/4-9
6	Common	\$ 11,348,000	\$ -	\$ 11,348,000		\$ 11,348,000		
7	Total Gas Plant In Service	\$ 222,855,000	\$ -	\$ 222,855,000	\$ (607,617)	\$ 222,247,383		ND PSC 1-44/45

(1) Company Exhibit BCH-1 Schedule 5

Meter Installation costs - outside \$3,500 x 111 - \$388,500 1-46 (relocation) 1-46
 Meter exchange costs \$453 X 12,525 = \$5,673,825 1-47
 Cost to exchange a module \$72 x 12,525 = \$901,800 commencing in 2023 1-48
 Fargo Project located in Gas Distribution
 Capital Additions 1-55 and 1-56
 AGIS adjustment 1-62
 Wescott - Spring of 2022, Sibley - Maplewood and Delta V

ACCUMULATED DEPRECIATION

	(1)		Company Proposed	Adjustments	ND PSC Advocacy Staff	References
	Company Unadjusted	Adjustments				
Gas Manufactured Plant	\$ 2,420,000	\$ (45,000)	\$ 2,375,000	\$ -	\$ 2,375,000	WP A8
Gas Storage	\$ 8,010,000	\$ 29,000	\$ 8,039,000	\$ -	\$ 8,039,000	WP A8
Gas Transmission	\$ 1,683,000	\$ 3,000	\$ 1,686,000	\$ -	\$ 1,686,000	WP A9
Gas Distribution	\$ 59,581,000	\$ 50,000	\$ 59,631,000	\$ (16,078)	\$ 59,614,922	WP A9
General	\$ 5,559,000	\$ 47,000	\$ 5,606,000	\$ -	\$ 5,606,000	WP A9
Common	\$ 5,619,000	\$ 17,000	\$ 5,636,000	\$ -	\$ 5,636,000	WP A9
Total Accumulated Depreciation	\$ 82,872,000	\$ 101,000	\$ 82,973,000	\$ (16,078)	\$ 82,956,922	

(1) Company Exhibit BCH-1 Schedule 5

ACCUMULATED DEFERRED INCOME TAXES

		(1)						
		Company		Company		ND PSC		
		Unadjusted	Adjustments	Proposed	Adjustments	Advocacy Staff	References	
1	Production	\$ (77,000)	\$ 12,000	\$ (65,000)	\$ -	\$ (65,000)	WP A8	
2	Transmission	\$ 718,000	\$ (1,000)	\$ 717,000	\$ -	\$ 717,000	WP A9	
3	Distribution	\$ 17,469,000	\$ (14,000)	\$ 17,455,000	\$ -	\$ 17,455,000	WP A9	
4	Gas Storage	\$ (416,000)	\$ (8,000)	\$ (424,000)	\$ (3,376)	\$ (427,376)	WP A8	
5	General	\$ 1,266,000	\$ (19,000)	\$ 1,247,000	\$ -	\$ 1,247,000	WP A9	
6	Common	\$ 625,000	\$ 1,000	\$ 626,000	\$ -	\$ 626,000	WP A9	
7	Net Operating Loss	\$ (93,000)	\$ -	\$ (93,000)	\$ -	\$ (93,000)		
8	Non-Plant Related	\$ 319,000	\$ -	\$ 319,000	\$ -	\$ 319,000		
9	Total Accumulated Deferred Income Taxes	\$ 19,811,000	\$ (29,000)	\$ 19,782,000	\$ (3,376)	\$ 19,778,624		

(1) Company Exhibit BCH-1 Schedule 15

CASH WORKING CAPITAL		(1)				ND PSC		
	Lead/Lag Days	Company Dollars	Dollar x Days	Adjustments	Advocacy Staff	References		
1	Fuel Expenses	39.09119	\$ 14,442,000	\$ 564,554,966	\$ 1,152,877,375	\$ 1,717,432,341	4-3	
	Labor							
2	Regular Payroll	11.890587	\$ 3,409,000	\$ 40,535,011	\$ (173,413)	\$ 38,473,031	DM-4	
3	Incentive	248.81	\$ 37,000	\$ 9,205,970	\$ (28,039)	\$ 2,229,586		
4	Pension & Benefits	37.23	\$ 647,000	\$ 24,087,810	\$ -	\$ 24,087,810		
			\$ 4,093,000	\$ 73,828,791	\$ (9,038,364)	\$ 64,790,427		
5	All Other Operating Expenses	22.73988	\$ 37,080,000	\$ 843,194,750		\$ 202,496,941	4-3	
6	Property Taxes	357.9199	\$ 1,587,000	\$ 568,018,881		\$ 450,486,576		
7	Employer's Payroll Taxes	31.6197	\$ 263,000	\$ 8,315,981		\$ 7,902,041		
8	Gross Earnings Tax	38.8962	\$ 1,214,000	\$ 47,219,987		\$ 47,219,987		
9	Federal Income Taxes	37.005	\$ (386,000)	\$ (14,283,930)		\$ (4,995,675)		
10	State Income Taxes	36.9156	\$ (83,000)	\$ (3,063,995)		\$ (1,070,552)		
			\$ 39,675,000	\$ 1,449,401,675		\$ 702,039,317		
11	Total		\$ 58,210,000	\$ 2,087,785,432		\$ 2,484,262,086		
12	Net Annual Expense (365)			\$ 5,719,960		\$ 6,806,197		
13	Revenues	40.2998	\$ 67,303,000	\$ 2,712,297,439		\$ 2,712,284,826		
14	Late Payment		\$ 155,000	\$ -		\$ -		
15	Miscellaneous Services	40.389	\$ 118,000	\$ 4,765,902		\$ 4,765,902		
16	Rentals	-50.009	\$ 211,000	\$ (10,551,899)		\$ (10,551,899)		
17	Total		\$ 67,787,000	\$ 2,706,511,442		\$ 2,706,498,829		
18	Net Annual Amount (365)			\$ 7,415,100		\$ 7,415,065		
19	Expense/Revenue Factor			85.87%		85.87%		
20	Allocated Revenue			\$ 6,367,489		\$ 6,367,459		
21	Net Cash Working Capital			\$ 647,529		\$ (438,738)		

(1) Company Exhibit BCH-1 Schedule 8

OPERATING REVENUES

		(1)		ND PSC		
		Company	Adjustments	Advocacy Staff	References	
		Proposed				
1	Residential Service	\$ 26,797,199	\$ -	\$ 26,797,199		
2	Commerical/Industrial	\$ 31,901,891	\$ -	\$ 31,901,891		
3	Small Interruptible Service	\$ 2,194,889	\$ -	\$ 2,194,889		
4	Large Interruptible Service	\$ 6,408,708	\$ -	\$ 6,408,708		
5	Interruptible	\$ -	\$ -	\$ -		
6	Firm Transportation Service	\$ -	\$ -	\$ -		
7	Total Present Rate Revenues	\$ 67,302,687	\$ -	\$ 67,302,687		
8	Other Gas Revenues	\$ 550,384	\$ -	\$ 550,384		1-33
9	Total Operating Revenues	\$ 67,853,071	\$ -	\$ 67,853,071		

(1) Company WP R2 Present Revenues
 Differences due to rounding

**OPERATION & MAINTENANCE
 EXPENSES - WORKSHEET**

Three-Year Normalize Non-Labor		(1) Company Proposed		Adjustments	ND PSC Advocacy Staff	References
1	Purchased Gas Expense	\$	43,934,429	\$ -	\$ 43,934,429	DM-12
2	Gas Production & Storage	\$	289,489	\$ -	\$ 289,489	DM-13
3	Gas Transmission	\$	304,359	\$ (44,169)	\$ 260,190	DM-14
4	Gas Distribution	\$	3,278,109	\$ (901,253)	\$ 2,376,856	DM-15
5	Customer Accounting	\$	1,217,726	\$ (301,166)	\$ 916,560	DM-16
6	Customer Service & Information	\$	140,217	\$ 11,853	\$ 152,070	DM-17
7	Sales, Econ Develop & Other	\$	8,872	\$ -	\$ 8,872	DM-18
8	Administrative & General	\$	1,099,071	\$ -	\$ 1,099,071	DM-19
9	Total	\$	50,272,272	\$ (1,234,735)	\$ 49,037,537	

(1) Company WP O2-3 Jurisdictional Alloc.
 Differences due to rounding

check for vacancy rate - 1-17 and 1-15
 check for hires in 1-19 - trade secret for salaries
 review 1-34 without labor

PURCHASED GAS

	(1) Company Proposed	Adjustments	ND PSC Advocacy Staff	References
1 Unadjusted Balance	\$ 43,934,429		\$ 43,934,429	
2 Adjustments	\$ -		\$ -	
3 Precedential Adjustments	\$ -		\$ -	
4 Adjusted Balance	\$ 43,934,429	\$ -	\$ 43,934,429	

(1) Company Schedule BCH-1 Schedule 6
 Company WP O2-3 Jurisdictional Allocation

GAS PRODUCTION & STORAGE

	(1) Company Proposed	Adjustments	ND PSC Advocacy Staff	References
1 Unadjusted Balance	\$ 635,473		\$ 635,473	
2 Adjustments	\$ -	\$ -	\$ -	ND PSC 4-12
3 Precedential Adjustments	\$ -	\$ -	\$ -	
4 Adjusted Balance	\$ 635,473		\$ 635,473	ND PSC 1-51

(1) Company Exhibit BCH-1 Schedule 6
 Company WP O2-3 Jurisdictional Allocation
 Wescott, Maplewood & Sibley Plants

GAS TRANSMISSION

		(1)			
		Company		ND PSC	
		Proposed	Adjustments	Advocacy Staff	References
1	Unadjusted Balance	\$ 386,692		\$ 386,692	
2	Adjustments - three year average	\$ -	\$ (44,169)	\$ (44,169)	ND PSC 1-34
	Damage Prevention Program	\$ -	\$ -	\$ -	ND PSC 1-53
3	Precedential Adjustments	\$ -	\$ -	\$ -	
4	Adjusted Balance	\$ 386,692	\$ (44,169)	\$ 342,523	

(1) Company Exhibit BCH-1 Schedule 6
 Company WP O2-3 Jurisdictional Allocation

GAS DISTRIBUTION

		(1)			
		Company		ND PSC	
		Proposed	Adjustments	Advocacy Staff	References
Unadjusted Balance					
1	G Customer MNND Border	\$ 2,258,174	\$ (775,305)	\$ 1,482,869	ND PSC 4-13
2	G Customers	\$ 947,014	\$ 168,496	\$ 1,115,510	
3	G Direct MN	\$ -	\$ -	\$ -	
4	G Direct ND	\$ 1,924,193	\$ (294,443)	\$ 1,629,750	
5	Total Balance	\$ 5,129,381	\$ (901,252)	\$ 4,228,129	ND PSC 1-50
6	Damage Prevention Program	\$ -	\$ (245,950)	\$ (245,950)	ND PSC 1-53
7	Precedential Adjustments	\$ -	\$ -	\$ -	
8	Adjusted Balance	\$ 5,129,381	\$ (1,147,202)	\$ 3,982,179	

- (1) Company Exhibit BCH-1 Schedule 6
 Company WP O2-3 Jurisdictional Allocation
 Fargo Capacity Cost - O&M \$18,000 plus \$4,600

CUSTOMER ACCOUNTING

		(1)			
		Company		ND PSC	
		Proposed	Adjustments	Advocacy Staff	References
Unadjusted Balance					
1	G Bad Debts	\$ 280,729	\$ 4,204	\$ 284,933	ND PSC 4-14
2	G Customers	\$ 932,545	\$ (191,159)	\$ 741,386	
3	G Direct MN	\$ -	\$ -	\$ -	
4	G Direct ND	\$ 399,447	\$ (114,312)	\$ 285,135	
5	Total Balance	\$ 1,612,721	\$ (301,267)	\$ 1,311,454	
6	Adjustments	\$ -	\$ -	\$ -	
7	Precedential Adjustments	\$ -	\$ -	\$ -	
8	Adjusted Balance	\$ 1,612,721	\$ (301,267)	\$ 1,311,454	

- (1) Company Exhibit BCH-1 Schedule 6
 Company WP O2-3 Jurisdictional Allocation
 Meter reading costs - 1-48

CUSTOMER SERVICE & INFORMATION

		(1)		ND PSC		
		Company	Adjustments	Advocacy Staff	References	
		Proposed				
Unadjusted Balance						
1	G Customers	\$ 51,713		\$ 51,713	ND PSC 1-34	
2	G Direct ND	\$ 97,676		\$ 97,676		
3	Advertising	\$ 40,000		\$ 40,000		
4	Total Unadjusted Balance	\$ 189,389	\$ -	\$ 189,389		
Adjustments						
5	Precedential Adjustments	\$ -	\$ 11,853	\$ 11,853	DM-10	
6	Adjusted Balance	\$ (40,000)	\$ (1,471)	\$ (41,471)	WP A1 Adv	ND-PSC 1-39

(1) Company Exhibit BCH-1 Schedule 6
 Company WP O2-3 Jurisdictional Allocation

SALES & ECONOMIC DEVELOPMENT

	(1) Company Proposed	Adjustments	ND PSC Advocacy Staff	References
Unadjusted Balance				
G Customers	\$ 2,355		\$ 2,355	
Total Unadjusted Balance	\$ 2,355	\$ -	\$ 2,355	
Adjustments	\$ -	\$ -	\$ -	ND PSC 1-34 WP A11 Econ.
Precedential Adjustments	\$ 7,382	\$ (7,382)	\$ -	Donations 1-41
Adjusted Balance	\$ 9,737	\$ (7,382)	\$ 2,355	

- (1) Company Exhibit BCH-1 Schedule 6
 Company WP O2-3 Jurisdictional Allocation

ADMINISTRATIVE & GENERAL

		(1)				
		Company		ND PSC		
		Proposed	Adjustments	Advocacy Staff		References
Unadjusted Balance						
1	G Customers MNND Border	\$ 226,813	\$ -	\$ 226,813		ND PSC 1-34
2	G Customers MNND Border	\$ 2,222,388	\$ -	\$ 2,222,388		
3	G Direct ND	\$ 58,455	\$ -	\$ 58,455		
4	Other	\$ 130,846	\$ -	\$ 130,846		
5	Total Unadjusted Balance	\$ 2,638,502	\$ -	\$ 2,638,502		
6	Adjustments - Other	\$ -	\$ -	\$ -		ND PSC 1-34 1-25/26
Precedential Adjustments:						
7	Advertising	\$ (28,856)	\$ -	\$ (28,856)		WP A1 Adv. 1-39
8	Customer Deposits	\$ 676	\$ -	\$ 676		WP A3
9	Incentive Pay	\$ (17,013)	\$ -	\$ (17,013)		WP A4
10	Incentive Pay LT	\$ (97,348)	\$ -	\$ (97,348)		WP A5
11	SERP	\$ (3,027)	\$ -	\$ (3,027)		WP A6
12	Total Precedential Adjustments	\$ (145,568)	\$ -	\$ (145,568)		
RM Adjustments						
13	Aviation (100%)	\$ (22,003)	\$ -	\$ (22,003)		WP A7
14	Chamber of Commerce	\$ 2,221	\$ (2,221)	\$ -		WP A10 - 1-40
15	Economic Develop Donations	\$ 6,226	\$ (6,226)	\$ -		WP A12 1-42
16	Incentive Pay - Environmental LTI	\$ 17,060	\$ (17,060)	\$ -		WP A13
17	Incentive Pay - Time Based LTI	\$ 10,979	\$ (10,979)	\$ -		WP A14
18	Total RM Adjustments	\$ 14,483	\$ (36,486)	\$ (22,003)		
19	Adjusted Balance	\$ 2,507,417		\$ 2,470,931		
20	rounding	\$ 239		\$ 239		
21	Total	\$ 2,507,656	\$ (36,486)	\$ 2,471,170		

- (1) Company Exhibit BCH-1 Schedule 6
 Company O2-3 Jurisdictional Allocation
 Company Exhibit BCH-1 Schedule 4

Review data responses to 1-6, 1-13, 1-14, 1-15, 1-16, 1-17
 Confirm total Gas Employees and the allocate employees who left

DEPRECIATION EXPENSE

		(1)		ND PSC		
		Company	Adjustments	Advocacy Staff	References	
		Proposed				
1	Unadjusted Balance	\$ 6,845,000	\$ (16,078)	\$ 6,828,922		1-43/4-9
Remaining Life						
2	Gas Manufactured Production Plant	\$ (90,872)	\$ -	\$ (90,872)		WP A8
3	Gas Other Storage Plant	\$ 58,954	\$ -	\$ 58,954		WP A8
4	Total Remaining Life	\$ (31,918)	\$ -	\$ (31,918)		
Depreciation Study						
5	Gas Distribution - Composite 2.646%	\$ 33,481	\$ -	\$ 33,481		WP A9
6	Gas Transmission - Composite 1.76%	\$ 1,767	\$ -	\$ 1,767		WP A9
7	Common-General - AGIS - 21.68%	\$ 17,742	\$ -	\$ 17,742		WP A9
8	General	\$ 27,897	\$ -	\$ 27,897		WP A9
9	Common-Intangible	\$ (6,212)	\$ -	\$ (6,212)		WP A9
10	Intangible	\$ 3,448	\$ -	\$ 3,448		WP A9
11	Total Depreciation Study	\$ 78,123	\$ -	\$ 78,123		
12	Adjusted Balance	\$ 6,891,205	\$ (16,078)	\$ 6,875,127		

(1) Company Exhibit BCH-1 Schedule 6
 Fargo Project located in Gas Distribution
 refer to 1-43, updated in Company
 Refer to 1-61/63

AMORTIZATION EXPENSE

	(1) Company Proposed	Adjustments	ND PSC Advocacy Staff	References
Unadjusted Balance	\$ -			
(2) Income Tax Tracker	\$ 9,317	\$ (3,727)	\$ 5,590	WP A15
NOL Tax Reform ADIT ARAM	\$ 22,547	\$ -	\$ 22,547	WP A16
(3) Rate Case Expense Amortization	\$ 408,115	\$ (163,246)	\$ 244,869	WP A17
Adjusted Balance	\$ 439,979	\$ (166,973)	\$ 273,006	

(1) Company Exhibit BCH-1 Schedule 6

Refer to 1-43 - updated in Company Rebuttal

- (2) Income Tax Tracker amortized over 5 years
- (3) Rate Case Expense amortized over 5 years

TAXES OTHER THAN INCOME				
	(1)			
	Company		ND PSC	
	Proposed	Adjustments	Advocacy Staff	References
Property Taxes	\$ 1,587,442	\$ (328,818)	\$ 1,258,624	1-24
Payroll Taxes	\$ 262,844	\$ (12,935)	\$ 249,909	1-34
Unadjusted Deferred Income Taxes / ITC	\$ 564,000	\$ -	\$ 564,000	
Depreciation Study - Remaining Life				
Gas Manufactured Plant	\$ 25,543	\$ -	\$ 25,543	
Gas Other Storage Plant	\$ (16,571)	\$ -	\$ (16,571)	
Total	\$ 8,972	\$ -	\$ 8,972	WP A8
Depreciation Study - TD&G - 28.11%				
Gas Distribution	\$ (9,410)	\$ -	\$ (9,410)	
Gas Transmission	\$ (497)	\$ -	\$ (497)	
Common-General	\$ (4,987)	\$ -	\$ (4,987)	
General	\$ (7,841)	\$ -	\$ (7,841)	
Common-Intangible	\$ 1,746	\$ -	\$ 1,746	
Intangible Plant	\$ (969)	\$ -	\$ (969)	
Total	\$ (21,958)	\$ -	\$ (21,958)	WP A9
Adjusted Deferred Income Taxes/ITC	\$ 551,014	\$ -	\$ 551,014	
Total Taxes Other Than Income	\$ 2,401,300	\$ (341,753)	\$ 2,059,547	

(1) Company Exhibit BCH-1 Schedule 6

STATE INCOME TAXES
FEDERAL INCOME TAXES

	(1)			
	Company	Adjustments	ND PSC	References
	Proposed		Advocacy Staff	
State Income Taxes				
Current - 4.31%	\$ (29,000)	\$ -	\$ (29,000)	NDPSC 1-38
Proposed Revenue Requirement	\$ 7,059,000		\$ 2,990,332	
Proposed State Income Taxes	\$ 304,243		\$ 128,883	
Proposed Balance	\$ 275,243		\$ 99,883	
Federal Income Taxes				
Current - 21%	\$ (135,000)	\$ -	\$ (135,000)	NDPSC 1-38
Proposed Revenue Requirement	\$ 7,059,000		\$ 2,990,332	
Proposed Federal Income Taxes	\$ 1,418,499		\$ 600,904	
Proposed Balance	\$ 1,283,499		\$ 465,904	
Check total	\$ 1,558,742		\$ 565,788	

(1) Company Exhibit BCH-1 Schedule 3A
 Differences due to rounding

