

Rebuttal Testimony and Schedules
Benjamin C. Halama

Before the North Dakota Public Service Commission
State of North Dakota

In the Matter of the Application of Northern States Power Company
for Authority to Increase Rates for Electric Service in North Dakota

Case No. PU-20-441
Exhibit___(BCH-3)

OVERALL REVENUE REQUIREMENTS

**Rate Base
Income Statement**

June 1, 2021

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I. INTRODUCTION

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- Q. PLEASE STATE YOUR NAME AND OCCUPATION.
- A. My name is Benjamin C. Halama. I am Manager of Revenue Analysis for Xcel Energy Services Inc.
- Q. HAVE YOU PREVIOUSLY PROVIDED TESTIMONY IN THIS PROCEEDING?
- A. Yes. I filed Direct Testimony on behalf of Northern States Power Company, a Minnesota corporation (Xcel Energy, NSP or Company) supporting the Company's financial data and request for a general and interim rate increase, specifically:
- the overall retail revenue requirement of \$225.613 million and revenue deficiency of \$19.197 million, determined by the 2021 test year cost of service study (COSS); and
 - the interim increase of \$13.328 million as discussed in our Petition for Interim Rates.
- Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?
- A. My Rebuttal Testimony and supporting schedules address issues raised by the Commission Advocacy Staff witnesses. Specifically, I respond to the financial adjustments suggested by Mr. Dante Mugrace. I also update our financial statements to reflect those adjustments recommended or accepted by the Company. My Rebuttal Testimony supports a North Dakota jurisdictional electric utility operation overall retail revenue requirement of \$224.297 million and revenue deficiency of \$17.880 million.

1 Q. WERE THE SCHEDULES PRESENTED WITH YOUR REBUTTAL TESTIMONY
2 PREPARED BY YOU OR UNDER YOUR SUPERVISION?

3 A. Yes, they were.
4

5 **II. SUMMARY AND ORGANIZATION**
6

7 Q. PLEASE PROVIDE A SUMMARY OF YOUR REBUTTAL TESTIMONY

8 A. My Rebuttal Testimony will present the Company's proposed rebuttal revenue
9 requirement of \$224.297 million for a deficiency of \$17.880 million. I will also
10 focus on the Direct Testimony of Mr. Mugrace with respect to the overall
11 revenue requirement, the test-year revenue deficiency, and jurisdictional cost
12 of service. I present an issue-by-issue analysis, discussion, and supporting
13 schedules that produce an overall revenue requirement and revenue deficiency
14 for the 2021 North Dakota jurisdiction electric utility.
15

16 In my testimony, I also correct Mr. Dante Mugrace's proposed adjustment of
17 \$15.606 million to \$16.636 million and revise his proposed revenue deficiency
18 from \$3.591 million to \$2.561 million. Mr. Mugrace corrected his proposed
19 \$3.591 million revenue deficiency in a supplemental response to XE-1-001 to
20 \$2.562 million.
21

22 The overall cost of service is presented in Exhibit____(BCH-3), Schedule 1, 2021
23 Test Year Rebuttal Cost of Service Study. Comparisons between the detailed
24 Income Statement in our revised March 26, 2021 Notice of Change in Rates and
25 the Company's proposed Rebuttal request are included in Exhibit____(BCH-3),
26 Schedule 2. Each of the Company's proposed Rebuttal adjustments is included
27 in Exhibit____(BCH-3), Schedule 3 and Exhibit____(BCH-3), Schedule 4, which

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1 bridges our original Application to our Rebuttal request and shows the resulting
2 impact on rate base and operating income, respectively. My calculation of Mr.
3 Mugrace's proposal are provided in BCH-3 Schedule 5, 2021 Mugrace
4 Corrected Bridge Schedule.

5
6 Q. DO YOU CONCUR WITH MR. MUGRACE'S CORRECTED REVENUE DEFICIENCY
7 PROVIDED IN HIS SUPPLEMENTAL RESPONSE TO DATA REQUEST XE-1-001?

8 A. Mr. Mugrace's corrected revenue deficiency and my calculation of the revenue
9 deficiency are within \$589.00 of each other and I concur that the correct
10 calculation of Mr. Mugrace's proposed adjustments should result in a revenue
11 deficiency of approximately \$2.561 million. I, however, could not duplicate
12 Mr. Mugrace's results given the information he provided in his supplement to
13 Data Request XE-1-001.

14
15 Q. HOW HAVE YOU ORGANIZED YOUR REBUTTAL TESTIMONY?

16 A. My Rebuttal Testimony is organized as follows:

17 I. Introduction

18 II. Summary and Organization

19 III. Advocacy Staff Adjustments Accepted

20 A. AGIS Deferral

21 IV. Advocacy Staff Adjustments Opposed

22 A. Historical Normalization

23 B. Sherco 1&2 Depreciation

24 C. PI EPU Project

25 D. Depreciation Study: TD&G

26 E. 187 Solar

27 F. Aviation

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- 1 G. Donations and Chamber of Commerce Dues
- 2 H. Economic Development Donations
- 3 I. Incentive Compensation
- 4 J. Income Tax Tracker
- 5 K. Rate Case Expense
- 6 L. Jeffers Wind and Community Wind North
- 7 M. Mankato Energy Center II PPA
- 8 N. ND RTF Amortization
- 9 O. Non-Plant and Other Rate Base
- 10 P. Advertising, Association Dues, and Customer Deposits
- 11 Q. Payroll Tax
- 12 V. Company's Proposed Adjustments
 - 13 A. FERC Audit
 - 14 B. RER PTC Amortization
- 15 VI. Secondary Calculations
 - 16 A. ADIT Prorate – IRS Required
 - 17 B. Cash Working Capital
 - 18 C. Deferred Tax Credits
 - 19 D. Change in Cost of Capital
 - 20 E. Federal and State Income Taxes
 - 21 F. Interest Synchronization
- 22 VII. Conclusion

23

24 **III. ADVOCACY STAFF ADJUSTMENTS ACCEPTED**

25 **A. AGIS Deferral**

26 Q. PLEASE DESCRIBE MR. MUGRACE'S PROPOSAL WITH RESPECT TO AGIS.

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1 A. Mr. Mugrace proposed that the Company should request deferral of the
2 Company's AGIS initiative investments, where the associated costs would be
3 booked in a regulatory asset account, and request recovery at a time when
4 these costs become known and measurable. He states later in his testimony
5 that, since he proposed removal of the investment portion from the plant
6 balance, the expense portion should not be recovered in this proceeding.

7

8 Q. DOES THE COMPANY AGREE WITH MR. MUGRACE'S RECOMMENDATION?

9 A. Yes. As Company Witness Mr. Mark Moeller discusses in his Rebuttal
10 Testimony, these investments are used and useful in the provision of electric
11 service. However, we understand the desire to defer the capital and O&M
12 expense until all the foundational elements of the AGIS initiative have been
13 placed into service (i.e., when all meters have been installed). At that time, the
14 Company would propose to recover those costs in the next rate case filing.
15 To that end, the Company is requesting that all AGIS costs – capital and
16 O&M – incurred by the Company be placed in a deferral and treated as if all
17 these AGIS costs were Construction Work in Process (CWIP). Should this
18 proposal be accepted by the Commission, the Company will submit a
19 compliance filing detailing how it will create and adjust this deferral to align
20 the Company's in-servicing of the AGIS capital, Company expenditures of
21 O&M related to AGIS, and the accrual of an allowance for funds used during
22 the deferral (as the Company would accrue allowance for funds used during
23 construction for projects in CWIP). This adjustment results in a \$1.605
24 million dollar reduction to the 2021 test year revenue requirements as shown
25 in Rebuttal Schedule 4, 2021 Test Year Rebuttal Bridge Schedule – Income
26 Statement, page 1, row 39, columns 2 and 3.

27

1 **IV. ADVOCACY STAFF ADJUSTMENTS OPPOSED**

2 **A. Historical Normalization**

3 Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR REBUTTAL TESTIMONY?

4 A. In this section, I respond to Mr. Mugrace’s proposed normalization of certain
5 O&M, labor, and other expenses by using historical averages to make
6 adjustments to certain costs. I demonstrate that Mr. Mugrace’s proposed
7 normalization is not appropriate; therefore, I have not included these
8 adjustments in my Rebuttal 2021 test year COSS.

9
10 Q. WHAT TEST YEAR DID THE COMPANY SELECT FOR DETERMINING THE
11 REVENUE REQUIREMENT?

12 A. We selected a projected future test year of calendar year 2021.

13
14 Q. WHY IS A FUTURE TEST YEAR APPROPRIATE?

15 A. The purpose of a test period is to establish the level of revenues and expenses
16 “representative of those that will be experienced during the time the rates are
17 likely to remain in effect.”¹ The Commission has expressly found forecasted
18 test years to be an appropriate method of matching rates to the period during
19 which the rates will be in effect:

20 Because the Commission sets rates for the future, it is appropriate to
21 examine a period during which those rates will be in effect. The
22 utilization of a forecast test year adjusted for known and measurable
23 changes permits an accurate basis for setting rates for the future and
24 contributes to rate stability.²

¹ NARUC Electric Utility Cost Allocation Manual, January 1992 at 24.

² *In re Otter Tail Power Co.*, North Dakota Public Service Commission Case No. 10,334, Order (April 19, 1983); see also *In re Montana Dakota Utilities Company*, Case No. 10,280, 46 P.U.R. 193 (April 12, 1982).

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1 Q. DID MR. MUGRACE ACCEPT THE USE OF A PROJECTED CALENDAR YEAR 2021
2 TEST YEAR?

3 A. Yes. At page 5 of his Direct Testimony, Mr. Mugrace accepts the Company's
4 proposed test year ending in December 31, 2021, with his proposed three-year
5 averaging adjustments.

6
7 Q. HOW DID THE COMPANY DEVELOP ITS FUTURE TEST YEAR?

8 A. The Company utilized its forecasted 2021 budget of revenues and expenses as
9 the basis of its 2021 test year. Use of the forecasted budget is consistent with
10 the Company's long-standing practice and is consistent with North Dakota
11 statute and Commission precedent.

12

13 *1. O&M Normalization*

14 Q. WHAT IS MR. MUGRACE PROPOSING THROUGH HIS O&M NORMALIZATION
15 ADJUSTMENT?

16 A. Mr. Mugrace proposed to adjust the Company's cost of service using a three-
17 year historical average to determine a portion of revenue and expense. Mr.
18 Mugrace recommends the removal of \$3.482 million in total O&M expenses
19 from the Company's cost of service based on his three-year averaging
20 approach.

21

22 Q. WHICH REVENUES AND EXPENSES DID MR. MUGRACE PROPOSE TO ADJUST?

23 A. Mr. Mugrace proposed to adjust the following FERC accounts:

- 24 • Power Production – Variable: O&M production expenses in FERC
25 accounts 500-559 that are generally variable in nature. Nuclear fuel end
26 of life expenses are recorded in this category.

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- 1 • Regional Markets: O&M expenses in FERC account 575 that can be
2 fixed or variable. Included in this group are expenses related to day-
3 ahead and real time market administration and market monitoring.
- 4 • Transmission: O&M expenses in FERC accounts 560-579. For example,
5 O&M related to overhead transmission line operation and maintenance,
6 MISO related expenses including self-funding costs, and maintenance of
7 station equipment.
- 8 • Customer Border Allocator in Distribution O&M: O&M expenses in
9 FERC accounts 580-599 that are that are assigned to jurisdiction based
10 on a regional customer allocator. A regional customer allocator reflects
11 the fact there are customers in both Minnesota and North Dakota that
12 are served by operations located at North Dakota service centers.
- 13 • Bad Debt expenses in Customer Accounting: Customer account expense
14 function represents common customer service administrative activities.
15 Bad debt expenses recorded as Customer Accounting in FERC 904.
- 16 • Customer Service and Information: O&M expenses recorded in FERC
17 accounts 908-910, including costs associated with informational and
18 instructional advertising.
- 19 • Administrative and General: O&M expenses recorded in FERC accounts
20 920-936, including pension and medical insurance costs, regulatory fees,
21 various insurance costs.

22
23 Q. DID MR. MUGRACE EXPLAIN WHY HE CHOSE THESE REVENUES AND EXPENSES
24 TO ADJUST?

25 A. Not in sufficient detail to justify his approach. Mr. Mugrace merely uses a
26 recurring justification that these costs and revenues can “fluctuate and vary
27 from year to year,” and in some cases the balances during the 2018-2020

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1 period appear to be “abnormal and irregular” compared to the Company’s
2 proposed 2021 test year. As a result, Mr. Mugrace argues that the use of a
3 three-year average provides a smoothing of the costs and revenues.³
4

5 Q. IS THE THREE-YEAR AVERAGE OF EXPENSES AND REVENUES SELECTIVELY
6 CHOSEN BY MR. MUGRACE REPRESENTATIVE OF THE COST OF SERVICE
7 DURING THE PERIOD RATES WILL BE IN EFFECT?

8 A. No. The Company’s forecasted test year incorporates factors that do not exist
9 in prior year historical data but are indicative of the costs that will exist in the
10 period rates will be in effect.
11

12 Q. CAN YOU PROVIDE AN EXAMPLE OF FACTORS THAT DO NOT EXIST IN PRIOR
13 YEARS THAT WILL EXIST IN THE PERIOD RATES WILL BE IN EFFECT?

14 A. Yes. A good example are changes in our expenses related to supporting
15 investments in new technology. Mr. Mugrace’s proposed normalization would
16 adjust out of the Company’s cost of service real increases in O&M expenses
17 for Application Development & Maintenance services, as well as increased
18 Software and Hardware licensing and maintenance. This was noted as a cost
19 driver in my Direct Testimony. Historical levels of costs in these areas do not
20 reflect upgrades and new technologies necessary to support the capital assets
21 built as a result of business demand. As the Company continues to invest in
22 technology – and incurs new and different costs – utilizing historic actuals
23 would not reflect the Company’s changed circumstances.
24

³ See e.g., Mugrace Direct at 28, discussing O&M expenses.

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1 Q. ARE THERE OTHER REASONS MR. MUGRACE'S APPROACH IN NORMALIZING
2 HISTORICAL COST FLUCTUATIONS IS INAPPROPRIATE FOR SETTING RATES?

3 A. Yes. In addition to the normalization approach mismatching costs to the
4 period rates are in effect, costs and expenses also fluctuate year-to-year for
5 valid reasons. However, the representative future test year should "even out"
6 and the various "ups" and "downs" of certain expenses should offset.
7 Consequently, just because actual past expenses fluctuate year-to-year, that is
8 not a valid reason to use averages of broad cost categories when setting rates.

9

10 Mr. Mugrace's approach is both too narrow and too broad. He is proposing
11 to normalize broad categories of O&M costs but does not capture the entire
12 cost of service so that ups and downs would "even out". He also did not
13 identify any particular cost centers that warranted further examination to
14 determine if they should be adjusted. Consequently, his approach will
15 necessarily produce arbitrary results based on a subjective analysis of accounts
16 that do nothing more than fluctuate.

17

18 Q. WOULD NORMALIZATION EVER BE APPROPRIATE?

19 A. Potentially. If the information presented to Advocacy Staff indicated that the
20 Company's forecasts for certain costs were generally inaccurate, then utilizing
21 historical actual amounts could be a reasonable basis to make targeted
22 adjustments to the cost of service. To the extent Mr. Mugrace had concerns
23 with the Company's forecasted amounts for certain expenses, he could have
24 proposed an adjustment for those. However, Mr. Mugrace did not question
25 the veracity of the Company's overall budget or explain why his adjustment
26 would be representative of the Company's actual cost of service.

27

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1 Q. DOES THE COMPANY'S BUDGETING PRODUCE ACCURATE FORECASTS?

2 A. Yes. When looked at from a total cost of service perspective, the Company's
3 budgets have, historically, been accurate on an overall basis. This
4 demonstrates that the selective adjustment of only certain costs that fluctuate
5 year-over-year does not lead to an accurate cost of service upon which to set
6 rates. Table 1 below, and Schedule 10 of my Direct Testimony, shows the
7 historical accuracy of the Company's budgeting for electric operations.

8

9

Table 1

10

NSPM Electric Utility Actual versus Budget O&M (\$millions)

11

Year	Budget Amount	Actual Amount	\$ Variance	% Variance
2019	\$1,101.2	\$1,109.5	\$8.3	0.7%
2018	\$1,117.2	\$1,115.4	(\$1.8)	(0.2%)
2017	\$1,119.7	\$1,113.5	(\$6.2)	(0.6%)
Three-Year Total	\$3,338.1	\$3,338.4	(\$0.3)	(0.0%)

15

16

17

18

18 Q. IS MR. MUGRACE'S APPROACH TO ANALYZING CERTAIN GROUPS OF FERC
19 ACCOUNTS TO DETERMINE IF THEY ARE IRREGULAR APPROPRIATE FOR
20 DETERMINING THE COMPANY'S REVENUE DEFICIENCY?

21

22

23

24

25

26

27

28

21 A. No. Mr. Mugrace's approach does not factor in that certain anomalous issues
22 can occur in a particular year which can lead to fluctuations in certain accounts
23 annually. Additionally, changes in accounting, law, or policy can also lead to
24 changes in certain costs not captured utilizing historical values. Consequently,
25 it is more appropriate to analyze the Company's future test year budget to
26 determine if it is reasonably representative of the Company's cost of service in
27 2021. Mr. Mugrace's normalization approach ignores these issues by assuming
28 that historical actuals are appropriate for setting rates using a future test year.

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1 Q. PLEASE PROVIDE AN EXAMPLE OF A HISTORICAL ANOMALY.

2 A. As I discussed in my Direct Testimony, the Company received an abnormal
3 distribution from its nuclear insurer, Nuclear Electric Insurance Limited
4 (NEIL), in 2019 of approximately \$0.700 million (ND allocated). This drove
5 down the Company's A&G expense in 2019. By incorporating this anomalous
6 decrease in the Company's A&G expense in his normalization proposal, Mr.
7 Mugrace is not considering that this type of distribution is unlikely to occur in
8 2021. I note that the Company does factor in, and budgets for, insurance
9 distributions to the extent they can be reasonably forecasted.

10

11 Q. CAN YOU PROVIDE AN EXAMPLE OF AN ACCOUNTING OR POLICY CHANGE?

12 A. Yes. Mr. Mugrace is proposing to normalize the Company's bad debt
13 expense. In 2018 the Company's bad debt expense was accounted for as part
14 of the customer allocator. However, in 2019, the Company's bad debt
15 expense was moved to a unique bad debt allocator based on revenues. This
16 means that the Company did incur North Dakota allocated bad debt, it was
17 just located elsewhere in the cost of service. Rather than question why the
18 Company's accounts showed no bad debt expense in 2018, Mr. Mugrace
19 merely included an amount of zero for 2018 in his three-year average.
20 Consequently, Mr. Mugrace is not actually capturing the Company's historical
21 bad debt expenses in the years he is using for his normalization nor is his
22 proposed normalized amount indicative of the Company's bad debt costs in
23 2021.

24

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1 Q. DO YOU HAVE OTHER CONCERNS WITH THE DATA SET MR. MUGRACE
2 UTILIZED FOR HIS NORMALIZATION ADJUSTMENT?

3 A. Yes. In addition to my concerns about which types of O&M costs he selected
4 to normalize, I am also concerned with his choices of 2018, 2019, and 2020 to
5 create his data set and his choice to utilize North Dakota jurisdictionally
6 allocated amounts in his normalization calculation.

7

8 Q. WHAT ARE YOUR CONCERNS WITH MR. MUGRACE'S SELECTION OF 2018, 2019,
9 AND 2020 AS THE THREE YEARS TO USE FOR HIS NORMALIZATION
10 ADJUSTMENT?

11 A. Mr. Mugrace's choice to use three years of historical data seems wholly
12 arbitrary and is not supported in his Direct Testimony. He gives no reason
13 why he wouldn't use the past five years, or the past eight years – the time since
14 the Company's last rate case – to perform his normalization analysis.
15 Compounding the arbitrary nature of his selection of 2018, 2019, and, 2020,
16 he proposed to normalize "other revenue" using a wholly different period of
17 2019, 2020, and the 2021 test year. Mr. Mugrace provides no support for his
18 selection of these different normalization periods and it calls into question the
19 analytical rigor of his proposed adjustment.

20

21 Q. WHAT ARE YOUR CONCERNS WITH MR. MUGRACE'S CHOICE TO UTILIZE COSTS
22 ALLOCATED TO THE NORTH DAKOTA JURISDICTION AS THE DATA SET FOR HIS
23 NORMALIZATION ADJUSTMENT?

24 A. The proposed historical costs, revenues, and allocators do not reflect the
25 costs, revenues, and allocators during the period rates will be in effect.

26

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1 Q. PLEASE EXPLAIN HOW THESE DATA SET CHOICES DO NOT LEAD TO JUST AND
2 REASONABLE RESULTS.

3 A. Not only is using a three-year average arbitrary, it also includes two years of
4 data that are not consistent with the projected test year.

5

6 In 2018, the 12 CP demand allocator dropped to a historically low level which
7 reduced the North Dakota portion of O&M expenses. By utilizing actual
8 costs allocated to North Dakota in his 2018 data set for the normalization
9 adjustment, Mr. Mugrace is not actually smoothing out fluctuations in costs,
10 but is, in fact, introducing additional complexity and “noise” into his
11 adjustment. Consequently, his normalization proposal is doing the opposite
12 of its intent to smooth out costs for setting rates.

13

14 Additionally, in 2020 the global pandemic resulted in overall impacts to how
15 we manage our operations. The Company necessarily had to manage the
16 impact of the pandemic on its operations as discussed in detail in Case No.
17 PU-20-192. An example of the impact of the pandemic to the Company’s
18 cost of service includes the fact that the Company’s MISO expenses were
19 abnormally low in 2020 in light of lower usage volumes of the transmission
20 system due to the COVID-19 pandemic. Due to these lower than normal
21 costs, Mr. Mugrace’s use of 2020 data in his normalization adjustment can lead
22 to understating the Company’s actual cost of service in 2021.

23

24 Q. WOULD A DIFFERENT DATA SET PRODUCE DIFFERENT RESULTS FOR MR.
25 MUGRACE’S NORMALIZATION ANALYSIS?

26 A. Yes. Demonstrating the arbitrary nature of Mr. Mugrace’s proposal, the
27 Company analyzed its overall O&M expenses, excluding fuel, going back to

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1 2016, which was the first year following the multi-year rate plan period from
2 the Company's last rate case. The Company's total O&M expense, excluding
3 fuel which is recovered through the Fuel Cost Rider (FCR), in this historical
4 period (2016 to 2020) grew at a compound annual growth rate (CAGR) of 0.8
5 percent. However, the CAGR over the four years Mr. Mugrace used for his
6 normalization adjustments is 3.0 percent. The CAGRs for different time
7 periods show the three-year period of 2018-2020 chosen by Mr. Mugrace for
8 his normalization adjustments is not only arbitrary but also does not lead to
9 reasonable results. As discussed above, two of the three years in that time
10 frame have anomalous issues. Based on my CAGR analysis, extending the
11 time period used in normalization dramatically changes the overall impact of
12 the application of a normalization adjustment. Simply, Mr. Mugrace's
13 proposed adjustment would be lower if he extended out his normalization
14 period to five years. This indicates that his normalization does not actually
15 lead to consistent results, his purported rationale for employing the tool. I
16 also note that my CAGR analysis indicates that the Company's long-term
17 CAGR for O&M is in line with normal inflationary measures, demonstrating
18 its prudence.

19
20 Q. IS MR. MUGRACE'S PROPOSAL CONSISTENT WITH NORTH DAKOTA STATUTORY
21 PROVISIONS?

22 A. I am not a lawyer, but I believe the answer is no. North Dakota Century Code
23 (N.D.C.C.) § 49-05-04.1 provides in part:

24 A public utility, at its option, may use any one of the following
25 twelve-month periods as its test year for rate filings with the
26 commission:

27 a. A historical test year, which may be either the latest twelve-
28 month period for which actual data is available at the time of
29 filing new schedules or the latest calendar or fiscal year for

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1 which actual data is available at the time of filing new
2 schedules.

3 b. A current test year, which is any consecutive twelve-month
4 period ending not later than twelve months after the date new
5 schedules are filed. A public utility selecting a current test
6 year also shall file data for the twelve-month period
7 immediately preceding the current test year selected and that
8 period is the “historical period” for the public utility.

9 c. A future test year, which is any consecutive twelve-month
10 period ending no later than twenty-four months after the date
11 new schedules are filed. A public utility selecting a future test
12 year must file data for the twelve consecutive months
13 immediately preceding the future test year and that period is
14 the “current period” for the public utility. (Emphasis added.)
15

16 Three relevant conclusions are apparent from a review of the above statute.
17 First, the Company has the right to select the test year. The Company has
18 selected a future 2021 test year. Second, even if Mr. Mugrace could propose
19 using a historical test year, it could not be based on a three-year average. A
20 historical test year must be based on a consecutive twelve-month period that is
21 no earlier than the latest period for which actual data is available, which in this
22 case would be 2019. Third, the future test year must also be a “consecutive
23 twelve-month period.” Mr. Mugrace’s proposal to selectively use a three-year
24 historical average for some revenues and expenses is inconsistent with the
25 requirement that a test year use a consecutive twelve-month period.
26

27 Q. DO YOU AGREE THAT O&M NORMALIZATION ADJUSTMENTS ARE
28 APPROPRIATE?

29 A. No. As discussed above, I believe the normalization adjustments proposed by
30 Mr. Mugrace are inappropriate for at least three reasons. First, adjusting sub-
31 sets of O&M to a normalized historical level does not allow for changes in
32 operations and expense types. Second, the Company doesn’t manage its

1 business at the jurisdictional allocator level, but rather as a holistic entity.
2 Third, the data does not support the need for normalization. For these
3 reasons, I believe the Commission should not adopt Mr. Mugrace's
4 recommended normalization adjustments.

5
6 2. *Labor Normalization and Secondary Normalization Adjustments*
7

8 Q. DID MR. MUGRACE PROPOSE ANY OTHER NORMALIZATION ADJUSTMENTS?

9 A. Yes. In addition to the O&M normalization adjustment I just discussed, Mr.
10 Mugrace proposed to normalize all of the Company's labor expenses by using
11 a simple average of labor expenses over the same three-year period of 2018-
12 2020. Using this methodology, Mr. Mugrace is proposing an adjustment of
13 \$2.087 million in addition to his O&M normalization discussed earlier.

14
15 Q. DO YOU AGREE WITH MR. MUGRACE'S PROPOSED LABOR NORMALIZATION
16 ADJUSTMENT?

17 A. No. For the same reasons I do not agree with Mr. Mugrace's proposed O&M
18 adjustment, I also disagree with his labor normalization adjustment. At base,
19 his labor normalization adjustment is arbitrary and not reflective of the
20 Company's actual cost of service in 2021.

21
22 Q. DO YOU HAVE OTHER CONCERN'S WITH MR. MUGRACE'S PROPOSED LABOR
23 NORMALIZATION ADJUSTMENT?

24 A. Yes. Mr. Mugrace's labor normalization adjustment: (1) creates duplicative
25 adjustments with his O&M normalization adjustment; and (2) does not factor
26 in the Company's increasing cost of labor.
27

1 Q. HOW IS MR. MUGRACE'S DUPLICATIVE?

2 A. In brief, labor is a sub-set of total O&M, and therefore some of the same
3 costs are being adjusted from the cost of service twice. Table 2 below provides
4 an example of the double normalization based on the Transmission O&M
5 function:

6 **Table 2**
7 **Transmission O&M Normalization Example**

8	9	10	11
Transmission O&M	2021 Test Year	Proposed Mugrace Adjustments	
Labor	1,201,224	(121,678)	
Labor – Benefits	76,038		
Non-Labor	<u>8,874,283</u>		
Total O&M Expense	10,151,545	(605,930)	
Total Proposed Adjustment - Transmission O&M		(727,608)	
Amount Double Normalized		(121,678)	

12
13
14
15
16
17 In normalizing both Transmission labor and total Transmission O&M
18 expense, Mr. Mugrace is removing \$0.122 million in O&M expense twice. In
19 total, I calculate \$2.463 million in duplicative adjustments proposed to the
20 Company's 2021 test year COSS. Exhibit__(BCH-3), Schedule 6, 2021
21 Mugrace Double Normalization, to my Rebuttal Testimony provides
22 additional information.

23
24 Q. DOES THIS DOUBLE NORMALIZATION EXIST IN OTHER ADJUSTMENTS?

25 A. Yes. In the adjustments to Employee Expense and Pension Non-Qualified
26 SERP, Mr. Mugrace is again using a three-year average to determine non-labor
27 benefits. As I explained previously, a three-year historical average is not an

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1 appropriate methodology for determining test year expenses. Non-labor is a
2 sub-set of total O&M expenses, so increasing O&M to reflect this
3 normalization is also a double adjustment of the same costs. As shown in
4 Schedule 6, I calculate a total of \$0.797 million in duplicative adjustments
5 increasing the 2021 test year COSS.

6
7 Q. WHAT OTHER CONCERNS DO YOU HAVE WITH MR. MUGRACE'S PROPOSED
8 LABOR NORMALIZATION ADJUSTMENT?

9 A. The issues we have identified with Mr. Mugrace's recommended labor
10 normalization clearly demonstrate the flaws in his overall normalization
11 methodology. Our annual labor budgeting process includes increases in labor
12 costs required by our labor contracts and for "merit increases" that are part of
13 our overall compensation package to non-bargaining employees. Mr.
14 Mugrace's normalization proposal adjusts these actual costs out of the
15 Company's cost of service. In addition, his normalization proposal adjusts out
16 increases to contract labor costs that are occurring from tight labor markets
17 and that even he admits are out of our control. These facts demonstrate the
18 inappropriate nature of Mr. Mugrace's proposed labor normalization
19 adjustment.

20
21 Q. WHAT ADJUSTMENT HAS MR. MUGRACE MADE WITH RESPECT TO OTHER
22 REVENUE?

23 A. Mr. Mugrace recommends an adjustment of \$0.310 million to other revenues,
24 based on his historical averaging approach. Mr. Mugrace argues that these
25 revenues, which relate to items such as late payment fees, returned checks,
26 service fees, etc. can fluctuate from year to year, thus his adjustment reflects a
27 normalization of these revenues using a three-year average.

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1

2 Q. DO YOU AGREE THAT THIS ADJUSTMENT IS APPROPRIATE?

3 A. No. For the reasons I disagree with the O&M normalization adjustments
4 above, I do not agree with this adjustment and have not reflected this decrease
5 in the 2021 test year COSS.

6

7 *3. Normalization Conclusion*

8

9 Q. WHAT IS THE PROPER CALCULATION OF MR. MUGRACE'S NORMALIZATION
10 ADJUSTMENTS?

11 A. Mr. Mugrace proposed \$3.482 million decrease in O&M normalization
12 adjustment; \$2.087 million decrease in labor normalization adjustment; and
13 \$0.797 million increase in other normalization adjustments for a grand total of
14 \$4.772 million. When corrected for duplicative adjustments, Mr. Mugrace's
15 actual normalization adjustment would be a \$3.106 million decrease inclusive
16 of these categories. My calculations are provided in BCH-3 Schedule 5, 2021
17 Mugrace Corrected Bridge Schedule and BCH-3 Schedule 6, Mugrace Double
18 Normalization.

19

20 Q. HAVE YOU INCORPORATED THESE ADJUSTMENTS IN YOUR REBUTTAL COST OF
21 SERVICE?

22 A. No. Since the Company has demonstrated that these adjustments are not
23 appropriate, I have not included them in my rebuttal cost of service.

24

1 **B. Sherco 1 & 2 Depreciation**

2 Q. WHAT ADJUSTMENT HAS MR. MUGRACE MADE WITH RESPECT TO SHERCO 1&2
3 DEPRECIATION?

4 A. Mr. Mugrace recommends removal of the \$3.483 million from the Company's
5 Depreciation Expense and the associated rate base and deferred tax impacts
6 related to the retirement of Sherco Units 1 and 2 in 2026 and 2023,
7 respectively. This amount was revised to \$2.929 million in NDPSC Advocacy
8 Staff's response to XE-2-001 and XE-2-002. Mr. Mugrace argues that the
9 Company's plan to retire the plants in 2023 and 2026 was not prudent and the
10 current North Dakota depreciation schedule for Sherco Units 1 and 2 should
11 be maintained.

12

13 Q. WAS THE ADJUSTMENT PROPOSED BY MR. MUGRACE CALCULATED
14 CORRECTLY?

15 A. No, Mr. Mugrace calculated the adjustment incorrectly. First, the adjustment
16 proposed by the Company in Direct Testimony related to the production
17 depreciation study included adjustments to other production plants. Second,
18 there are two components to the depreciation expense calculation for Sherco
19 Units 1 and 2. The first is the depreciation of the capitalized value (the return
20 of the investment); and the second component is the recovery for the cost to
21 remove the asset. The cost to remove the asset is also referred to as the net
22 salvage percent. Based on Mr. Mugrace's proposed adjustment, only the first
23 component should be adjusted from the Company's cost of service.
24 Therefore, the correct calculation of this adjustment to remove the proposed
25 depreciation life change for Sherco 1 and 2 is \$2.693 million as shown on
26 Schedule 5, column 22, row 84.

27

1 Q. DO YOU AGREE THAT THIS ADJUSTMENT IS APPROPRIATE?

2 A. No. As discussed in the Direct Testimony of Company Witness Mr.
3 Christopher Shaw and the Rebuttal Testimony of Company Witness Ms.
4 Farah Mandich, the Company's plan to retire Sherco Units 1 and 2 in 2026
5 and 2023 was prudent based on the Company's overall analysis of the costs
6 and regulatory risks to the facility, and subsequent analyses have further
7 demonstrated the prudence of this decision. Therefore, I am not adjusting
8 Sherco Units 1 and 2 from Depreciation Expense.

9

10 **C. Prairie Island Extended Power Uprate (PI EPU) Project**

11 Q. WHAT ADJUSTMENT HAS MR. MUGRACE MADE WITH RESPECT TO PI EPU
12 PROJECT?

13 A. Mr. Mugrace recommends removal of the abandonment cost amortization of
14 the PI EPU project from the Company's 2021 test year COSS. Mr. Mugrace
15 argues this adjustment is necessary because the Company is requesting
16 recovery of investments that are not used or useful in the provision of utility
17 service.

18

19 Q. WAS THIS ADJUSTMENT CALCULATED APPROPRIATELY?

20 A. No. Mr. Mugrace assumed tax depreciation on the PI EPU project when
21 making his adjustment. Since the project was expensed for tax purposes in
22 2012 and 2013, no adjustment is needed for tax depreciation related to the PI
23 EPU project. The correct adjustment is \$0.488 million as shown on Schedule
24 5, column 20, row 84.

25

1 Q. DO YOU AGREE THAT THIS ADJUSTMENT IS APPROPRIATE?

2 A. No. As discussed in the Rebuttal Testimony of Ms. Farah Mandich, the
3 Company's decisions to undertake and subsequently abandon the PI EPU
4 project were prudent. Therefore, I am not making an adjustment to remove PI
5 EPU from the 2021 test year COSS.

6

7 **D. Depreciation Study: TD&G**

8 Q. WHAT ADJUSTMENT HAS MR. MUGRACE MADE WITH RESPECT TO
9 DEPRECIATION STUDY: TD&G?

10 A. Mr. Mugrace recommends a reduction of \$0.380 million, which reflects
11 Commission Advocacy Staff Witness Mr. James Garren's proposed
12 adjustment to depreciation rates and expenses.

13

14 Q. DO YOU AGREE THAT THIS ADJUSTMENT IS APPROPRIATE?

15 A. No. The Company disagrees with the concept of this adjustment and the way
16 Mr. Garren calculated the adjustment. The Rebuttal Testimony of Mr. Moeller
17 provides numerous reasons why Mr. Garren's adjustment is not accurate and
18 should be rejected. Therefore, I have not made an adjustment to the 2021
19 COSS to account for Mr. Garren's proposal.

20

21 **E. 187 Solar**

22 Q. WHAT ADJUSTMENT HAS MR. MUGRACE MADE WITH RESPECT TO 187 MW
23 SOLAR?

24 A. Mr. Mugrace recommends removing the **[TRADE SECRET DATA**
25 **BEGINS** **TRADE SECRET DATA ENDS]** in Fuel and
26 Purchased Energy costs associated with the 187 MW Solar Portfolio from the
27 2021 test year COSS. Mr. Mugrace argues that these costs should not be

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1 recovered because the Commission initially denied an Advance Determination
2 of Prudence (ADP) for the 187 MW Solar Portfolio in Case No. PU-14-810.

3

4 Q. WAS THIS ADJUSTMENT CALCULATED CORRECTLY?

5 A. No. The 187 MW Solar Portfolio comprises two power purchase agreements,
6 the costs of which are recovered through the FCR. Even if the Commission
7 does not agree that these costs are prudent, the removal of these costs from
8 rates has no impact on base rates. Consequently, the appropriate adjustment
9 for Mr. Mugrace's recommendation is \$0 in the Company's cost of service.

10

11 Q. PLEASE EXPAND ON YOUR ANSWER?

12 A. As explained on page 20 of my Direct Testimony, an adjustment was made to
13 the 2021 test year COSS to ensure there is no base rate impact of these costs
14 as these costs, if approved, would be recovered in the FCR and not in base
15 rates. Therefore, no adjustment is necessary to remove these costs from the
16 2021 test year COSS. Additionally, as explained in the Rebuttal Testimony of
17 Ms. Mandich, the Company maintains that its acquisition of the 187 MW Solar
18 Portfolio was prudent.

19

20 **F. Aviation**

21 Q. WHAT ADJUSTMENT HAS MR. MUGRACE MADE WITH RESPECT TO AVIATION?

22 A. Mr. Mugrace recommends removing all aviation costs from rates, a total
23 adjustment of \$0.199 million. Mr. Mugrace argues that the Company's cost-
24 benefit analysis, which determined the use of corporate aviation to be
25 effective, only accounted for benefits to the Company, not benefits to
26 ratepayers. Thus, he argues that the Company should only recover travel
27 expenses for commercial airline costs.

1 Q. DO YOU AGREE THAT THIS ADJUSTMENT IS APPROPRIATE?

2 A. No. As explained in the Rebuttal Testimony of Company Witness Mr. Greg
3 Chamberlain, ratepayers benefit from the Company's use of its airplanes.
4 Additionally, the Company is only seeking to recover half of its aviation
5 expenses through base rates as proposed in its initial filing. Consequently, I
6 am not removing the additional 50 percent of aviation costs.

7

8 **G. Donations and Chamber of Commerce Dues**

9 Q. WHAT ADJUSTMENT IS MADE WITH RESPECT TO CHAMBER OF COMMERCE
10 DUES AND CHARITABLE CONTRIBUTIONS?

11 A. Mr. Mugrace proposes disallowing all Chamber of Commerce dues and
12 charitable contributions. He asserts that these dues and charitable
13 contributions provide no benefit to ratepayers.

14

15 Q. DOES THE COMPANY AGREE WITH THIS ADJUSTMENT?

16 A. No. As Mr. Chamberlain explains in his Rebuttal Testimony, Chamber of
17 Commerce dues and charitable contributions are normal and expected
18 business expenses that provide benefits to North Dakota ratepayers. The
19 Company is seeking recovery of 50 percent of the costs for these important
20 mechanisms for supporting the communities and organizations in the areas we
21 serve. Consequently, I have included those costs in our calculation of the
22 revenue requirement.

23

24 **H. Economic Development Donations**

25 Q. WHAT IS THE ISSUE WITH RESPECT TO ECONOMIC DEVELOPMENT?

26 A. Mr. Mugrace recommends denial of the \$0.103 million included for Economic
27 Development.

1 Q. DOES THE COMPANY AGREE WITH THAT ADJUSTMENT?

2 A. No. As Mr. Chamberlain explains in his Rebuttal Testimony, the economic
3 development expenses in question provide benefits for North Dakota,
4 including Xcel Energy customers. We request that the Commission continue
5 to support our economic development efforts on behalf of the communities
6 we serve, and I have included those costs in our calculation of the revenue
7 requirement.

8

9 **I. Incentive Compensation**

10 Q. WHAT ADJUSTMENT HAS MR. MUGRACE MADE WITH RESPECT TO INCENTIVE
11 COMPENSATION?

12 A. Mr. Mugrace recommends including Incentive Compensation costs of up to
13 15 percent of base pay in rates, which is a continuation of what the Company
14 is currently permitted to recover. The Company has proposed to include
15 Incentive Compensation costs of up to 20 percent of base pay. Mr. Mugrace's
16 proposal results in an adjustment of \$0.252 million.

17

18 Q. WAS THE ADJUSTMENT PROPOSED BY MR. MUGRACE CALCULATED
19 CORRECTLY?

20 A. No. On pages 37 and 53 of his Direct Testimony, Mr. Mugrace recommends
21 the Commission maintain Annual Incentive Plan (AIP) recovery at 15 percent,
22 and states this recommendation is the basis for his adjustment. If the
23 Commission agrees with the intent of Mr. Mugrace adjustment as stated, the
24 decrease to revenue requirement should be \$0.081 million. The Company
25 provided this amount in its Interim petition and adjustments.

26

1 Q. DO YOU AGREE THAT THIS ADJUSTMENT IS APPROPRIATE?

2 A. No. As explained by Mr. Chamberlain in his Rebuttal Testimony, the
3 Company's proposal would increase our ability to attract and keep key
4 employees, which benefits ratepayers. Therefore, I did not include Mr.
5 Mugrace's reduction to Incentive Compensation costs.

6

7 **J. Income Tax Tracker**

8 Q. WHAT ADJUSTMENT HAS MR. MUGRACE MADE WITH RESPECT TO THE INCOME
9 TAX TRACKER?

10 A. Mr. Mugrace recommends an amortization period of 3.5 years instead of 3
11 years as proposed by the Company. He notes the Company's prior rate case
12 applications with the ND Commission as a basis for his 3.5-year
13 recommendation for rate case expenses and the Company's Income Tax
14 Tracker.

15

16 Q. WHY HAS THE COMPANY PROPOSED A THREE-YEAR AMORTIZATION OF ONE-
17 TIME EXPENSES?

18 A. As I explained in my Direct Testimony at page 59 and 60, we proposed the
19 amortization of one-time expenses over a three-year period. This period was
20 chosen to match the period we expect rates to remain in effect as a result of
21 this rate case.

22

23 Q. DO YOU AGREE THAT THIS ADJUSTMENT IS APPROPRIATE?

24 A. No. We believe a three-year amortization better aligns with the estimated time
25 between rate cases. However, if the Commission agrees with Mr. Mugrace's
26 assessment, the Company will change its assumed amortization period to 3.5-
27 years.

1 **K. Rate Case Expenses**

2 Q. WHAT ADJUSTMENT HAS MR. MUGRACE MADE WITH RESPECT TO RATE CASE
3 EXPENSES?

4 A. Mr. Mugrace recommends an amortization period of 3.5 years for rate case
5 expenses instead of 3 years as proposed by the Company.

6

7 Q. DO YOU AGREE THAT THIS ADJUSTMENT IS APPROPRIATE?

8 A. No. As I discussed above, the Company proposed amortization of one-time
9 expenses over a three-year period to match the period we expect rates to
10 remain in effect as a result of this rate case. However, if the Commission
11 agrees with Mr. Mugrace's assessment, the Company will change its assumed
12 amortization period to 3.5-years.

13

14 **L. Jeffers Wind and Community Wind North**

15 Q. WHAT ADJUSTMENT HAS MR. MUGRACE MADE WITH RESPECT TO JEFFERS
16 WIND AND COMMUNITY WIND NORTH?

17 A. Mr. Mugrace recommends removal of \$9.373 million of plant and the
18 associated rate base and income statement items related to the Jeffers Wind
19 and Community Wind North projects from the 2021 test year COSS. Mr.
20 Mugrace states that the Company is relying on the Minnesota Public Utilities
21 Commission's (MPUC) approval of the Jeffers Wind and Community Wind
22 North projects for prudence, which he argues should have no bearing on the
23 Commission's decision.

24

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1 Q. WAS THE ADJUSTMENT PROPOSED BY MR. MUGRACE CALCULATED
2 CORRECTLY?

3 A. No. The Company disagrees with the amount of this adjustment. The
4 amount provided for the removal of Jeffers Wind and Community Wind
5 North does not include the revenue offset that would be received from NSPW
6 through the Interchange Agreement. If the Commission agrees with Mr.
7 Mugrace's adjustment, the decrease to revenue requirement should be \$0.689
8 million as shown on Schedule 5, column 12, row 84.

9
10 Q. DO YOU AGREE THAT THIS ADJUSTMENT IS APPROPRIATE?

11 A. No. As discussed in the Direct Testimony of Mr. Shaw and the Rebuttal
12 Testimony of Ms. Mandich, the Company's additions of the Jeffers Wind and
13 Community Wind North resources were prudent. Therefore, I am not making
14 an adjustment to the 2021 test year COSS to remove Jeffers Wind and
15 Community Wind North.

16
17 Q. WHAT WILL HAPPEN IF THE COMMISSION ACCEPTS MR. MUGRACE'S REMOVAL
18 OF JEFFERS WIND AND COMMUNITY WIND NORTH?

19 A. As discussed further by Ms. Mandich, denying recovery in base rates for
20 Jeffers Wind and Community Wind North will result in North Dakota
21 customers receiving the energy benefits of these resources without
22 contributing toward the costs, because the PPA costs will no longer be
23 recovered through the FCR. Additionally, the shifting of Jeffers Wind and
24 Community Wind North from PPAs to Company-owned resources means
25 that their fuel cost is zero, causing downward pressure on the system average
26 cost of fuel to the benefit of North Dakota customers. As a result, as
27 discussed in Ms. Mandich's testimony, the Company believes a revenue offset

1 is appropriate if the Commission accepts Mr. Mugrace's removal of Jeffers
2 Wind and Community Wind North.

3

4 **M. Mankato Energy Center II PPA**

5 Q. WHAT ADJUSTMENT HAS MR. MUGRACE MADE WITH RESPECT TO THE MEC II
6 PPA?

7 A. Mr. Mugrace recommends disallowance of the **[TRADE SECRET BEGINS**
8 **TRADE SECRET ENDS]** in cost related to the MEC II
9 PPA. Mr. Mugrace argues that the Commission previously denied an ADP for
10 the MEC II PPA and the costs of the MEC II PPA are not known and
11 measurable, prudent in nature, and used and useful in the provision of utility
12 service because they reflected capacity projections made at the time.

13

14 Q. WAS THE ADJUSTMENT PROPOSED BY MR. MUGRACE CALCULATED
15 CORRECTLY?

16 A. No. The Company disagrees with the amount of this adjustment. The
17 **[TRADE SECRET BEINGS** **TRADE SECRET ENDS]**
18 provided as the cost of the MEC II PPA does not include the revenue offset
19 that would be received from NSPW through the Interchange Agreement. If
20 the Commission agrees with Mr. Mugrace's adjustment, the decrease to
21 revenue requirement should be **[TRADE SECRET BEGINS**
22 **TRADE SECRET**
23 **ENDS]**

24

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1 Q. DO YOU AGREE THAT THIS ADJUSTMENT IS APPROPRIATE?

2 A. No. As discussed in Ms. Mandich's Rebuttal Testimony, the Company's
3 addition of the MEC II PPA was prudent. Therefore, I am not removing the
4 MEC II PPA costs.

5

6 **N. ND RTF Amortization**

7 Q. WHAT ADJUSTMENT HAS MR. MUGRACE MADE WITH RESPECT TO ND RTF
8 AMORTIZATION?

9 A. Mr. Mugrace recommends that the Company not recover RTF amortization
10 costs in rates, because the RTF is moot and does not provide any benefits to
11 North Dakota ratepayers.

12

13 Q. DO YOU AGREE THAT THIS ADJUSTMENT IS APPROPRIATE?

14 A. No. As Mr. Chamberlain explained in his Direct Testimony, the Company
15 developed and submitted the RTF pursuant to an agreement between the
16 Company and Commission Staff in the Settlement in Case No. PU-12-813.
17 As a result, recovery of the transaction costs associated with the RTF is
18 appropriate and I am not removing these costs from the 2021 test year COSS.

19

20 **O. Non-plant and Other Rate Base**

21 Q. WHAT IS NON-PLANT AND OTHER RATE BASE?

22 A. Non-plant and Other Rate Base are balance sheet accounts that accumulate
23 expense provisions for items not expected to be paid in one year. This
24 includes in order of absolute magnitude, pension and retiree medical expenses,
25 deferred rent expense and litigation reserve.

26

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1 Q. WHAT ADJUSTMENT HAS MR. MUGRACE MADE WITH RESPECT TO NON-PLANT
2 AND OTHER RATE BASE?

3 A. In his direct testimony, Mr. Mugrace recommends a balance of certain non-
4 plant assets and liabilities assigned to North Dakota of \$6.286 million, which
5 represents a \$2.062 million adjustment to the Company's proposal.

6

7 Q. DO YOU AGREE THAT THIS ADJUSTMENT IS APPROPRIATE?

8 A. No. Mr. Mugrace is removing the Company's deferred pension expense
9 difference related to extending the amortization period for unrecognized
10 pension costs for the NSP Plan from 10 to 20 years, and a "cap and defer"
11 recovery of XES pension costs as approved in the Commission's Order dated
12 February 26, 2014 approving the Revised Second Amended Settlement in Case
13 No. PU-12-813. Since the Commission has approved the recovery of these
14 costs, I have included those costs in our calculation of the revenue
15 requirement.

16

17 **P. Advertising, Association Dues, and Customer Deposits**

18 Q. WHAT ADJUSTMENT HAS MR. MUGRACE MADE WITH RESPECT TO
19 ADVERTISING AND ASSOCIATION DUES?

20 A. Mr. Mugrace recommends maintaining the Company's Advertising and
21 Association Dues expenses at the 2020 level, in part because he argues that the
22 Company did not provide a sufficiently specific breakdown of these costs.

23

24 Q. DO YOU AGREE THAT THIS ADJUSTMENT IS APPROPRIATE?

25 A. No. The Company provided a breakdown of its Advertising and Association
26 Dues expenses in response to a Commission discovery request, and it is
27 unclear what exactly Mr. Mugrace is requesting when he states that the

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1 Company must “identify these costs more precisely.” The Company has
2 properly identified these costs and as a result, I am maintaining the proposed
3 Advertising and Association Dues Expenses.
4

5 Q. WHAT ADJUSTMENT HAS MR. MUGRACE MADE WITH RESPECT TO CUSTOMER
6 DEPOSITS?

7 A. While Mr. Mugrace accepted the Company’s Customer Deposit adjustment of
8 \$1,618, he subtracted an additional \$1,196 to lower the Company’s
9 Precedential Adjustments total on Exhibit BCH-1 Schedule 4 to match the
10 total on Exhibit BCH-1 Schedule 6 line 17. However, Mr. Mugrace neglected
11 to include the payroll taxes associated with these adjustments on line 27 of
12 Schedule 6. When payroll taxes are included in this comparison, no
13 adjustment is necessary.
14

15 **Q. Payroll Tax**

16 Q. WHY DID MR. MUGRACE MAKE AN ADJUSTMENT TO PAYROLL TAXES?

17 A. Mr. Mugrace proposes to adjust the Company’s Payroll Taxes to correspond
18 with his normalization adjustments to the Labor O&M level. Specifically,
19 proposes a \$0.185 million reduction to Payroll Expense and an additional
20 \$1,000 reduction for the Aviation-related payroll tax, since he removed all
21 Aviation expenses as discussed above.
22

23 Q. IS THIS ADJUSTMENT APPROPRIATE?

24 A. No. If the Commission accepts the Company’s position on the recovery of
25 labor normalization and Aviation, this adjustment becomes unnecessary. I
26 have not included it in calculating our revenue requirement.
27

1 **V. COMPANY'S PROPOSED ADJUSTMENTS**

2 **A. FERC Audit**

3 Q. PLEASE DESCRIBE THE ADJUSTMENT RELATED TO THE FERC AUDIT.

4 A. As noted in my direct testimony on page 69, the FERC audit of Xcel Energy
5 Services Inc. (XES) identified an audit finding that impacts costs assigned to
6 the Company, including the 2021 test year. The finding addressed the
7 allocation of capital software to the Company's non-utility affiliates.
8 Historically, capital costs related to software applications have been recorded
9 to the Operating Companies, the primary users of the applications. As other
10 affiliate companies receive indirect benefits of certain corporate software
11 applications, the FERC finding required a retrospective adjustment as well as a
12 prospective change in how software capital costs are recorded, ensuring that
13 all Operating Companies and affiliates that receive direct or indirect benefits
14 receive a portion of the capital charges.

15
16 Our interim rate petition was corrected to include the adjustment to remove a
17 portion of the software applications allocated to the Company related to this
18 audit finding. This adjustment impacts the 2021 test year revenue
19 requirements by the amounts shown on Schedule 4, page 1, row 39, column 4.
20

21 **B. RER PTC Amortization**

22 Q. PLEASE DESCRIBE THE REBUTTAL ADJUSTMENT RELATED TO RER PTC
23 AMORTIZATION.

24 A. The Company is proposing to use the "Levelized Credit Method," or LCM to
25 spread the PTC benefits to customers over the life of the applicable resource.
26 However, when completing a final validation on the PTC amounts in the
27 COSS, we identified that the adjustment inadvertently excluded the

1 Community Wind North, Jeffers Wind and Mower Wind projects from the
2 calculation of the LCM. This change will increase the overall deficiency.

3
4 Our interim rate petition was corrected to include the adjustment to RER
5 PTC Amortization. This adjustment impacts the 2021 test year revenue
6 requirements by the amounts shown on Schedule 4, page 1, row 39, column 5.
7

8 VI. SECONDARY CALCULATIONS

9 A. ADIT Prorate – IRS Required

10 Q. PLEASE DESCRIBE THE ADIT PRORATE ADJUSTMENT THAT IS REQUIRED BY
11 THE IRS AND INCLUDED IN THESE SECONDARY CALCULATIONS.

12 A. In general, the IRS tax regulations in Sec. 1.167(l) define a prorated schedule
13 for the extent average accumulated deferred income taxes (ADIT) can be used
14 to reduce rate base to comply with the tax normalization requirements of the
15 Code when forecast information is used to set rates. Given that the
16 Company's filing utilizes forecast test year data, this condition applies. This
17 has been supported by a number of Private Letter Rulings (PLRs) issued by
18 the IRS. In addition, FERC approved the proration logic included in the
19 Company's Attachment O-NSP transmission formula rate of the MISO Open
20 Access Transmission, Energy and Operating Reserve Markets Tariff in Docket
21 No. ER18-2322-000.

22
23 This secondary calculation limits the ADIT deduction from rate base by
24 applying the IRS defined prorate method to only the forecast entries to this
25 balance. As noted in my direct testimony on page 70, we inadvertently used a

1 prorate factor in our model that created a double average. This has been
2 corrected in the 2021 Rebuttal test year COSS.

3

4 The updated ADIT prorate factor and its impact on the adjustments to the
5 COSS discussed above is shown on Schedule 4, page 1, row 39, column 6.

6

7 **B. Cash Working Capital**

8 Q. DID MR. MUGRACE RECOMMEND ANY ADJUSTMENT TO CASH WORKING
9 CAPITAL FOR THE TEST YEAR?

10 A. Yes, Mr. Mugrace included a recalculation of Cash Working Capital (CWC)
11 based upon applying his recommended adjustments for revenues, O&M
12 expenses, and taxes to the Company cash working capital formula from the
13 Cost of Service model.

14

15 Q. DOES THE COMPANY AGREE WITH THE CWC CALCULATIONS PROPOSED BY
16 MR. MUGRACE?

17 A. Not completely. The Company agrees with the calculation methodology, but
18 not with the amount calculated by Mr. Mugrace. The final level of CWC to be
19 included in this proceeding is a function of the final Commission approved
20 revenue and expenses and tax calculations. This calculation will need to be
21 revised after the Commission determines the final revenue requirement as
22 these decisions will impact the level of CWC. Once the final adjustments
23 have been ordered, the Company will recalculate the CWC level to be included
24 in final rates. The calculation of the final CWC level is historically performed
25 as part of a compliance filing proposing final rates.

26

1 **C. Deferred Tax Credits**

2 Q. IS THE COMPANY PROPOSING AN ADJUSTMENT TO BASE RATES RELATED TO
3 DEFERRED TAX CREDITS IN THIS CASE?

4 A. Yes. The Company is utilizing federal tax credits during the 2021 test year,
5 but due to the amount of federal tax credits earned during the year, the
6 deferred tax asset is increasing. As noted previously in my Direct Testimony,
7 any changes in the revenues, expenses, or capital structure will cause the
8 income tax calculation to be changed. This could in turn affect the timing of
9 the DTAs being generated or consumed and added to or removed from rate
10 base.

11

12 This adjustment impacts the 2021 test year revenue requirements by the
13 amounts shown on Schedule 4, page 1, row 39, column 6.

14

15 **D. Change in Cost of Capital**

16 Q. PLEASE DESCRIBE THE REBUTTAL ADJUSTMENT RELATED TO COST OF
17 CAPITAL.

18 A. The Company's 2021 test year COSS inadvertently used a different capital
19 structure than the capital structure included in the direct testimony of Dylan
20 D'Ascentis and agreed to in the rebuttal testimony of Sarah Soong. The
21 difference was due to the vintage of capital structure used and only impacts
22 the required rate of return by one basis point. We are adjusting the required
23 rate of return from 7.35 percent to 7.34 percent. This adjustment corrects the
24 2021 test year COSS for this capital structure change.

25

1 **E. Federal and State Income Taxes**

2 Q. DID MR. MUGRACE CALCULATE A LEVEL OF FEDERAL AND STATE INCOME
3 TAXES TO BE INCLUDED IN THE TEST YEAR?

4 A. Yes. Mr. Mugrace included a calculation of both Federal and State Income
5 Taxes in his Schedule DM-26.

6

7 Q. DID THE COMPANY REVIEW MR. MUGRACE'S SCHEDULE DM-23 AND 24, AND
8 DO YOU HAVE ANY ISSUES WITH THE CALCULATIONS OF FEDERAL AND STATE
9 INCOME TAXES TO BE INCLUDED IN THE TEST YEAR?

10 A. Yes, the Company reviewed Mr. Mugrace's calculations and identified the
11 following errors in his Schedule DM-23 and 24 calculation of State and
12 Federal Income Taxes.

13 1) The proposed deficiency of \$3.590 million is not included in
14 the calculation of state and federal income taxes.

15 2) The proposed plant adjustment of \$17.912 million is used as
16 the adjustment for tax depreciation. The actual tax
17 depreciation based on the proposed removal of PI EPU, Jeffers
18 and Community Wind North and AGIS is \$3.106 million.

19 3) The weighted cost of debt used does not match the proposed
20 weighted average cost of debt.

21 4) State and federal income tax credits were not utilized as
22 applicable.

23

24 Q. WHAT IS THE IMPACT OF THESE ERRORS ON MR. MUGRACE'S INCOME TAX
25 CALCULATIONS?

26 A. The impact of these errors in the income tax calculations result in an
27 overstatement of the revenue requirements for the test year.

**PUBLIC DOCUMENT - NOT PUBLIC
DATA HAS BEEN EXCISED**

1 Q. DOES THIS ERROR NEED TO BE CORRECTED IN MR. MUGRACE'S CALCULATION
2 OF THE REVENUE REQUIREMENT FOR THE TEST YEAR?

3 A. For purposes of correcting the record in this case, Mr. Mugrace's testimony
4 and schedules impacted by this error should be corrected. However, the final
5 calculation of Federal and State Income Taxes to be included in the test year
6 will be a function of the final approved levels of revenue, expense, rate base
7 and weighted cost of capital approved by the Commission.

8

9 **F. Interest Synchronization**

10 Q. DID MR. MUGRACE RECOMMEND ANY ADJUSTMENT TO INTEREST
11 SYNCHRONIZATION FOR THE TEST YEAR?

12 A. Yes. Mr. Mugrace included a recalculation of Interest Synchronization
13 (referred to by Mr. Mugrace as Debt Interest Expense), based upon applying
14 his recommended rate base level and the recommended weighted cost of
15 interest as proposed by Advocacy Staff witness Mr. Marlon F. Griffing for this
16 proceeding. This results in a proposed adjustment of \$0.360 million.

17

18 Q. DOES THE COMPANY AGREE WITH THE INTEREST SYNCHRONIZATION
19 CALCULATIONS PROPOSED BY MR. MUGRACE?

20 A. Not completely. The Company agrees with the calculation methodology, but
21 not with the amount calculated by Mr. Mugrace. The final level of interest
22 synchronization to be included in this proceeding is a function of the final
23 Commission approved rate base, the final approved debt/equity capitalization
24 ratio, and the approved weighted cost of debt. After the Commission rules on
25 these issues, the interest synchronization calculation can be finalized. The
26 calculation of the final interest synchronization level is historically performed
27 as part of a compliance filing proposing final rates.

VII. CONCLUSION

1

2

3 Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS TO THE COMMISSION.

4 A. I recommend the Commission determine an overall retail revenue requirement
5 of \$224.297 million and a 2021 revenue deficiency of \$17.880 million for the
6 Company's North Dakota jurisdictional electric operations, determined by the
7 cost of service for the 2021 test year.

8

9 Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?


10 A. Yes, it does.

1 STATE OF NORTH DAKOTA
2 BEFORE THE
3 PUBLIC SERVICE COMMISSION
4
5

6 In the Matter of the Application of Northern)
7 States Power Company, a Minnesota Corporation)
8 For Authority to Increase Rates for Electric Service) Case No. PU-20-441
9 in North Dakota)

10
11
12
13 AFFIDAVIT OF
14 Benjamin C. Halama
15
16

17 I, the undersigned, being duly sworn, depose and say that the foregoing is the
18 Rebuttal Testimony of the undersigned, and that such Rebuttal Testimony and the
19 exhibits or schedules sponsored by me to the best of my knowledge, information
20 and belief, are true, correct, accurate and complete, and I hereby adopt said testimony
21 as if given by me in formal hearing, under oath.

22
23
24 
25 Benjamin C. Halama
26
27
28
29

30 Subscribed and sworn to before me, this 26 day of May, 2021.
31

32 
33 _____
34 Notary Public
35 My Commission Expires: 1/31/2025
36



NSPM - 00 Complete Revenue Requirements by Jurisdiction, Yr 2 - DRAFT	Dec - 2021		
	Total	ND Electric	Other
<u>Composite Income Tax Rate</u>			
State Tax Rate	4.31%	4.31%	4.31%
Federal Statutory Tax Rate	21.00%	21.00%	21.00%
<u>Federal Effective Tax Rate</u>	<u>20.09%</u>	<u>20.09%</u>	<u>20.09%</u>
Composite Tax Rate	24.40%	24.40%	24.40%
Revenue Conversion Factor (1/(1--Composite Tax Rate))	1.322837	1.322837	1.322837
<u>Weighted Cost of Capital</u>			
Active Rates and Ratios Version	Rebuttal	Rebuttal	Rebuttal
Cost of Short Term Debt	1.00%	1.00%	1.00%
Cost of Long Term Debt	4.22%	4.22%	4.22%
Cost of Common Equity	10.20%	10.20%	10.20%
Ratio of Short Term Debt	0.78%	0.78%	0.78%
Ratio of Long Term Debt	46.72%	46.72%	46.72%
Ratio of Common Equity	52.50%	52.50%	52.50%
Weighted Cost of STD	0.01%	0.01%	0.01%
Weighted Cost of LTD	1.97%	1.97%	1.97%
Weighted Cost of Debt	1.98%	1.98%	1.98%
<u>Weighted Cost of Equity</u>	<u>5.36%</u>	<u>5.36%</u>	<u>5.36%</u>
Required Rate of Return	7.34%	7.34%	7.34%
<u>Rate Base</u>			
Plant Investment	24,859,038,913	1,467,641,324	23,391,397,589
<u>Depreciation Reserve</u>	<u>11,356,647,786</u>	<u>677,159,331</u>	<u>10,679,488,455</u>
Net Utility Plant	13,502,391,127	790,481,993	12,711,909,134
CWIP	31,625,665	1,914,024	29,711,641
Accumulated Deferred Taxes	3,060,843,149	184,529,916	2,876,313,233
DTA - NOL Average Balance	(18,117,476)		(18,117,476)
DTA - State Tax Credit Average Balance	(338,015)	(28,091)	(309,924)
DTA - Federal Tax Credit Average Balance	<u>(492,192,061)</u>	<u>(36,499,165)</u>	<u>(455,692,896)</u>
Total Accum Deferred Taxes	2,550,195,598	148,002,660	2,402,192,938
Cash Working Capital	(144,479,728)	(7,125,146)	(137,354,583)
Materials and Supplies	174,923,376	10,806,596	164,116,780
Fuel Inventory	97,123,363	6,579,039	90,544,324
Non-plant Assets and Liabilities	88,306,992	8,415,116	79,891,876
Customer Advances	(9,169,912)	(62,381)	(9,107,531)
Customer Deposits	(44,930,376)	(71,274)	(44,859,102)
Prepays and Other	80,616,733	5,159,576	75,457,157
<u>Regulatory Amortizations</u>	<u>90,887,753</u>	<u>4,140,882</u>	<u>86,746,871</u>
Total Other Rate Base Items	333,278,199	27,842,408	305,435,791
Total Rate Base	11,317,099,394	672,235,766	10,644,863,628
<u>Operating Revenues</u>			
Retail	3,532,781,563	206,416,272	3,326,365,292
Interdepartmental	455,964		455,964
<u>Other Operating Rev - Non-Retail</u>	<u>768,001,918</u>	<u>39,560,502</u>	<u>728,441,416</u>
Total Operating Revenues	4,301,239,446	245,976,774	4,055,262,672

NSPM - 00 Complete Revenue Requirements by Jurisdiction, Yr 2 - DRAFT	Dec - 2021		
	Total	ND Electric	Other

Expenses

Operating Expenses:

Fuel	986,476,304	53,350,866	933,125,438
Deferred Fuel			
Variable IA Production Fuel			
<u>Purchased Energy - Windsourse</u>	<u>6,003,946</u>	<u>0</u>	<u>6,003,946</u>
Fuel & Purchased Energy Total	992,480,250	53,350,866	939,129,384
Production - Fixed	501,063,754	31,066,266	469,997,488
Production - Fixed IA Investment			
Production - Fixed IA O&M	49,291,953	3,042,842	46,249,111
Production - Variable	7,960,889	510,248	7,450,641
Production - Variable IA O&M	17,067,287	1,053,581	16,013,706
<u>Production - Purchased Demand</u>	<u>160,569,589</u>	<u>9,827,919</u>	<u>150,741,670</u>
Production Total	735,953,471	45,500,855	690,452,616
Regional Markets	11,099,571	685,188	10,414,384
Transmission IA	120,157,595	7,417,449	112,740,147
Transmission	268,574,522	10,151,545	258,422,977
Distribution	155,178,158	7,759,179	147,418,978
Customer Accounting	72,729,589	3,898,156	68,831,432
Customer Service & Information	112,693,003	284,060	112,408,942
Sales, Econ Dvlp & Other	467,488	118,859	348,629
<u>Administrative & General</u>	<u>264,285,526</u>	<u>16,782,031</u>	<u>247,503,495</u>
Total Operating Expenses	2,733,619,174	145,948,190	2,587,670,984
Depreciation	880,763,354	54,105,447	826,657,907
Amortization	21,750,511	6,767,021	14,983,490

Taxes:

Property Taxes	216,754,203	11,495,109	205,259,093
ITC Amortization	(1,365,779)	(67,761)	(1,298,018)
Deferred Taxes	100,146,620	4,857,062	95,289,557
Deferred Taxes - NOL	2,227,623		2,227,623
Less State Tax Credits deferred	(73,207)	(56,182)	(17,026)
Less Federal Tax Credits deferred	(176,103,702)	(12,302,145)	(163,801,557)
Deferred Income Tax & ITC	(75,168,445)	(7,569,025)	(67,599,420)
Payroll & Other Taxes	32,033,321	2,031,768	30,001,552
Total Taxes Other Than Income	173,619,078	5,957,853	167,661,226

Income Before Taxes

Total Operating Revenues	4,301,239,446	245,976,774	4,055,262,672
less: Total Operating Expenses	2,733,619,174	145,948,190	2,587,670,984
Book Depreciation	880,763,354	54,105,447	826,657,907
Amortization	21,750,511	6,767,021	14,983,490
<u>Taxes Other than Income</u>	<u>173,619,078</u>	<u>5,957,853</u>	<u>167,661,226</u>
Total Before Tax Book Income	491,487,329	33,198,263	458,289,066

Tax Additions

Book Depreciation	880,763,354	54,105,447	826,657,907
Deferred Income Taxes and ITC	(75,168,445)	(7,569,025)	(67,599,420)

NSPM - 00 Complete Revenue Requirements by Jurisdiction, Yr 2 - DRAFT	Dec - 2021		
	Total	ND Electric	Other
Nuclear Fuel Burn (ex. D&D)	113,804,577	7,025,270	106,779,307
Nuclear Outage Accounting	45,490,790	2,952,752	42,538,038
Avoided Tax Interest	19,967,384	532,880	19,434,504
<u>Other Book Additions</u>	<u>5,887,911</u>	<u>581,747</u>	<u>5,306,165</u>
Total Tax Additions	990,745,570	57,629,071	933,116,500
<u>Tax Deductions</u>			
Total Rate Base	11,317,099,394	672,235,766	10,644,863,628
Weighted Cost of Debt	<u>1.98%</u>	<u>1.98%</u>	<u>1.98%</u>
Debt Interest Expense	224,078,568	13,310,268	210,768,300
Nuclear Outage Accounting	62,275,000	4,060,372	58,214,627
Tax Depreciation and Removals	1,485,296,388	85,837,307	1,399,459,080
NOL Utilized / (Generated)	7,924,890		7,924,890
<u>Other Tax / Book Timing Differences</u>	<u>(1,864,323)</u>	<u>(282,512)</u>	<u>(1,581,811)</u>
Total Tax Deductions	1,777,710,522	102,925,436	1,674,785,086
<u>State Taxes</u>			
State Taxable Income	(295,477,622)	(12,098,102)	(283,379,520)
State Income Tax Rate	<u>4.31%</u>	<u>4.31%</u>	<u>4.31%</u>
State Taxes before Credits	(12,735,085)	(521,428)	(12,213,657)
<u>Less State Tax Credits applied</u>	<u>(1,113,793)</u>	<u>(17,093)</u>	<u>(1,096,700)</u>
Total State Income Taxes	(13,848,878)	(538,521)	(13,310,357)
<u>Federal Taxes</u>			
Federal Sec 199 Production Deduction			
Federal Taxable Income	(281,628,743)	(11,559,580)	(270,069,163)
Federal Income Tax Rate	<u>21.00%</u>	<u>21.00%</u>	<u>21.00%</u>
Federal Tax before Credits	(59,142,036)	(2,427,512)	(56,714,524)
<u>Less Federal Tax Credits</u>	<u>(6,314,652)</u>	<u>338,807</u>	<u>(6,653,459)</u>
Total Federal Income Taxes	(65,456,688)	(2,088,705)	(63,367,983)
Total Taxes			
Total Taxes Other than Income	173,619,078	5,957,853	167,661,226
Total Federal and State Income Taxes	(79,305,567)	(2,627,227)	(76,678,340)
Total Taxes	94,313,511	3,330,626	90,982,885
Total Operating Revenues	4,301,239,446	245,976,774	4,055,262,672
Total Expenses	3,730,446,550	210,151,284	3,520,295,266
AFDC Debt			
AFDC Equity			
Net Income	570,792,896	35,825,490	534,967,406
<u>Rate of Return (ROR)</u>			
Total Operating Income	570,792,896	35,825,490	534,967,406
<u>Total Rate Base</u>	<u>11,317,099,394</u>	<u>672,235,766</u>	<u>10,644,863,628</u>
ROR (Operating Income / Rate Base)	5.04%	5.33%	5.03%
<u>Return on Equity (ROE)</u>			

NSPM - 00 Complete Revenue Requirements by Jurisdiction, Yr 2 - DRAFT	Dec - 2021		
	Total	ND Electric	Other
Net Operating Income	570,792,896	35,825,490	534,967,406
Debt Interest (Rate Base * Weighted Cost of Debt)	(224,078,568)	(13,310,268)	(210,768,300)
Earnings Available for Common	346,714,328	22,515,222	324,199,106
<u>Equity Rate Base (Rate Base * Equity Ratio)</u>	<u>5,941,477,182</u>	<u>352,923,777</u>	<u>5,588,553,405</u>
ROE (earnings for Common / Equity)	5.84%	6.38%	5.80%
Revenue Deficiency			
Required Operating Income (Rate Base * Required Return)	830,675,095	49,342,105	781,332,990
<u>Net Operating Income</u>	<u>570,792,896</u>	<u>35,825,490</u>	<u>534,967,406</u>
Operating Income Deficiency	259,882,200	13,516,615	246,365,584
Revenue Conversion Factor (1/(1--Composite Tax Rate))	1.322837	1.322837	1.322837
Revenue Deficiency (Income Deficiency * Conversion Facto	343,781,805	17,880,280	325,901,526
Total Revenue Requirements			
Total Retail Revenues	3,533,237,528	206,416,272	3,326,821,256
<u>Revenue Deficiency</u>	<u>343,781,805</u>	<u>17,880,280</u>	<u>325,901,526</u>
Total Revenue Requirements	3,877,019,333	224,296,552	3,652,722,782

Statement of Operating Income
 (000's)

Line No.	Description	2021 Test Year As Filed	Rebuttal Adjustments	2021 Rebuttal Test Year
<u>Operating Revenues</u>				
1	Retail	\$206,416	\$0	\$206,416
2	Other Operating	<u>\$39,560</u>	<u>\$0</u>	<u>\$39,560</u>
3	Total Operating Revenues	\$245,977	\$0	\$245,977
<u>Expenses</u>				
Operating Expenses:				
4	Fuel & Purchased Energy	\$53,351	\$0	\$53,351
5	Power Production	\$46,186	\$0	\$46,186
6	Transmission	\$17,569	\$0	\$17,569
7	Distribution	\$8,529	-\$770	\$7,759
8	Customer Accounting	\$4,008	-\$110	\$3,898
9	Customer Service & Information	\$284	\$0	\$284
10	Sales, Econ Dvlp & Other	\$119	\$0	\$119
11	Administrative & General	<u>\$16,782</u>	<u>\$0</u>	<u>\$16,782</u>
12	Total Operating Expenses	\$146,828	-\$880	\$145,948
13	Depreciation	\$54,544	-\$438	\$54,105
14	Amortizations	\$6,232	\$535	\$6,767
Taxes:				
15	Property	\$11,495	\$0	\$11,495
16	Deferred Income Tax & ITC	-\$7,433	-\$136	-\$7,569
17	Federal & State Income Tax	-\$2,962	\$335	-\$2,627
18	Payroll & Other	<u>\$2,032</u>	<u>\$0</u>	<u>\$2,032</u>
19	Total Taxes	\$3,132	\$199	\$3,331
20	Total Expenses	\$210,735	-\$584	\$210,152
21	Allowance for Funds Used During Construction	\$0	\$0	\$0
22	Total Operating Income	\$35,241	\$584	\$35,825
23	Rate Base	\$676,917	-\$4,681	\$672,236
24	Required Operating Income	\$49,753	-\$411	\$49,342
25	Operating Income	\$35,241	\$584	\$35,825
26	Income Deficiency	\$14,512	-\$995	\$13,517
27	Revenue Deficiency	\$19,197	-\$1,317	\$17,880

Line No.	NSPM - 11 Bridge by Report Label	Rebuttal Adjustments				
		Request as Filed	AGIS Capital	AGIS O&M	FERC Audit Adj	RER PTC Amort
1						
2	Plant as booked					
3	Production	885,937				
4	Transmission	240,321				
5	Distribution	213,025				
6	General	72,035	(3,675)		(0)	
7	Common	60,477	(136)		(341)	
8	Total Utility Plant in Service	1,471,794	(3,811)		(342)	
9						
10	Reserve for Depreciation					
11	Production	471,529				
12	Transmission	60,624				
13	Distribution	80,327				
14	General	36,969	(475)		(0)	
15	Common	28,392	(13)		(193)	
16	Total Reserve for Depreciation	677,840	(488)		(193)	
17						
18	Net Utility Plant					
19	Production	414,408				
20	Transmission	179,697				
21	Distribution	132,698				
22	General	35,066	(3,200)		(0)	
23	Common	32,085	(123)		(148)	
24	Total Utility Plant in Service	793,954	(3,323)		(148)	
25						
26	Utility Plant Held for Future Use					
27						
28	Construction Work in Progress	1,914				
29						
30	Less: Accumulated Deferred Income Taxes	147,086	(200)		(33)	
31						
32	Other Rate Base Items					
33	Cash Working Capital	(7,100)				
34	Materials and Supplies	10,807				
35	Fuel Inventory	6,579				
36	Non Plant Assets and Liabilities	8,415				
37	Customer Advances	(62)				
38	Customer Deposits	(71)				
39	Prepayments	5,160				
40	Regulatory Amortizations	4,409				(268)
41	Total Other Rate Base	28,135				(268)
42						
43	Total Average Rate Base	676,917	(3,123)		(115)	(268)

Line No.	NSPM - 11 Bridge by Report Label	1			2			3			4			5			6			7			8		
		Request as Filed	AGIS Capital	AGIS O&M	FERC Audit Adj	RER PTC Amort	Secondary Calculations	Change in Cost of Capital	Total Rebuttal Position																
1	Operating Revenues																								
2	Retail Revenue	206,416																					206,416		
3	Other Operating	39,560																					39,560		
4	Total Revenue	245,977																					245,977		
5	Expenses																								
7	Operating Expenses																								
8	Fuel & Purchased Energy	53,351																					53,351		
9	Power Production	46,186																					46,186		
10	Transmission	17,569																					17,569		
11	Distribution	8,529		(770)																			7,759		
12	Customer Accounting	4,008		(110)																			3,898		
13	Customer Service and Information	284																					284		
14	Sales, Econ Dev, & Other	119																					119		
15	Administrative and General	16,782																					16,782		
16	Total Operating Expenses	146,828		(880)																			145,948		
17																									
18	Depreciation	54,544	(406)																				54,105		
19	Amortization	6,232						535															6,767		
20																									
21	Taxes																								
22	Property	11,495																					11,495		
23	Deferred Income Tax and ITC	(7,433)	(179)					1															(7,569)		
24	Federal and State Income Tax	(2,962)	259	215				9	(129)														(2,627)		
25	Payroll and Other	2,032																					2,032		
26	Total Taxes	3,132	80	215				10	(129)														3,331		
27																									
28	Total Expenses	210,735	(326)	(665)				(22)	406														210,152		
29																									
30	Allowance for Funds Used During Construction																								
31																									
32	Net Income	35,241	326	665	22	(406)	(9)	(15)															35,825		
33																									
34	Calculation of Revenue Requirements																								
35	Rate Base	676,917	(3,123)																				672,236		
36	Required Operating Income	49,753	(222)					(8)	(19)														49,342		
37	Operating Income	35,241	326	665	22	(406)	(8)	(15)															35,825		
38	Income Deficiency	14,512	(548)	(665)	(31)	387	(83)	(56)															13,517		
39	Revenue Deficiency	19,197	(725)	(880)	(40)	512	(109)	(74)															17,880		

Line No.	NSPM - 11 Bridge by Report Label	14	15	16	17	18	19	20	21	22	23	24	25
		ND RTF Amortization	Nonplant and Other Rate Base	O&M 3 Yr Normalization	Advertising, Association Dues, Customer Deposits	Other Revenue 3 Year Average	Payroll Tax	PI EPU Recovery	Rate Case Expenses	Sherco 1&2 Depreciation	Secondary Calculations	Change in Cost of Capital	Total
45	Operating Revenues												
46	Retail Revenue					310				(520)			206,416
47	Other Operating					310				(520)			39,321
48	Total Revenue												245,738
49													
50	Expenses												
51	Operating Expenses												
53	Fuel & Purchased Energy												53,351
54	Power Production				(75)								44,421
55	Transmission			(484)									16,963
56	Distribution			(145)									6,578
57	Customer Accounting			(208)									3,682
58	Customer Service and Information			31									315
59	Sales, Econ Dev, & Other												16
60	Administrative and General			(138)	(52)								15,553
61	Total Operating Expenses			(1,019)	(52)								140,880
62													
63	Depreciation									(3,488)			50,137
64	Amortization	(184)						(308)	(60)				5,659
65													
66	Taxes												
67	Property												
68	Deferred Income Tax and ITC		(11)					112		980	(1,881)		11,477
69	Federal and State Income Tax	45	17	249	13	76	45	12	15	(133)	1,584	(211)	(8,858)
70	Payroll and Other						(185)						1,134
71	Total Taxes	45	6	249	13	76	(140)	124	15	848	(297)	(211)	1,846
72													5,600
73	Total Expenses	(139)	6	(770)	(39)	76	(140)	(184)	(45)	(2,640)	(297)	(211)	202,275
74													
75	Allowance for Funds Used During Construction												
76													
77	Net Income	139	(6)	770	39	235	140	184	45	2,121	297	211	43,462
78													
79	Calculation of Revenue Requirements												
80	Rate Base		(1,531)					(2,515)		1,254	704		665,665
81	Required Operating Income		(113)					(185)		92	54	(3,530)	45,398
82	Operating Income	139	(6)	770	39	235	140	184	45	2,121	299	211	43,462
83	Income Deficiency	(139)	(106)	(770)	(39)	(235)	(140)	(369)	(45)	(2,029)	(245)	(3,741)	1,936
84	Revenue Deficiency	(184)	(141)	(1,019)	(52)	(310)	(185)	(488)	(60)	(2,683)	(324)	(4,949)	2,561

(1) Reflects the average balance of the 2021 capital add

	2018	2019	2020	2021	Three Year Normalization	Proposed Labor Adjustment	Proposed O&M Normalization	Non-Labor Benefits	Double Normalized
Power Production									
Non-Benefit Labor in Production - Variable	237,469	311,943	255,717	246,882	268,377	21,495			(21,495)
Non-Benefit Labor - Other Production	14,199,676	14,888,813	14,218,316	14,605,658	14,435,601	(170,056)			
Non-Benefit Labor - All Production	14,437,145	15,200,756	14,474,033	14,852,540	14,703,978	(148,562)			
Total Production - Variable	508,572	591,574	356,847	510,248	485,664		(24,584)		
All Other	25,375,872	26,214,323	26,498,659	30,138,067					
Total Power Production	40,321,589	42,006,653	41,329,539	45,500,855					
Regional Markets									
Non-Benefit Labor	13,949	14,624	17,055	17,952	15,209	(2,742)			2,742
All Other	611,787	651,974	651,737	667,236					
Total Regional Markets	625,736	666,598	668,792	685,188	653,708		(31,479)		
Transmission O&M									
Non-Benefit Labor	1,002,761	1,127,307	1,108,571	1,201,224	1,079,546	(121,678)			121,678
All Other	7,987,627	8,815,525	8,595,055	8,950,321					
Total Transmission Non-Interchange	8,990,388	9,942,832	9,703,626	10,151,545	9,545,615		(605,930)		
Transmission Interchange	5,601,603	7,269,703	7,048,871	7,417,449					
Total Transmission	14,591,991	17,212,535	16,752,497	17,568,994					
Distribution									
Non-Benefit Labor less AGIS and Border Allocator	3,391,508	3,295,872	2,890,754	2,937,391	3,192,711	255,320			284,660
AGIS Labor				284,660		(284,660)			
Border Allocator Labor	3,047	52,200	611,945	1,218,940	222,397	(996,543)			996,543
Non-Benefit Labor - Distribution	3,394,555	3,348,072	3,502,699	4,440,991	3,415,109	(1,025,883)			
Border Allocator Non-Labor	131,310	27,876	356,017	601,366					
O&M Expense Border Allocator	134,357	80,076	967,961	1,820,306	394,132		(1,426,174)		
All Other	3,144,907	3,152,020	3,087,483	3,486,823					
Total Distribution	6,670,772	6,527,969	6,946,198	8,529,180					

	2018	2019	2020	2021	Three Year Normalization	Proposed Labor Adjustment	Proposed O&M Normalization	Non-Labor Benefits	Double Normalized
Customer Accounts & Customer Service									
Non-Benefit Labor less AGIS	819,630	911,665	819,897	801,220	850,397	49,178			
AGIS Labor	-	-	-	67,024	-	(67,024)			67,024
Non-Benefit Labor - Customer Accounts & Customer Service	819,630	911,665	819,897	868,243	850,397	(17,846)			
O&M Expense Bad Debt Allocator - Cust Accts	-	669,635	1,217,760	1,145,546	629,132		(516,415)		
Bad Debt Allocator with 2018 Bad Debt	724,599	669,635	1,217,760	1,145,546	870,665		(274,882)		
Non-Labor Expense Customer Allocator - Cust Accts	877,376	886,600	938,573	993,976			(241,533)		241,533
Customer Information Non-Labor	234,673	306,914	202,900	265,717					
Customer Information	261,459	424,778	259,856	284,060	315,364		31,304		
Customer Sales Non-Labor	3	2,917	177,225	118,845					
Customer Sales	4	2,917	203,163	118,859					
All Other	985,682	1,028,625	1,027,748	1,018,749					
Total Customer Categories	3,641,964	3,806,355	4,384,103	4,411,076					
A&G									
Non-Benefit Labor	3,889,278	4,153,367	4,675,247	5,009,357	4,239,297	(770,060)			770,060
Non-Labor Benefits	8,962,987	9,017,586	8,663,198	8,084,701	8,881,257			796,556	(796,556)
All Other	3,114,132	1,958,203	2,962,295	3,687,974					
Total A&G	15,966,396	15,129,156	16,300,739	16,782,031	15,798,764		(908,384)		
Total O&M Expenses Excluding Fuel									
	84,818,448	85,349,267	86,381,868	93,477,324		(2,086,770)	(3,481,662)	796,556	1,666,188
									Total amount double normalized 2,462,744
									Employee Expense and SERP double normalized amount (796,556)
									Double normalized excluding EER and SERP 1,666,188