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

114 PU-20-441 Filed 06/01/2021 Pages: 57
Prefiled Rebuttal Testimony of Benjamin Halama - redacted
Northern States Power Company
David Sederquist

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Schedules

I. INTRODUCTION

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.

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

A. Yes, they were.

II. SUMMARY AND ORGANIZATION

Q. PLEASE PROVIDE A SUMMARY OF YOUR REBUTTAL TESTIMONY

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

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

The overall cost of service is presented in Exhibit___(BCH-3), Schedule 1, 2021 Test Year Rebuttal Cost of Service Study. Comparisons between the detailed Income Statement in our revised March 26, 2021 Notice of Change in Rates and the Company's proposed Rebuttal request are included in Exhibit___(BCH-3), Schedule 2. Each of the Company's proposed Rebuttal adjustments is included in Exhibit___(BCH-3), Schedule 3 and Exhibit___(BCH-3), Schedule 4, which bridges our original Application to our Rebuttal request and shows the resulting impact on rate base and operating income, respectively. My calculation of Mr. Mugrace's proposal are provided in BCH-3 Schedule 5, 2021 Mugrace Corrected Bridge Schedule.

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

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

Q. HOW HAVE YOU ORGANIZED YOUR REBUTTAL TESTIMONY?

A. My Rebuttal Testimony is organized as follows:

I. Introduction
II. Summary and Organization
III. Advocacy Staff Adjustments Accepted
    A. AGIS Deferral
IV. Advocacy Staff Adjustments Opposed
    A. Historical Normalization
    B. Sherco 1&2 Depreciation
    C. PI EPU Project
    D. Depreciation Study: TD&G
    E. 187 Solar
    F. Aviation

III. ADVOCACY STAFF ADJUSTMENTS ACCEPTED

A. AGIS Deferral

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

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

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

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

IV. ADVOCACY STAFF ADJUSTMENTS OPPOSED

A. Historical Normalization

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

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

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

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

Q. WHY IS A FUTURE TEST YEAR APPROPRIATE?

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

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

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[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).

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

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

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

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

1. O&M Normalization

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

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

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

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

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

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

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

A. Not in sufficient detail to justify his approach. Mr. Mugrace merely uses a recurring justification that these costs and revenues can "fluctuate and vary from year to year," and in some cases the balances during the 2018-2020 period appear to be "abnormal and irregular" compared to the Company's proposed 2021 test year. As a result, Mr. Mugrace argues that the use of a three-year average provides a smoothing of the costs and revenues.[3]

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

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

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

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

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

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

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

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

Q. WOULD NORMALIZATION EVER BE APPROPRIATE?

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

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

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

Table 1

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

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%)**

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

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

Q. PLEASE PROVIDE AN EXAMPLE OF A HISTORICAL ANOMALY.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

> <u>A public utility, at its option, may use any one of the following twelve-month periods as its test year for rate filings with the commission:</u>
>
> a. A historical test year, which may be either <u>the latest twelve-month period</u> for which actual data is available at the time of filing new schedules or the latest calendar or fiscal year for

> which actual data is available at the time of filing new schedules.
>
> b. A current test year, which is <u>any consecutive twelve-month period</u> ending not later than twelve months after the date new schedules are filed. A public utility selecting a current test year also shall file data for the twelve-month period immediately preceding the current test year selected and that period is the "historical period" for the public utility.
>
> c. A future test year, <u>which is any consecutive twelve-month period</u> ending no later than twenty-four months after the date new schedules are filed. A public utility selecting a future test year must file data for the twelve consecutive months immediately preceding the future test year and that period is the "current period" for the public utility. <u>(Emphasis added.)</u>

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

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

A. No. As discussed above, I believe the normalization adjustments proposed by Mr. Mugrace are inappropriate for at least three reasons. First, adjusting sub-sets of O&M to a normalized historical level does not allow for changes in operations and expense types. Second, the Company doesn't manage its business at the jurisdictional allocator level, but rather as a holistic entity. Third, the data does not support the need for normalization. For these reasons, I believe the Commission should not adopt Mr. Mugrace's recommended normalization adjustments.

2. Labor Normalization and Secondary Normalization Adjustments

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

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

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

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

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

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

Q. HOW IS MR. MUGRACE'S DUPLICATIVE?

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

Table 2

Transmission O&M Normalization Example

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

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

Q. DOES THIS DOUBLE NORMALIZATION EXIST IN OTHER ADJUSTMENTS?

A. Yes. In the adjustments to Employee Expense and Pension Non-Qualified SERP, Mr. Mugrace is again using a three-year average to determine non-labor benefits. As I explained previously, a three-year historical average is not an appropriate methodology for determining test year expenses. Non-labor is a sub-set of total O&M expenses, so increasing O&M to reflect this normalization is also a double adjustment of the same costs. As shown in Schedule 6, I calculate a total of $0.797 million in duplicative adjustments increasing the 2021 test year COSS.

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

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

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

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

Q. DO YOU AGREE THAT THIS ADJUSTMENT IS APPROPRIATE?

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

3. Normalization Conclusion

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

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

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

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

B. Sherco 1 & 2 Depreciation

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

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

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

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

Q. DO YOU AGREE THAT THIS ADJUSTMENT IS APPROPRIATE?

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

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

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

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

Q. WAS THIS ADJUSTMENT CALCULATED APPROPRIATELY?

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

Q. DO YOU AGREE THAT THIS ADJUSTMENT IS APPROPRIATE?

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

D. Depreciation Study: TD&G

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

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

Q. DO YOU AGREE THAT THIS ADJUSTMENT IS APPROPRIATE?

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

E. 187 Solar

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

A. Mr. Mugrace recommends removing the **[TRADE SECRET DATA BEGINS TRADE SECRET DATA ENDS]** in Fuel and Purchased Energy costs associated with the 187 MW Solar Portfolio from the 2021 test year COSS. Mr. Mugrace argues that these costs should not be recovered because the Commission initially denied an Advance Determination of Prudence (ADP) for the 187 MW Solar Portfolio in Case No. PU-14-810.

Q. WAS THIS ADJUSTMENT CALCULATED CORRECTLY?

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

Q. PLEASE EXPAND ON YOUR ANSWER?

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

F. Aviation

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

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

Q. DO YOU AGREE THAT THIS ADJUSTMENT IS APPROPRIATE?

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

G. Donations and Chamber of Commerce Dues

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

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

Q. DOES THE COMPANY AGREE WITH THIS ADJUSTMENT?

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

H. Economic Development Donations

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

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

Q. DOES THE COMPANY AGREE WITH THAT ADJUSTMENT?

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

I. Incentive Compensation

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

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

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

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

Q. DO YOU AGREE THAT THIS ADJUSTMENT IS APPROPRIATE?

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

J. Income Tax Tracker

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

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

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

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

Q. DO YOU AGREE THAT THIS ADJUSTMENT IS APPROPRIATE?

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

K. Rate Case Expenses

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

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

Q. DO YOU AGREE THAT THIS ADJUSTMENT IS APPROPRIATE?

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

L. Jeffers Wind and Community Wind North

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

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

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

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

Q. DO YOU AGREE THAT THIS ADJUSTMENT IS APPROPRIATE?

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

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

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

M. Mankato Energy Center II PPA

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

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

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

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

Q. DO YOU AGREE THAT THIS ADJUSTMENT IS APPROPRIATE?

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

N. ND RTF Amortization

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

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

Q. DO YOU AGREE THAT THIS ADJUSTMENT IS APPROPRIATE?

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

O. Non-plant and Other Rate Base

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

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

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

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

Q. DO YOU AGREE THAT THIS ADJUSTMENT IS APPROPRIATE?

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

P. Advertising, Association Dues, and Customer Deposits

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

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

Q. DO YOU AGREE THAT THIS ADJUSTMENT IS APPROPRIATE?

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

Company must "identify these costs more precisely." The Company has properly identified these costs and as a result, I am maintaining the proposed Advertising and Association Dues Expenses.

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

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

Q. Payroll Tax

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

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

Q. IS THIS ADJUSTMENT APPROPRIATE?

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

V. COMPANY'S PROPOSED ADJUSTMENTS

A. FERC Audit

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

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

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

B. RER PTC Amortization

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

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

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

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

VI. SECONDARY CALCULATIONS

A. ADIT Prorate – IRS Required

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

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

This secondary calculation limits the ADIT deduction from rate base by applying the IRS defined prorate method to only the forecast entries to this balance. As noted in my direct testimony on page 70, we inadvertently used a prorate factor in our model that created a double average. This has been corrected in the 2021 Rebuttal test year COSS.

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

B. Cash Working Capital

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

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

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

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

C. Deferred Tax Credits

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

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

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

D. Change in Cost of Capital

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

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

E. Federal and State Income Taxes

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

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

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

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

1) The proposed deficiency of $3.590 million is not included in the calculation of state and federal income taxes.
2) The proposed plant adjustment of $17.912 million is used as the adjustment for tax depreciation. The actual tax depreciation based on the proposed removal of PI EPU, Jeffers and Community Wind North and AGIS is $3.106 million.
3) The weighted cost of debt used does not match the proposed weighted average cost of debt.
4) State and federal income tax credits were not utilized as applicable.

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

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

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

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

F. Interest Synchronization

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

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

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

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

VII. CONCLUSION

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS TO THE COMMISSION.

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

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

STATE OF NORTH DAKOTA
BEFORE THE
PUBLIC SERVICE COMMISSION

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

AFFIDAVIT OF
Benjamin C. Halama

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

Benjamin C. Halama

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

Notary Public
My Commission Expires: 1/31/2025

STEVEN DELMONT SPIESS
NOTARY PUBLIC
MINNESOTA
My Commission Expires Jan. 31, 2025

NSPM - 00 Complete Revenue Requirements by Jurisdiction, Yr 2 - DRAFT	Dec - 2021		
	Total	ND Electric	Other
Composite Income Tax Rate			
State Tax Rate	4.31%	4.31%	4.31%
Federal Statuatory Tax Rate	21.00%	21.00%	21.00%
Federal Effective Tax Rate	20.09%	20.09%	20.09%
Composite Tax Rate	**24.40%**	**24.40%**	**24.40%**
Revenue Conversion Factor (1/(1--Composite Tax Rate))	1.322837	1.322837	1.322837
Weighted Cost of Capital			
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%
Weighted Cost of Equity	5.36%	5.36%	5.36%
Required Rate of Return	**7.34%**	**7.34%**	**7.34%**
Rate Base			
Plant Investment	24,859,038,913	1,467,641,324	23,391,397,589
Depreciation Reserve	11,356,647,786	677,159,331	10,679,488,455
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	(492,192,061)	(36,499,165)	(455,692,896)
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)
Prepaids and Other	80,616,733	5,159,576	75,457,157
Regulatory Amortizations	90,887,753	4,140,882	86,746,871
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**
Operating Revenues			
Retail	3,532,781,563	206,416,272	3,326,365,292
Interdepartmental	455,964		455,964
Other Operating Rev - Non-Retail	768,001,918	39,560,502	728,441,416
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			
Purchased Energy - Windsource	6,003,946	0	6,003,946
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
Production - Purchased Demand	160,569,589	9,827,919	150,741,670
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
Administrative & General	264,285,526	16,782,031	247,503,495
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
Taxes Other than Income	173,619,078	5,957,853	167,661,226
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
Other Book Additions	5,887,911	581,747	5,306,165
Total Tax Additions	990,745,570	57,629,071	933,116,500
Tax Deductions			
Total Rate Base	11,317,099,394	672,235,766	10,644,863,628
Weighted Cost of Debt	1.98%	1.98%	1.98%
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
Other Tax / Book Timing Differences	(1,864,323)	(282,512)	(1,581,811)
Total Tax Deductions	**1,777,710,522**	**102,925,436**	**1,674,785,086**
State Taxes			
State Taxable Income	(295,477,622)	(12,098,102)	(283,379,520)
State Income Tax Rate	4.31%	4.31%	4.31%
State Taxes before Credits	(12,735,085)	(521,428)	(12,213,657)
Less State Tax Credits applied	(1,113,793)	(17,093)	(1,096,700)
Total State Income Taxes	(13,848,878)	(538,521)	(13,310,357)
Federal Taxes			
Federal Sec 199 Production Deduction			
Federal Taxable Income	(281,628,743)	(11,559,580)	(270,069,163)
Federal Income Tax Rate	21.00%	21.00%	21.00%
Federal Tax before Credits	(59,142,036)	(2,427,512)	(56,714,524)
Less Federal Tax Credits	(6,314,652)	338,807	(6,653,459)
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**
Rate of Return (ROR)			
Total Operating Income	570,792,896	35,825,490	534,967,406
Total Rate Base	11,317,099,394	672,235,766	10,644,863,628
ROR (Operating Income / Rate Base)	5.04%	5.33%	5.03%
Return on Equity (ROE)			

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
Equity Rate Base (Rate Base * Equity Ratio)	5,941,477,182	352,923,777	5,588,553,405
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
Net Operating Income	570,792,896	35,825,490	534,967,406
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
Revenue Deficiency	343,781,805	17,880,280	325,901,526
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
	Operating Revenues			
1	Retail	$206,416	$0	$206,416
2	Other Operating	$39,560	$0	$39,560
3	Total Operating Revenues	$245,977	$0	$245,977
	Expenses			
	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	$16,782	$0	$16,782
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	$2,032	$0	$2,032
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

Northern States Power Company
Electric Utility - State of North Dakota
Test Year Ending December 31, 2021
Rebuttal Bridge Schedule - Rate Base

		1	2	3	4	5
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	Net 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)

		1	2	3	4	5	6	7	8
			Rebuttal Adjustments						
Line No.	NSPM - 11 Bridge by Report Label	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									
6	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)		(32)				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		42		(7,569)
24	Federal and State Income Tax	(2,962)	259	215	9	(129)	(33)	15	(2,627)
25	Payroll and Other	2,032							2,032
26	Total Taxes	3,132	80	215	10	(129)	9	15	3,331
27									
28	Total Expenses	210,735	(326)	(665)	(22)	406	9	15	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)		(115)	(268)	(1,175)		672,236
36	Required Operating Income	49,753	(222)		(8)	(19)	(91)	(71)	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**

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Northern States Power Company
Electric Utility - State of North Dakota
TY Ending Dec 31, 2021
Mugrace Corrected Bridge Schedule

		1	2	3	4	5	6	7	8	9	10	11	12	13
													Staff Proposed Corrected	
Line No.	NSPM - 11 Bridge by Report Label	Request as Filed	AGIS Capital (1)	AGIS O&M	Aviation	Depreciation Study: TD&G	Donations	Dues: Chamber of Commerce	Economic Development Donations	Incentive Pay	Income Tax Tracker	Labor 3 Yr Normalization	Jeffers Wind and Community Wind North	Mankato Energy
1														
2	Plant as booked													
3	Production	885,937											(7,855)	
4	Transmission	240,321												
5	Distribution	213,025												
6	General	72,035	(2,181)											
7	Common	60,477	(51)											
8	Total Utility Plant in Service	1,471,794	(2,232)										(7,855)	
9														
10	Reserve for Depreciation													
11	Production	471,529											(241)	
12	Transmission	60,624				(107)								
13	Distribution	80,327				(101)								
14	General	36,969	(82)											
15	Common	28,392	(0)											
16	Total Reserve for Depreciation	677,840	(82)			(207)							(241)	
17														
18	Net Utility Plant													
19	Production	414,408											(7,614)	
20	Transmission	179,697				107								
21	Distribution	132,698				101								
22	General	35,066	(2,099)											
23	Common	32,085	(51)											
24	Net Utility Plant in Service	793,954	(2,150)			207							(7,614)	
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	(105)			58							(703)	
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									(357)			
41	Total Other Rate Base	28,135									(357)			
42														
43	Total Average Rate Base	676,917	(2,045)			149					(357)		(6,911)	
44														

Northern States Power Company
Electric Utility - State of North Dakota
TY Ending Dec 31, 2021
Mugrace Corrected Bridge Schedule

		14	15	16	17	18	19	20	21	22	23	24	25
Line No.	NSPM - 11 Bridge by Report Label	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
1													
2	Plant as booked												
3	Production												878,082
4	Transmission												240,321
5	Distribution												213,025
6	General												69,854
7	Common												60,426
8	Total Utility Plant in Service												1,461,707
9													
10	Reserve for Depreciation												
11	Production									(1,744)			469,544
12	Transmission												60,517
13	Distribution												80,226
14	General												36,887
15	Common												28,392
16	Total Reserve for Depreciation									(1,744)			675,566
17													
18	Net Utility Plant												
19	Production									1,744			408,538
20	Transmission												179,804
21	Distribution												132,798
22	General												32,967
23	Common												32,034
24	Net Utility Plant in Service									1,744			786,141
25													
26	Utility Plant Held for Future Use												
27													
28	Construction Work in Progress												1,914
29													
30	Less: Accumulated Deferred Income Taxes		(599)					(1,440)		490	(976)		143,812
31													
32	Other Rate Base Items												
33	Cash Working Capital										(272)		(7,372)
34	Materials and Supplies												10,807
35	Fuel Inventory												6,579
36	Non Plant Assets and Liabilities		(2,129)										6,286
37	Customer Advances												(62)
38	Customer Deposits												(71)
39	Prepayments												5,160
40	Regulatory Amortizations							(3,955)					96
41	Total Other Rate Base		(2,129)					(3,955)			(272)		21,421
42													
43	Total Average Rate Base		(1,531)					(2,515)		1,254	704		665,665
44													

Case No. PU-20-441
Exhibit___(BCH-3), Schedule 5

Mugrace Corrected Bridge Schedule

		1	2	3	4	5	6	7	8	9	10	11	12	13
			Staff Proposed Corrected											
Line No.	NSPM - 11 Bridge by Report Label	Request as Filed	AGIS Capital (1)	AGIS O&M	Aviation	Depreciation Study: TD&G	Donations	Dues: Chamber of Commerce	Economic Development Donations	Incentive Pay	Income Tax Tracker	Labor 3 Yr Normalization	Jeffers Wind and Community Wind North	Mankato Energy
45	Operating Revenues													
46	Retail Revenue	206,416												
47	Other Operating	39,560				(32)								
48	Total Revenue	245,977				(32)								
49														
50	Expenses													
51	Operating Expenses													
53	Fuel & Purchased Energy	53,351												
54	Power Production	46,186										(151)	(114)	(1,425)
55	Transmission	17,569										(122)		
56	Distribution	8,529		(780)								(1,026)		
57	Customer Accounting	4,008		(100)								(18)		
58	Customer Service and Information	284												
59	Sales, Econ Dev, & Other	119							(103)					
60	Administrative and General	16,782			(98)		(68)	(20)		(81)		(770)		
61	Total Operating Expenses	146,828		(880)	(98)		(68)	(20)	(103)	(81)		(2,087)	(114)	(1,425)
62														
63	Depreciation	54,544	(164)			(414)							(341)	
64	Amortization	6,232									(20)			
65														
66	Taxes													
67	Property	11,495											(18)	
68	Deferred Income Tax and ITC	(7,433)	(132)			116							(610)	
69	Federal and State Income Tax	(2,962)	154	215	24	(8)	17	5	25	20	7	509	1,070	348
70	Payroll and Other	2,032			(1)									
71	Total Taxes	3,132	22	215	23	108	17	5	25	20	7	509	442	348
72														
73	Total Expenses	210,735	(142)	(665)	(75)	(306)	(52)	(15)	(78)	(61)	(14)	(1,577)	(13)	(1,077)
74														
75	Allowance for Funds Used During Construction													
76														
77	Net Income	35,241	142	665	75	275	52	15	78	61	14	1,577	13	1,077
78														
79	Calculation of Revenue Requirements													
80	Rate Base	676,917	(2,045)			149					(357)		(6,911)	
81	Required Operating Income	49,753	(150)			11					(26)		(508)	
82	Operating Income	35,241	142	665	75	275	52	15	78	61	14	1,577	13	1,077
83	Income Deficiency	14,512	(292)	(665)	(75)	(264)	(52)	(15)	(78)	(61)	(40)	(1,577)	(521)	(1,077)
84	**Revenue Deficiency**	**19,197**	**(386)**	**(880)**	**(99)**	**(349)**	**(68)**	**(20)**	**(103)**	**(81)**	**(53)**	**(2,087)**	**(689)**	**(1,425)**

(1) Reflects the average balance of the 2021 capital additions Mugrace proposed in his testimony.

Northern States Power Company
Electric Utility - State of North Dakota
TY Ending Dec 31, 2021
Mugrace Corrected Bridge Schedule

		14	15	16	17	18	19	20	21	22	23	24	25
Line No.	NSPM - 11 Bridge by Report Label	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												206,416
47	Other Operating					310				(520)			39,321
48	Total Revenue					310				(520)			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												11,477
68	Deferred Income Tax and ITC		(11)					112		980	(1,881)		(8,858)
69	Federal and State Income Tax	45	17	249	13	76	45	12	15	(133)	1,584	(211)	1,134
70	Payroll and Other						(185)						1,846
71	Total Taxes	45	6	249	13	76	(140)	124	15	848	(297)	(211)	5,600
72													
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

Northern States Power Company
Electric Utility - State of North Dakota
TY Ending Dec 31, 2021
Mugrace Double Normalization

	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			
AGIS Labor				284,660	-	(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)		
							(241,533)		241,533
Non-Labor Expense Customer Allocator - Cust Accts	877,376	886,600	938,573	993,976					
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	81,818,448	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