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Direct Testimony and Schedules
Benjamin C. Halama

Before the Minnesota Public Utilities Commission
State of Minnesota

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

Docket No. E002/GR-20-723
Exhibit___(BCH-1)

2021 Test Year and 2022-2023 Plan Years
Overall Revenue Requirements
Rate Base
Income Statement
Rate Rider Recovery 2021-2023

November 2, 2020

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Schedules

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND TITLE.

A. My name is Benjamin C. Halama. I am Manager of Revenue Analysis for Xcel Energy Services Inc. (XES or the Service Company), the service company for Xcel Energy, Inc. and its operating company subsidiaries.

Q. PLEASE DESCRIBE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have over five years of experience at XES, supporting Northern States Power Company–Minnesota (NSPM or the Company) in the areas of regulatory accounting, financial operations, and revenue requirements. In my current role, I am responsible for the development of jurisdictional revenue requirements for all NSPM jurisdictions. My resume is attached as Exhibit___(BCH-1), Schedule 1, Resume.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. In my Direct Testimony, I support the Company's Minnesota jurisdiction electric operations cost of service, revenue requirements, and revenue deficiency for each of the three years of the Company's multi-year rate plan (MYRP), which include calendar year 2021 (the test year) and 2022 and 2023 (the plan years). Overall, the net deficiencies and retail revenue requirements for the test year and plan years are summarized in Table 1 below:

Table 1

2021-2023 Revenue Requests

Minnesota Jurisdictional Deficiency Net of Interchange ($s in millions)

MYRP Year	2021	2022	2023
Amount, cumulative	$405.8	$504.3	$597.4
Amount, incremental	$405.8	$98.5	$93.1
Average % increase, incremental *	13.2%	3.3%	3.2%

* The "average percent increase, incremental" is calculated using the annual revenue request over the forecasted present revenues in each applicable year, less prior year(s).

I provide the financial data supporting these overall revenue deficiencies for the State of Minnesota retail electric jurisdiction, including a description of cost changes, the data we provide, and our selection of the test year. Further, I present:

- our jurisdictional cost of service study and the revenue requirement effects of our utility and jurisdictional allocations; and
- our revenue requirement, including rate base and income statement components, with related adjustments and amortizations.

My testimony also supports the 2021 and 2022 requested interim rate increases discussed in the Company's Petition for Interim Rates. Company witness Mr. Gregory P. Chamberlain provides additional support for the interim rate increases proposed as a part of our MYRP, as does the Notice and Petition for Interim Rates, included in Volume 1 of our Application.

In addition, I explain our treatment of riders, and identify certain compliance requirements addressed in our general rate filing.

I relied on information provided by other Company witnesses in this proceeding to develop many of the test year revenue requirement adjustments discussed in my Direct Testimony.

Q. HOW IS THE REST OF YOUR DIRECT TESTIMONY ORGANIZED?

A. I present my testimony in the following sections:

- Section II, *Case Overview*, summarizes our jurisdictional revenue requirement for the 2021 test year and 2022-2023 plan years, and discusses the key drivers of cost increases compared to our last MYRP established in Docket No. E002/GR-15-826 (the 2016-2019 MYRP).
- Section III, *Supporting Information*, provides information related to the data provided in our application, the selection of the test year and plan years, and the jurisdictional cost of service study.
- Section IV, *Rate Base*, identifies and explains the components of rate base, and supports the reasonableness of the Company's projected 2021 test year and 2022-2023 plan years rate base.
- Section V, *Income Statement*, identifies and explains the major components of the income statement and supports the reasonableness of the Company's proposed 2021 test year and 2022-2023 plan years income statement.
- Section VI, *Utility and Jurisdictional Allocations*, explains why it is necessary for the Company to allocate costs among its affiliates and between jurisdictions, and describes the utility and jurisdictional allocators that are

used in determining the MYRP revenue requirement.

- Section VII, *Annual Adjustments to the MYRP*, presents adjustments affecting the 2021 test year and 2022-2023 plan years revenue requirements, providing both rate base and income statement impacts.
- Section VIII, *Costs Recovered in Riders*, presents our proposed treatment of costs recovered in riders during the MYRP period, providing details about which riders we propose to continue to use and costs we propose to move into base rates, coincident with the implementation of final rates.
- Section IX, *Compliance with Prior Commission Orders*, provides information related to specific requirements from prior Minnesota Public Utilities Commission (Commission) Orders that have not been addressed elsewhere in my testimony.
- Section X, *Conclusion*, summarizes our request.

Q. ARE ALL THE DOLLAR VALUES PRESENTED IN YOUR TESTIMONY JURISDICTIONALIZED TO STATE OF MINNESOTA ELECTRIC JURISDICTION?

A. While most of the dollar values presented in my testimony are jurisdictionalized to State of Minnesota Electric Jurisdiction, there are several instances where dollars are either Total Company, or net of Interchange Agreement (IA) billings to Northern States Power Company-Wisconsin (NSPW). Dollar values that are Total Company or net of Interchange Agreement billings to NSPW are labeled accordingly.

Q. DO YOU PROVIDE INFORMATION IN COMPLIANCE WITH PAST COMMISSION ORDERS AND COMPANY COMMITMENTS?

A. Yes. Throughout my testimony, I note where I am providing information related to prior Commission Orders and Company commitments. In Section IX, I provide additional information related to compliance with prior Commission Orders that have not been addressed elsewhere in my testimony.

II. CASE OVERVIEW

Q. WHAT TOPICS DO YOU DISCUSS IN THIS SECTION OF YOUR TESTIMONY?

A. In this section, I will:

- present the jurisdictional revenue requirement and revenue deficiencies for Minnesota for the 2021 test year and 2022-2023 plan years, referred to in total as the "MYRP Forecast;"
- present a summary comparison of the costs in the MYRP Forecast to the costs in the 2016-2019 MYRP approved in our last completed rate case, which include costs and changes and true-ups in each year of the MYRP; and
- provide an explanation of the primary sources of the changes in overall costs, including plant-related costs and operations and maintenance (O&M) costs.

A. MYRP Jurisdictional Revenue Requirements and Deficiencies

Q. PLEASE DESCRIBE THE BASIS OF THE COMPANY'S MYRP PROPOSAL.

A. The Company's three-year plan utilizes 2021 as the test year, with 2022 and 2023 as additional plan years developed using budgeted capital additions and budgeted O&M expenses. Also included in the proposal are impacts to other rate base items, sales adjustments, and other adjustments impacting the revenue requirements for these years, so that each year represents a cost of service approach to rate-setting for both capital and O&M.

Q. WHAT IS THE 2021 TEST YEAR JURISDICTIONAL OVERALL REVENUE REQUIREMENT AND REVENUE DEFICIENCY?

A. The overall jurisdictional revenue requirement for the 2021 test year is $3.47 billion. The 2021 test year revenue deficiency, excluding rider roll-ins, is $405.8 million. The 2021 test year revenue deficiency amount represents a 13.2 percent overall increase in retail revenues from base rates compared to projected 2021 retail revenues at present rates. A summary of the 2021 revenue deficiency (in dollars and as a percent) is provided in Exhibit___(BCH-1) Schedule 2, Summary of Revenue Requirements. The calculation of these dollar amounts is provided in Exhibit___(BCH-1) Schedule 3, Cost of Service Study Summary.

Q. WHAT ARE THE OVERALL REVENUE REQUIREMENT AND REVENUE DEFICIENCIES FOR THE 2022 THROUGH 2023 PLAN YEARS?

A. The overall jurisdictional revenue requirements for the 2022 and 2023 plan years are $3.56 billion and $3.63 billion, respectively. The 2022 and 2023 revenue deficiencies, excluding rider roll-ins, are $504.3 million and $597.4 million, respectively. The overall revenue requirement request for the MYRP Forecast represents a 19.7 percent increase in retail revenues from base rates in 2023 compared to projected 2023 retail revenues at present rates. A summary of the 2022 and 2023 revenue deficiencies (in dollars and as percentages) is provided in Schedule 2, Summary of Revenue Requirements. The calculation of these dollar amounts is provided in Schedule 3, Cost of Service Study Summary.

Q. WHAT IS THE AMOUNT OF THE INTERIM RATE REVENUE DEFICIENCY IN 2021?

A. The Interim Rate Petition (Petition) supports an interim revenue deficiency based on the 2021 test year of $308.9 million, which results in a proposed interim rate increase of 10.6 percent beginning January 1, 2021.

Q. IS AN INTERIM RATE REQUEST FOR 2022 INCLUDED IN THIS FILING?

A. Yes. As discussed in the Direct Testimony of Mr. Chamberlain and in the Notice and Petition for Interim Rates, the Company is also proposing an interim rate adjustment for 2022 as part of its multi-year rate plan filing. The 2022 interim rate revenue deficiency includes an additional $96.4 million beginning on January 1, 2022, which equates to an additional interim rate increase of 3.3 percent in 2022.

Q. HOW DOES THE COMPANY CALCULATE ITS REVENUE REQUIREMENT AND REVENUE DEFICIENCY?

A. The general formula for calculation of the revenue requirement and revenue deficiency is depicted below in Table 2:

Table 2

Revenue Requirement and Revenue Deficiency

	Item	2021 Test Year Amount ($000s)	2022 Plan Year Amount ($000s)	2023 Plan Year Amount ($000s)	Exhibit__ (BCH-1), Sch. 3 Reference
	Average Rate Base	$9,950,576	$10,267,755	$10,656,235	Page 1, Line 44
multiplied by	Cost of capital	7.35%	7.34%	7.33%	Page 1, Line 20
	Operating Income Requirement	**$731,367**	**$753,653**	**$781,102**	Page 4, Line 158
	Current Retail Revenue	$3,064,643	$3,053,834	$3,031,362	Page 2, Line 47 + Line 48
plus	Current Other Revenue	$545,625	$563,137	$568,466	Page 2, Line 49
equals	Current Total Revenue	$3,610,268	$3,616,971	$3,599,829	Page 2, Line 50
minus	Operating Expenses	$2,352,958	$2,376,248	$2,399,661	Page 2, Line 74
minus	Depreciation Expense	$737,364	$778,372	$792,829	Page 2, Line 76
minus	Amortization Expense	$55,040	$51,576	$49,467	Page 2, Line 77
minus	Taxes	$51,167	$41,530	$33,557	Page 3, Line 135
plus	AFUDC	$28,498	$25,065	$31,124	Page 3, Line 140 + Line 141
equals	**Total Available for Return**	**$442,237**	**$394,310**	**$355,438**	Page 3, Line 143
	Operating Income Requirement	$731,367	$753,653	$781,102	Page 4, Line 158
minus	Total Available for Return	$442,237	$394,310	$355,438	Page 3, Line 143
equals	**Income Deficiency**	**$289,131**	**$359,343**	**$425,664**	Page 4, Line 160
multiplied by	Gross Revenue Conversion Factor	1.403351	1.403351	1.403351	Page 4, Line 162
equals	**Revenue Deficiency**	**$405,751.78**	**$504,284.32**	**$597,356.25**	Page 4, Line 163
plus	Current Retail Revenue	$3,064,643	$3,053,834	$3,031,362	Page 4, Line 166
equals	**Total Revenue Requirement**	**$3,470,395**	**$3,558,119**	**$3,628,719**	Page 4, Line 168

Q. HAS THE COMPANY PROVIDED AN EXPLANATION OF THE ASSUMPTIONS AND APPROACHES USED IN DEVELOPING THE TEST YEAR OPERATING INCOME?

A. Yes. An explanation is provided in the Financial Information section of Volume 3 (Required Information) of this Application. In addition, workpapers supporting the 2021 test year cost of service are provided in Volume 4 (MYRP Workpapers) of this Application.

Q. HOW DOES THE COMPANY TREAT CAPITAL AND O&M COSTS IN THE 2021-2023 MYRP?

A. Our proposal uses the following reasoning to develop costs:

1. Capital, capital-related, and O&M costs follow the Company's budget, except as needed to comply with prior Commission Orders or adjustments the Company is specifically proposing in this proceeding. (Capital-related consists of depreciation and allowance for funds used during construction (AFUDC) as well as the cost of capital).
2. Fuel revenues and expenses for all years of the 2021-2023 MYRP are represented in this docket at the level filed in the Company's July 31, 2020 fuel update[1] as discussed in the Company's August 11, 2019 Compliance Filing approved by the Commission in Docket No. E999/CI-03-802[2].
3. Expenses that have jurisdiction-specific regulatory accounting treatment follow that treatment. For example:

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[1] Company's July 31, 2020, Reply Comments, Docket No. E002/AA-20-417.
[2] Fuel expenses for the 2021-2023 MYRP are held flat at the filed level, but the Fuel and Purchased Energy line of the cost of service model (BCH-1 Schedule 3, row 58) fluctuates due to inclusion of fuel handling base O&M and the Benson PPA).

a. The Company amortizes nuclear fueling outage costs over the periods between outages. These costs should follow the Company's budget; and

b. Expenses related to the Company's pension and benefit costs have several regulatory adjustments based on the outcome of the Company's recent rate cases.

4. Secondary calculations necessary for a full cost of service study are based on the results of the above items. For example:

a. Cash Working Capital balance related to the revenues and expenses developed above;

b. Deferred Tax Asset balance and deferred tax expense related to a Net Operating Loss calculation; and

c. Change in debt interest expense related to the budgeted change in debt costs and the budget of rate base.

B. Case Drivers

Q. HAVE YOU PREPARED A COMPARISON OF THE COSTS IN THE MYRP FORECAST TO CURRENT RATES RESULTING FROM THE 2016-2019 MYRP?

A. Yes. I provide an explanation of the detailed case drivers of the deficiency using a comparison of the 2021 test year (including rider roll-ins) with the base rates in effect in 2019 as a result of the MYRP in Docket No. E002/GR-15-826 (the 2016-2019 MYRP).[3] My analysis also includes a comparison of years two (2022)

[3] The 2016-2019 MYRP was based on a settlement that included an illustrative rate base, plus true-ups during the MYRP period for sales forecast, property tax expense, and capital-related revenue requirements. In addition, the cost of service was updated to reflect the implications of the Tax Cuts and Jobs Act (TCJA) as a result of the Commission's findings in Docket No. E, G999/CI-17-895. Therefore, our comparison of drivers compares the base rates in effect in 2019 to the 2021 test year.

and three (2023) of the MYRP. My analysis differs from the Direct Testimony analyses of the Company's business area witnesses, who discuss costs and cost changes in more detail and in terms of actual costs and budgets (not revenue deficiencies). Therefore, my discussion of key cost drivers reflects dollar values that are, in large part, different from their discussions. In addition, I discuss these drivers at a high level, and defer to the business area witnesses to provide more detail around the activities and changes giving rise to these drivers.

Q. HAVE YOU PREPARED A SCHEDULE IDENTIFYING THE CHANGES IN THE MAJOR COST ELEMENTS SINCE THE COMPANY'S LAST ELECTRIC RATE CASE?

A. Yes. I provide Exhibit___(BCH-1), Schedule 6, Detailed Case Drivers, which provides a Summary of Major Cost Drivers (identification of case drivers for the MYRP Forecast), including details of the categories identified in Table 3 below.

Table 3

MYRP Net Incremental Deficiency ($ in millions)

	Increase (Decrease) 2021 TY to 2019 MYRP	Increase (Decrease) 2022 TY to 2021 TY	Increase (Decrease) 2023 TY to 2022 TY	3-Year MYRP
Capital and Capital Related	$399.7	$67.5	$36.8	$503.9
Amortizations	11.2	0.0	(2.1)	9.1
Taxes	(102.4)	17.9	17.8	(66.7)
Operating Expense	(17.0)	23.4	22.9	29.3
Other Margin Impacts*	114.3	(10.2)	17.7	121.8
Total Net Incremental Deficiency	$405.8	$98.5	$93.1	$597.4

*Includes settlement Other Revenue credit (revenue requirement reduction) from the 2016-2019 MYRP Rate Case as filed in indicative cost of service in Docket No. E002/GR-15-826.

In addition to the discussion in this Section, support for our proposed increase in rates for the 2021 test year is provided in the Direct Testimonies of the Company's business area witnesses and the Direct Testimony of Company witness Ms. Melissa L. Ostrom.

Q. PLEASE DESCRIBE THE REVENUE REQUIREMENT IMPACT FOR THE PRINCIPAL CHANGES IN CAPITAL AND CAPITAL RELATED COSTS.

A. Table 4 below compares the MYRP Forecast revenue requirements with the comparable revenue requirements for the 2019 MYRP, by category, for capital plant related costs as shown on Schedule 6, Detailed Case Drivers.

Table 4

Capital and Capital Related Cost Changes ($ in millions)

	Increase (Decrease) 2021 TY to 2019 MYRP	Increase (Decrease) 2022 TY to 2021 TY	Increase (Decrease) 2023 TY to 2022 TY	3-Year MYRP
Nuclear	$36.9	$5.5	$6.4	$48.8
Steam	(17.8)	3.9	(19.6)	(33.5)
Wind	156.1	(6.0)	(10.5)	139.6
All Other Production	1.3	2.7	4.7	8.7
Transmission	68.4	10.4	9.4	88.1
Distribution	33.1	24.4	24.8	82.3
General and Intangible	28.1	13.6	8.7	50.5
DTA (Federal Credits & NOL)	9.9	10.7	9.9	30.5
Other Rate Base	(0.2)	(0.3)	(0.3)	(0.8)
Cost of Capital	83.8	2.7	3.3	89.7
TOTAL Capital and Capital Related	$399.7	$67.5	$36.8	$503.9

Q. PLEASE DESCRIBE THE PRINCIPAL CHANGES IN NUCLEAR CAPITAL COSTS.

A. The MYRP Forecast revenue requirements include a $48.8 million increase in Nuclear. This increase is due to capital investments for Nuclear Fuel, Dry Cask Storage, Mandated Compliance, Reliability, and Improvements in the MYRP Forecast as well as incremental additions during the last MYRP period. Additional information regarding nuclear projects is discussed in the Direct Testimony of Company witness Mr. Peter A. Gardner.

Q. WHAT ARE THE PRINCIPAL CHANGES IN WIND CAPITAL COSTS?

A. The MYRP Forecast revenue requirements include a $139.6 million increase to Wind. This increase is due to capital investments for the Blazing Star I & II, Crowned Ridge, Mower, Jeffers, and Community Wind North Wind Farms, which are scheduled to be placed in service in 2020. In addition, we anticipate rolling into base rates the Courtenay, Foxtail, Blazing Star I and II, Lake Benton, Crowned Ridge, Jeffers, Community Wind North and Mower Wind Farms. Additional information regarding wind projects are discussed in the Direct Testimony of Company witness Ms. Kimberly A. Randolph.

Q. PLEASE DESCRIBE THE PRINCIPAL CHANGES IN TRANSMISSION CAPITAL COSTS.

A. The MYRP Forecast revenue requirements include an $88.1 million increase to Transmission. This increase is due mainly to an increase in asset health projects and the roll-in of large transmission capital projects, particularly the CapX2020 projects from the Transmission Cost Recovery (TCR) Rider. Additional information regarding transmission projects are discussed in the Direct Testimony of Company witness Mr. Ian R. Benson.

Q. PLEASE IDENTIFY THE PRINCIPAL CHANGES IN DISTRIBUTION CAPITAL COSTS.

A. The MYRP Forecast revenue requirements include an $82.3 million increase to Distribution. This increase is due to capital investments relating to expansion of Distribution's asset health programs to address the portions of our system that are closest to our customers, such as pole and underground cable replacements. This increase is also due to new business for new and expanded customer service, capacity investment for greater reliability, and required relocation projects stemming from an increased number of road construction projects. Distribution also manages work associated with the Advanced Grid Intelligence & Security (AGIS) initiative, but most AGIS costs are certified for inclusion in the TCR Rider and are not reflected in base rates in this matter. Additional information regarding distribution projects are discussed in the Direct Testimony of Company witness Ms. Kelly A. Bloch.

Q. WHAT ARE THE PRINCIPAL CHANGES IN GENERAL AND INTANGIBLE CAPITAL COSTS?

A. The MYRP Forecast revenue requirements include a $50.5 million increase to General and Intangible. This increase is due to capital investments relating to replacing aging technology, addressing evolving cyber security threats and requirements, enhancing capabilities, enhancing the customer experience, and addressing emergent demands. It also includes the internal labor AGIS costs that are not included in the TCR Rider. Additional information regarding general and intangible projects is discussed in the Direct Testimony of Company witness Mr. Wendall A. Reimer.

Q. PLEASE DESCRIBE THE PRINCIPAL CHANGES IN COST OF CAPITAL.

A. The MYRP Forecast revenue requirements include an $89.7 million increase related to changes in cost of capital. The change in cost of capital is due to a requested 10.2 percent return on equity (ROE), partially offset by a decrease in the cost of long-term debt. Company witness Ms. Sarah Soong describes the capital structure and costs of debt in her Direct Testimony. Company witness Mr. Dylan D'Ascendis of ScottMadden, Inc. discusses the Company's recommended ROE.

Q. PLEASE DESCRIBE THE PRINCIPAL CHANGES IN AMORTIZATIONS.

A. The MYRP Forecast revenue requirements include a $9.1 million increase related to amortizations. This increase is due to new amortizations for the Aurora Deferral (discussed in adjustment 9 below), Net Operating Loss (NOL) Tax Reform Regulatory Amortization (discussed in adjustment 13 below) and Income Tax Tracker Amortization (discussed in adjustment 11 below), as well as an increase in Rate Case Expense amortization (discussed in adjustment 15 below).

Q. PLEASE DESCRIBE THE PRINCIPAL CHANGES IN TAXES.

A. The MYRP Forecast revenue requirements include a $66.7 million decrease to taxes. This decrease is due to increased Production Tax Credits (PTCs) associated with new and existing wind farms being moved to base rate recovery in this case partially offset by an increase in property taxes. Additional information regarding property taxes is discussed in the Direct Testimony of Company witness Mr. Christopher A. Arend.

Q. PLEASE DESCRIBE THE PRINCIPAL CHANGES IN O&M COSTS.

A. Table 5 below compares the MYRP Forecast revenue requirements with the comparable revenue requirements for the 2019 MYRP, by category, for operating expenses as shown on Schedule 6, Detailed Case Drivers.

Table 5

O&M Cost Changes ($ in millions)

	Increase (Decrease) 2021 TY to 2019 MYRP	Increase (Decrease) 2022 TY to 2021 TY	Increase (Decrease) 2023 TY to 2022 TY	3-Year MYRP
Nuclear	($61.4)	$1.2	$2.5	($57.6)
Steam	(42.1)	(3.5)	5.8	(39.8)
Wind	23.5	0.7	0.1	24.3
Purchased Demand	12.1	2.8	0.1	15.0
All Other Production	19.5	1.3	10.9	31.7
Transmission	29.1	5.0	3.0	37.2
Transmission Interchange	(25.6)	6.9	4.4	(14.3)
Distribution	16.2	5.6	2.7	24.5
Regional Markets	2.4	(0.2)	0.4	2.6
Customer Accounting / Info / Service	8.4	(6.3)	(10.6)	(8.5)
A&G	1.0	9.9	3.3	14.2
TOTAL O&M	($17.0)	$23.4	$22.9	$29.3

Q. WHAT ARE THE REASONS FOR THE DECREASE IN NUCLEAR OPERATIONS OPERATING EXPENSE?

A. The MYRP Forecast revenue requirements include a $57.6 million decrease in nuclear operating expenses. This decrease is due to reductions in contractor costs and materials, as well as reductions in outage costs in 2019 and 2020, which flow through to subsequent years through the deferral and amortization of these costs. Additional information regarding nuclear operating expenses is discussed by Mr. Gardner.

Q. WHAT ARE THE REASONS FOR THE DECREASE IN STEAM OPERATING EXPENSE?

A. The MYRP Forecast revenue requirements include a $39.8 million decrease in steam operating expenses. This decrease is due to reduced overhaul and project investments as several units approach retirement. Additional information regarding steam operating expenses is discussed by Ms. Randolph.

Q. WHAT ARE THE REASONS FOR THE INCREASE IN WIND OPERATING EXPENSE?

A. The MYRP Forecast revenue requirements include a $24.3 million increase in wind operating expenses. This increase is due to the additional operating expense associated with new wind farms that have been or will be added to our generation portfolio, as discussed by Ms. Randolph.

Q. WHAT ARE THE REASONS FOR THE INCREASE IN PURCHASED DEMAND OPERATING EXPENSE?

A. The MYRP Forecast revenue requirements include a $15 million increase in purchased demand operating expenses. The increase is due to a known increase in overall contracted capacity due to a new contract with Manitoba Hydro that increased the capacity purchases by 125 MW starting in 2021.

Q. WHAT ARE THE REASONS FOR THE INCREASE IN ALL OTHER PRODUCTION OPERATING EXPENSE?

A. The MYRP Forecast revenue requirements include a $31.7 million increase in all other production operating expenses. This increase is due to changes in the NSPW Interchange Agreement bill to NSPM, primarily due to increased capital investment. A significant portion of the increase in 2023 is due to the addition of a solar farm expected to be in-service in late 2022.

Q. WHAT ARE THE REASONS FOR THE INCREASE IN TRANSMISSION OPERATING EXPENSE?

A. The MYRP Forecast revenue requirements include a $37.2 million increase in Transmission operating expenses. This increase is primarily due to a change in the TCR Removal adjustment compared to the 2016-2019 MYRP. In the 2021-2023 MYRP, the adjustment removes the Minnesota jurisdictional share (net of IA) of the costs including the Regional Expansion Criteria and Benefits (RECB) expense; however, in the 2016-2019 MYRP, the rider removal removed the gross RECB expense and included an offset in other revenue for the IA portion. The change in methodology was made in the 2021-2023 MYRP to better align with the presentation of the Cost of Service Study (COSS). The remaining increase is due to additional network transmission costs, Midcontinent Independent System Operator (MISO) network interconnection upgrades and higher MISO administrative charges.

Q. WHAT ARE THE REASONS FOR THE DECREASE IN TRANSMISSION INTERCHANGE OPERATING EXPENSE?

A. The MYRP Forecast revenue requirements include a $14.3 million decrease in transmission interchange operating expenses. This decrease is due to lower transmission rate base and a decrease in the Interchange ROE.

Q. WHAT ARE THE REASONS FOR THE INCREASE IN DISTRIBUTION OPERATING EXPENSE?

A. The MYRP Forecast revenue requirements include a $24.5 million increase in distribution operating expenses. This increase is due to the need to catch-up on Vegetation Management work that was deferred in 2020, increased O&M to implement the AGIS initiative, and increases in Asset Health and Reliability projects, as discussed in the Direct Testimony of Ms. Bloch.

Q. WHAT ARE THE REASONS FOR THE INCREASE IN ADMINISTRATIVE AND GENERAL (A&G) EXPENSE?

A. The MYRP Forecast revenue requirements include a $14.2 million increase in A&G expense. This increase is due to increases in Business Systems and Enterprise Security related to the Company's additional investments in the customer experience, software licensing and maintenance cost increases, Company labor costs, and increases in insurance costs. Additional information regarding Business Systems O&M is discussed by Mr. Reimer. Additional information regarding insurance costs is provided by Company witness Mr. Robert L. Miller.

Q. PLEASE DESCRIBE HOW CHANGES IN SALES RELATE TO THE RATE INCREASE.

A. As discussed by Company witness Ms. Jannell E. Marks, actual sales have declined from 2016 levels and are expected to continue to decline over the MYRP. Ms. Marks explains that the projected decrease is a result of declining Residential and Commercial and Industrial sales. Although Residential sales are expected to be strong in 2020 due to the COVID-19 pandemic, those increases are not enough to offset reductions in larger Commercial and Industrial sector sales and we expect Residential sales to decline in 2021 and to continue the pre-pandemic declining trend thereafter. Consequently, the Company's retail revenues are also expected to decrease, increasing the 2021 revenue deficiency.

Q. ARE THERE ANY OTHER MARGIN ITEMS WITH A SIGNIFICANT IMPACT ON THE 2021 REVENUE DEFICIENCY?

A. Not at this time. However, it is worth noting that while the Tax Cut and Jobs Act (TCJA) was implemented midway through the 2016-2019 MYRP, TCJA impacts are currently being refunded to customers in base rates, as approved in the Commission's Order in Docket No. E,G999/CI-17-895, and are included in the baseline numbers for the cost of service. As such, they will not appear as a driver of the 2021 revenue deficiency.

Q. ARE THE FUNCTIONAL CLASS CATEGORIES OF OPERATING EXPENSE COMPARABLE BETWEEN THE 2021 TEST YEAR AND THE DOCKET NO. E002/GR-15-826 2019 PLAN YEAR?

A. Yes. Budget amounts for both periods conform to the Federal Energy Regulatory Commission (FERC) Uniform System of Accounts. To better show cost drivers, especially as they relate to operating margins, some reclassifications are made in the cost driver analysis from the Jurisdictional COSS.

Q. DID YOU INCLUDE COMPARISONS OF THE CHANGE IN THE FUEL AND PURCHASED ENERGY EXPENSE AS PART OF THE O&M EXPENSE ANALYSIS?

A. No. Although the cost of fuel and purchased energy are considered to be an operating expense, recovery occurs through the Company's separate fuel clause adjustment (FCA) mechanism and true-up process. I provide a reconciliation of fuel costs and revenues in Exhibit___(BCH-1), Schedule 21, Fuel Reconciliation.

III. SUPPORTING INFORMATION

Q. WHAT TOPICS DO YOU DISCUSS IN THIS SECTION OF YOUR TESTIMONY?

A. In this section, I provide information related to data provided in our application, the selection of the test year and, the jurisdictional cost of service study.

A. Data Provided and Selection of the Test Year

Q. WHAT TOPICS DO YOU DISCUSS IN THIS SECTION OF YOUR TESTIMONY?

A. In this section, I will:

- identify the supporting financial information and related fiscal periods that we are providing in connection with the MYRP Forecast; and
- demonstrate that the supporting financial information and related fiscal periods that we are presenting provide appropriate information and facilitate review of our MYRP Forecast.

1) Overview

Q. PLEASE DEFINE THE FISCAL PERIODS FOR WHICH FINANCIAL DATA IS PROVIDED IN THIS PROCEEDING.

A. Following the Commission's rules, financial data is provided for 2019 (the most recent fiscal year), 2020 (the projected fiscal year), and 2021 (the test year). In addition, we provide financial data to support the MYRP Forecast. The most recent fiscal year (calendar year 2019) reflects the Company's actual financial results. For the projected fiscal year 2020, actual financial results through June 2020 are provided as rate base data, operating expenses, and revenues. Forecast projections are provided for the remainder of 2020. The MYRP Forecast reflects the Company's most recent available budget data.

All fiscal periods provided in this testimony are adjusted for traditional regulatory adjustments (e.g., charitable donations, etc.).

I also provide schedules showing: the actual unadjusted average rate base consisting of the same rate base components; unadjusted operating income; overall rate of return; the calculation of required income; and the income deficiency and revenue requirements for the most recent fiscal year (2019); the projected fiscal year (2020); and the MYRP Forecast. Separate rate base and income statement bridge schedules for the MYRP Forecast that identify test period adjustments are provided with my testimony.

2) MYRP Forecast

Q. WHAT WAS THE BASE SOURCE FOR THE PROPOSED MYRP FORECAST COSTS?

A. Calendar year 2021 was selected as the test year for this filing using Xcel Energy's most recent available budget data for the first year of the budget cycle. Use of a fully projected calendar test year (2021) is consistent with longstanding practice and precedent in the Company's rate cases before the Commission.

The 2022 and 2023 plan years reflect years two and three from the most recent available budget information, of which the 2021 test year is year one. Unlike our 2016-2019 MYRP, our plan year O&M is based on the budget for those years as opposed to using escalations from the test year budget. Using the same budget vintage for the test year and plan years allows for a consistent MYRP Forecast.

The 2021-2023 Budget is supported in Ms. Ostrom's Direct Testimony and provided in Volumes 5 (Budget Summary and Documentation) and 6 (Budget Documentation) of the Application.

Q. DOES THE COMPANY ANTICIPATE UPDATING SOME OF ITS INFORMATION IN REBUTTAL TESTIMONY?

A. Yes. Consistent with prior cases, we will update certain costs to incorporate updated information. More specifically, as in our 2016-2019 MYRP, we will review the following and update in this case as appropriate:

- Cost of capital to reflect the most currently available data;

- Current customer count and sales information and expected trends that might indicate that adjustments to the sales and customer counts forecast are needed;
- Assumptions used for calculating Qualified Pension, FAS 106 retiree medical, and FAS 112 post-employment benefits expense based on information as of December 31, 2020;
- O&M active health care may be updated to reflect actual 2020 active medical and pharmacy claims; and
- Property tax forecasts based upon property tax data that will become available during 2021.

Q. IN ADDITION TO THE UPDATES LISTED ABOVE THAT WILL REFLECT THE MOST CURRENT AVAILABLE DATA IN THE TEST YEAR, DO YOU ANTICIPATE ANY OTHER ADJUSTMENTS IN REBUTTAL TESTIMONY?

A. Yes. As discussed in further detail in Section VII, Annual Adjustments to the MYRP, Part F. Rebuttal Adjustments, of my testimony, we have identified certain adjustments that may be necessary. We have made these known adjustments for purposes of interim rates, and we will make adjustments for final rates in our Rebuttal Testimony.

3) Supporting Information and the 2021 Projected Test Year

Q. WHY DOES THE COMPANY USE 2019 AS ITS MOST RECENT FISCAL YEAR INSTEAD OF 2020?

A. Minn. R. 7825.3100, Subp. 10 provides the following definition:

> "Most recent fiscal year" is the *utility's prior fiscal year [here, 2019]* <u>*unless*</u> notice of a change in rates is filed with the commission within the last

> three months of the current fiscal year *and at least nine months of historical data is available for presentation of current fiscal year financial information*, in which case the most recent fiscal year is deemed to be the current fiscal year. (Emphasis added.)

In this proceeding, the Company's prior fiscal year is 2019, and its current fiscal year is 2020 because the two exceptions to the rule that would instead convert 2020 into the most recent fiscal year are not fulfilled. While the Company is filing this rate case within the last three months of 2020, nine months of actual 2020 data is not "available for presentation." Since that requirement cannot be met, the plain language of the Rule directs the Company to use 2019 as the most recent fiscal year, consistent with the Company's long-standing approach.

Nothing in the Rule requires the Company to delay its filing until additional 2020 data becomes available or to accelerate the availability of the actual data to include nine months of actual data with the filing. Rather, Minn. R. 7825.3100, Subp. 10 requires the Company to treat 2019 as the prior fiscal year and Minn. R. 7825.3100, Subp. 12 requires that we treat 2020 as the projected fiscal year.

Q. IS THIS APPROACH ALSO CONSISTENT WITH THE COMPANY'S PAST PRACTICES THAT HAVE BEEN ACCEPTED BY THE COMMISSION?

A. Yes. In our rate case in Docket E002/GR-12-961, the Administrative Law Judge (ALJ) found that the Company's practice was consistent with its filings in past rate cases and was in compliance with Commission rules. Therefore, the ALJ supported,[4] and the Commission adopted, the Company's use of a fully projected test year. Most recently, we utilized actual 2014 data as the "most

[4] ALJ Report Findings 866-873 in Docket No. E002/GR-12-961 (July 3, 2013).

recent fiscal year" data in Docket No. E002/GR-15-826, as 2015 actual data was not available for presentation at the time of that filing. There was no issue with that approach in that case.[5]

Q. DOES THE COMPANY'S PRACTICE RESULT IN LESS INFORMATION BEING INCLUDED IN THE FILING?

A. No. The Company filed information for 2019 (the most recent fiscal year), 2020 (the projected year), the unadjusted 2021 year, the adjusted 2021 test year, and the 2022-2023 plan years. Definitions and financial schedules related to 2019 actual and 2020 projections are included in the following locations.

- Volume 3, Required Information, Section II:
  - Tab 2, Jurisdictional Financial Summary Schedules, Schedule A-1
  - Tab 3, Rate Base Schedules, Section A, Schedule A-1
  - Tab 3, Rate Base Schedules, Section B, Schedule B-2
  - Tab 3, Rate Base Schedules, Section E, Schedule E, Page 2
  - Tab 4, Operating Income Schedules, Section A, Schedule A-1
  - Tab 4, Operating Income Schedules, Section B, Schedule B-1

[5] We recently noted that in one case, the Commission issued a rule variance in order to permit a utility to utilize the last full calendar year (2016 data) as the "most recent fiscal year" for a rate case filed in the last two months of 2017. *In the Matter of the Application of Minnesota Energy Resources Corporation for Authority to Increase Rates for Natural Gas Service in Minnesota,* ORDER ACCEPTING FILING, SUSPENDING RATES, EXTENDING TIMELINE, AND VARYING RULE, Docket No. G011/GR-15-736 (Dec. 5, 2017). We do not believe a variance is necessary here, just as it has not been necessary in prior NSPM rate cases, because utilizing 2019 data is consistent with the Minnesota Rule under the circumstances of this filing. But if the Commission determines that a variance is necessary, the Company requests a variance under Minn. R. 7829.3200, because (i) the Company began preparing this rate case filing several months before the requisite data was available for 2020, and it would be an excessive burden on the utility to wait to file the case or refile the case when 2020 data is available (and would not align with a calendar year test year); (ii) granting the variance would not adversely affect the public interest, because NSPM has used this approach in the past with the same extensive data, and it has resulted in just and reasonable rates; and (iii) granting the variance would not conflict with standards imposed by law.

- Tab 4, Operating Income Schedules, Section C, Schedules C-1 and C-3
- Tab 4, Operating Income Schedules, Section F, Schedule F, Page 2
- Tab 5, Rate of Return Cost of Capital Schedules, Sections A-D;

- Exhibit___(BCH-1), Schedule 7, Comparison of Detailed Rate Base Components;
- Exhibit___(BCH-1), Schedule 8, Comparison of Detailed Income Statement Components.

B. Jurisdictional Cost of Service Study

Q. WHAT TOPICS DO YOU DISCUSS IN THIS SECTION OF YOUR TESTIMONY?

A. In this section, I will explain the jurisdictional cost of service studies that we prepared for the MYRP Forecast.

Q. PLEASE DESCRIBE THE COMPONENTS OF THE JURISDICTIONAL COST OF SERVICE STUDY FOR THE MYRP Forecast.

A. A summary of the jurisdictional cost of service study for the MYRP Forecast is provided in Schedule 2, Summary of Revenue Requirements. The complete jurisdictional cost of service study for the MYRP Forecast provided in Schedule 3, Cost of Service Study Summary, and in Volume 4, Section II, Cost of Service Study (COSS) of this filing and include all the adjustments discussed in my Direct Testimony.

The jurisdictional cost of service study includes the following financial data input sections, for both Total Company and the Minnesota Jurisdiction: (i) capital structure; (ii) cost of capital; (iii) income tax rates; (iv) rate base; (v) income statement; (vi) income tax calculations; and (vii) cash working capital.

Q. PLEASE DESCRIBE THE JURISDICTIONAL COST OF SERVICE SUMMARY SCHEDULES.

A. The jurisdictional cost of service summary for each year of the MYRP Forecast is included as Schedule 3, Cost of Service Study Summary:

- The Rate Base Summary for Total Company electric operations and the Minnesota jurisdiction is shown on Page 1. It provides the assumed capital structure, including the earned overall rate of return on rate base and the earned ROE. The Rate Base Summary references a calculation of cash working capital, which is detailed in Exhibit ___(BCH-1), Schedule 4 (Cash Working Capital), and Volume 4, Section III, Rate Base (Plant), Tab P10, Cash Working Capital.
- An Income Statement for Total Company electric operations and the Minnesota jurisdiction is shown on Page 2 and Page 3. The income statement shows the determination of total operating income at present authorized retail rates. The Income Statement references calculations for federal and state income taxes, which are detailed on Page 3.
- The Revenue Requirement and Return Summary for Total Company electric operations and the Minnesota jurisdiction is shown on Page 4. It shows the revenue deficiency that needs to be recovered to enable the Minnesota jurisdiction electric operations to earn the requested rate of ROE and the total revenue requirements and the percent of increase that would result by increasing retail billing rates by the amount of the revenue deficiency.

Q. ARE THE REVENUE CONVERSION FACTOR CALCULATION AND THE MINNESOTA COMPOSITE INCOME TAX RATES INCLUDED IN THIS FILING?

A. Yes. The revenue conversion factor calculation is included in Volume 3, Section II.7, Required Financial Information, Other Supplemental Information, Tab B, Gross Revenue Conversion Factor; and composite income tax rates are included in Volume 3, Section II.4, Required Financial Information, Operating Income Schedules, Tab C, Income Tax Computation, Schedule C-5.

Q. PLEASE EXPLAIN HOW THE INTEREST DEDUCTION FOR DETERMINING TAXABLE INCOME IS CALCULATED.

A. The amount of interest deducted for income tax purposes is the weighted cost of debt capital multiplied by the average rate base. This is sometimes called "interest synchronization." The MYRP calculation for the interest synchronization is provided in Schedule 3, Cost of Service Summary, line 110.

Q. WHICH SCHEDULES IN YOUR EXHIBIT ARE RELATED TO RATE BASE?

A. I have provided three schedules related to rate base: Schedule 7, Comparison of Detailed Rate Base Components; Exhibit___(BCH-1) Schedules 10a-10c, 2021-2023 Rate Base Adjustment Schedules; and Exhibit___(BCH-1) Schedule 9, Rate Base, CWIP, and ADIT Summary. I discuss these schedules in Section IV; Rate Base and Section VII, Annual Adjustments to the MYRP. Additional comparative rate base schedules are provided in Volume 3, Required Information.

Q. WHICH SCHEDULES IN YOUR EXHIBIT ARE RELATED TO THE INCOME STATEMENT?

A. I have provided two schedules related to the income statement: Schedule 8, Comparison of Detailed Income Statement Components, and Exhibit___(BCH-1), Schedules 11a-11c, 2021-2023 Income Statement Adjustment Schedules. I discuss these schedules in Section V, Income Statement and Section VII, Annual Adjustments to the MYRP. Additional comparative income statement schedules are provided in Volume 3, Required Information.

IV. RATE BASE

Q. WHAT TOPICS DO YOU ADDRESS IN THIS SECTION OF YOUR TESTIMONY?

A. In this section of my testimony, I support the reasonableness of the Company's projected 2021-2023 MYRP rate base and identify and explain how the components of the rate base were determined, focusing on the 2021 test year and noting any limited situations where there are differences for the other years of the MYRP. I begin by providing the overall rate base calculation and identify its components, then walk through each of the MYRP Forecast components of rate base in turn.

Q. IS THE COMPANY'S PROJECTED 2021 TEST YEAR RATE BASE REASONABLE FOR PURPOSES OF DETERMINING FINAL RATES IN THIS PROCEEDING?

A. Yes. The projected 2021 test year rate base for the Company's Minnesota jurisdiction electric operations was developed using sound ratemaking principles and in a manner similar to prior Company electric rate cases. This is also true of the 2022-2023 plan years.

Q. PLEASE EXPLAIN WHAT RATE BASE REPRESENTS.

A. Rate base primarily reflects the capital expenditures made by a utility to secure plant, equipment, materials, supplies, and other assets necessary for the provision of utility service, reduced by amounts recovered from depreciation and non-investor sources of capital.

Q. PLEASE IDENTIFY THE MAJOR COMPONENTS OF THE PROJECTED 2021-2023 MYRP RATE BASE.

A. The MYRP rate base is generally composed of the following major items, which I later describe in detail:

- Net Utility Plant;
- Construction Work in Progress (CWIP);
- Accumulated Deferred Income Taxes (ADIT);
- Pre-Funded Allowance for Funds Used During Construction (AFUDC); and
- Other Rate Base.

Q. HOW DOES THE COMPANY CALCULATE RATE BASE?

A. The Company's rate base can be expressed using the breakdown on Page 27 of the "Electric Utility Cost Allocation Manual" of the National Association of Regulatory Utility Commissioners (NARUC) as follows:

	Original Average Cost of Electric Plant in Service (Plant)
Less:	Average Accumulated Depreciation Reserve (Reserve)
Less:	Average Accumulated Provision for Deferred Taxes (net of accts 281-283 and 190) (ADIT)
Plus:	Average Construction Work in Progress (CWIP)
Plus:	Average Working Capital (Work Cap)
Equals:	Rate Base

In this case, the calculation is as follows, using the average of the beginning of year (BOY) and end of year (EOY) balances for the test year:

Plant	$21,390,993	(per BCH-1, Schedule 3, Page 1, Line 23)
Reserve	(9,900,637)	(per BCH-1, Schedule 3, Page 1, Line 24)
ADIT	(2,245,198)	(per BCH-1, Schedule 3, Page 1, Line 32)
CWIP	394,160	(per BCH-1, Schedule 3, Page 1, Line 26)
Other Rate Base	311,259	(per BCH-1, Schedule 3, Page 1, Line 42)
Rate Base	$9,950,576	(thousands of dollars)

Q. PLEASE DESCRIBE THE SCHEDULES IN YOUR EXHIBIT THAT ARE RELATED TO THE TEST YEAR AVERAGE INVESTMENT IN RATE BASE.

A. Schedule 7, Comparison of Detailed Rate Base, provides a detailed statement of the rate base components. Page 1 provides a comparison of the rate base components for the 2021 test year to the 2019 plan year used in our 2016-2019 MYRP. Page 2 provides the rate base components for the MYRP Forecast.

Schedule 9, Rate Base, CWIP, and ADIT Summary, Page 1 of 4, shows a detailed average rate base by component for the 2021 test year for the Minnesota jurisdiction and Total Company, before and after making proposed test period adjustments. Page 2 shows the 2022 and 2023 plan years detailed average rate base by component for the Minnesota jurisdiction and Total Company. Page 3 shows the MYRP Forecast average Construction Work in Progress for the Minnesota jurisdiction and Total Company, before and after making proposed test period adjustments. Page 4 shows the MYRP Forecast for accumulated deferred income taxes for the Minnesota jurisdiction and Total Company, before and after making proposed test period adjustments.

Schedules 10a-10c, 2021-2023 Test/Plan Year Rate Base Adjustment Schedules, are a bridge schedule showing the 2021-2023 unadjusted rate base, each proposed rate base adjustment, and the resulting proposed 2021-2023 test/plan year rate base.

A. Net Utility Plant

Q. WHAT DOES NET UTILITY PLANT REPRESENT?

A. Net utility plant represents the Company's investment in plant and equipment that is used and useful in providing retail electric service to its customers, net of accumulated depreciation and amortization.

Q. PLEASE EXPLAIN THE METHOD USED TO CALCULATE NET UTILITY PLANT INVESTMENT IN THIS CASE.

A. The net utility plant is included in rate base at depreciated original cost reflecting the simple average of projected net plant balances at the beginning and end of the 2021 test year. Such treatment is consistent with the method employed in the Company's most recent Minnesota electric rate case.

Q. WHAT HISTORICAL BASE DID THE COMPANY USE AS A STARTING POINT TO DEVELOP THE PROJECTED NET PLANT BALANCES FOR THE BEGINNING OF THE 2021 TEST YEAR?

A. The historical base used for the beginning of the 2021 test year was the Company's actual net investment (Plant in Service less Accumulated Depreciation) on the Company's books and records as of June 30, 2020 plus the forecast for the remaining months of 2020. Similarly, the 2022 and 2023 projected beginning net plant balances are based on the forecasted balances at the end of 2021 and 2022, respectively, as walked forward from the actual net investment as of June 30, 2020.

Q. ON WHAT BASIS WERE NET PLANT BALANCES PROJECTED FOR THE END OF THE 2021 TEST YEAR?

A. The 2021 test year ending net plant balances were determined by applying the data contained in the 2021 capital budget to the above-described beginning test year balances, adjusted for retirements, depreciation, salvage and removal costs projected to occur during the 2021 test year. The same methodology was utilized to establish 2022 and 2023 end-of-year projected net plant balances.

Q. WHAT WAS THE AVERAGE NET UTILITY PLANT INCLUDED IN THE 2021 TEST YEAR RATE BASE?

A. The average net utility plant included in the 2021 test year rate base is $11.490 billion, as shown on Schedule 7, Comparison of Detailed Rate Base Components. This is comprised of an average plant balance of $21.391 billion as detailed on Schedule 7, minus an average depreciation reserve of $9.901 billion, also shown by component on Schedule 7.

B. Construction Work In Progress (CWIP)

Q. WHAT IS CONSTRUCTION WORK IN PROGRESS?

A. In Minnesota, CWIP is included as part of the revenue requirement calculation for base rates. CWIP is the accumulation of construction costs that directly relate to putting a fixed asset into use.

Q. HAS CWIP BEEN INCLUDED IN THE 2021 TEST YEAR AND 2022-2023 PLAN YEARS RATE BASE?

A. Yes. CWIP is included in rate base with a corresponding offset of AFUDC added to operating income, except where the Company is allowed to earn a current return. The rate base amount reflects a simple average of projected CWIP beginning and ending balances. This is consistent with the method employed in Minnesota and approved by the Commission in the Company's 2016-2019 MYRP and matches the use of an average rate base. The CWIP and AFUDC determinations for rate base are discussed in the Direct Testimony of Company witness Mr. Mark P. Moeller.

Q. HOW WERE THE 2021 TEST YEAR BEGINNING AND ENDING CWIP BALANCES DETERMINED?

A. The beginning balance for CWIP was the June 30, 2020 historical balance. The beginning CWIP balance was adjusted to reflect projected construction expenditures, AFUDC, and transfers to Plant in Service during the remainder of 2020 and in 2021 to obtain the beginning and ending 2021 test year CWIP balance. These projections were developed from the Company's 2021 capital budget.

C. Accumulated Deferred Income Taxes (ADIT)

Q. PLEASE DESCRIBE ACCUMULATED DEFERRED INCOME TAXES.

A. Inter-period differences exist between the book and taxable income treatment of certain accounting transactions. These differences typically originate in one period and reverse in one or more subsequent periods. For utilities, the largest such timing difference typically is the extent to which accelerated income tax depreciation exceeds book depreciation during the early years of an asset's service life. ADIT represents the cumulative net deferred tax amounts that have been allowed and recovered in rates in previous periods.

Q. WHY IS ADIT DEDUCTED IN ARRIVING AT TOTAL RATE BASE?

A. To the extent income taxes recovered in rates are deferred for later payment, they represent a prepayment by customers, a non-investor source of funds. The average projected ADIT balance is deducted in arriving at total rate base to recognize such funds are available for corporate use between the time they are collected in rates and ultimately remitted to the respective taxing authorities.

Q. WHAT AMOUNT OF ADIT WAS DEDUCTED TO ARRIVE AT THE 2021-2023 MYRP TEST YEAR RATE BASE?

A. As shown on Schedule 7, Comparison of Detailed Rate Base Components, $2.245 billion was deducted for the 2021 test year. This amount reflects a simple average of the projected beginning and ending 2021 test year ADIT balances and incorporates Internal Revenue Service (IRS) tax regulations. Specifically, Sec. 1.167(l) of the tax code defines a pro-rated schedule for the extent average accumulated deferred income taxes 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. Details related to the full MYRP Forecast ADIT are provided in Schedule 9, Rate Base, CWIP and ADIT Summary, on Page 4 of 4, and are discussed in more detail by Mr. Moeller.

Q. HAS THE COMPANY INCORPORATED THE EFFECTS OF THE TCJA INTO THE PROPOSED MYRP ADIT IN RATE BASE?

A. Yes. The Commission's Order in Docket No. E,G999/CI-17-895 directed the Company's amortizations of excess ADIT, which are included in the amounts shown on Schedule 7, Comparison of Detailed Rate Base Components, Pages 1 and 2. Additional information regarding the TCJA's effect on the deferred taxes associated with plant assets is addressed by Mr. Moeller. Support for the excess ADIT can be found in Volume 4, Section III Rate Base (Plant), Tab P2-3.

D. Pre-Funded AFUDC

Q. WHAT IS PRE-FUNDED AFUDC?

A. In Minnesota, AFUDC is included as part of the revenue requirement calculation for base rates. Specifically, during construction, AFUDC is calculated and included in the CWIP balance and is also included in operating income as an offset to the revenue requirement. AFUDC is added to the cost of related capital projects and is reflected in rate base when the related capital project is placed into service. Once a project is placed in-service, the recording of AFUDC ceases, and the total capital cost of the project including accumulated AFUDC is recovered through depreciation.

However, certain rate riders in Minnesota (*e.g.*, the TCR Rider and the Renewable Energy Standards (RES) Rider) include a current return on CWIP as part of the revenue requirement calculation for the rider. The capital projects associated with those riders do not include the accumulated AFUDC as part of rate base. Pre-funded AFUDC is needed to offset the accumulated AFUDC to align with the current return on CWIP in a rider.

Q. HOW IS PRE-FUNDED AFUDC TREATED?

A. Pre-funded AFUDC is calculated and credited against the total jurisdictional AFUDC to prevent double counting. This treatment, in effect, reduces the income offset provided by AFUDC and reduces the accumulated AFUDC that is added to rate base when a project is placed into service. The Company tracks Pre-funded AFUDC and the non-rider AFUDC separately so that the Minnesota jurisdictional customers are assured of receiving the entire benefit in lower fixed asset costs during the in-service period for the assets included in rate riders. In this way, we ensure that costs are recovered in the appropriate jurisdictions, pursuant to their specific ratemaking procedures.

Q. HOW DOES THE COMPANY ACCOUNT FOR PRE-FUNDED AFUDC?

A. Pre-funded AFUDC is recorded in FERC Account No. 253, Other Deferred Credits, during the construction process as AFUDC is incurred, separated by rate jurisdiction within this FERC account. Pre-funded AFUDC is related to projects recovering a current return on CWIP from customers in Minnesota and wholesale transmission customers who pay our FERC-regulated MISO Attachment O and Schedule 26 rates. Once the associated asset is placed into service, the Pre-Funded AFUDC balance is amortized over the same time period as the associated asset.

Q. HOW HAVE YOU TREATED PRE-FUNDED AFUDC IN THE 2021-2023 MYRP?

A. All Minnesota jurisdictional Pre-funded AFUDC has been directly assigned to the Minnesota jurisdiction, according to the functional class of the associated asset for CWIP, Depreciation Reserve, Plant in Service, and ADIT in rate base, and to depreciation and deferred taxes, and AFUDC on the income statement. Accumulated Pre-funded AFUDC is a reduction to rate base, with the amortization of the Pre-funded AFUDC balance being a reduction to depreciation expense. The deferred taxes associated with Pre-funded AFUDC create a deferred tax asset during construction that flows back as the book amortization is recognized. These Pre-funded AFUDC items are at a jurisdictional level; thus, the offset is made once the rate base and the income statement are jurisdictionalized. The Pre-funded AFUDC recorded and budgeted associated with our MISO transmission tariff have been allocated to Minnesota, North Dakota, and South Dakota jurisdictions based on 12 coincident peak demand. This allocation method is consistent with treatment of the underlying transmission assets and their associated expenses and revenues.

E. Other Rate Base

Q. PLEASE SUMMARIZE THE ITEMS YOU HAVE INCLUDED IN OTHER RATE BASE.

A. Other Rate Base is composed primarily of Working Capital. It also includes certain unamortized balances that are the result of specific ratemaking amortizations, as discussed below in my testimony.

Q. PLEASE EXPLAIN WHAT WORKING CAPITAL REPRESENTS.

A. Working Capital is the average investment in excess of net utility plant provided by investors that is required to provide day-to-day utility service. It includes items such as materials and supplies, fuel inventory, prepayments, and various non-plant assets and liabilities. The net cash requirement (referred to as Cash Working Capital) is shown separately.

Q. HOW WERE 2021-2023 MYRP MATERIALS AND SUPPLIES AND FUEL INVENTORY REQUIREMENTS CALCULATED?

A. The Materials and Supplies average balance included in the MYRP rate base are included on Schedule 3, Cost of Service Study Summary Page 1, Line 35, for each year of the MYRP Forecast. The MYRP average rate base amount for Fuel Inventory is included on Schedule 3, Cost of Service Study Summary Page 1, Line 36, for each year of the MYRP Forecast. The Materials and Supplies and Fuel Inventory amounts shown on Schedule 3 Page 1, Cost of Service Study Summary, are based on the 13-month average balances ending June 30, 2020, the most recent data available.

Q. HOW WERE 2021-2023 MYRP NON-PLANT ASSETS AND LIABILITIES DETERMINED?

A. These balances, as shown on Schedule 3 Page 1, Cost of Service Study Summary, represent 2021-2023 estimates of these balances. Any book/tax timing differences associated with these items have been reflected in the determination of current and deferred income tax provision and ADIT balances previously discussed. The Non-Plant Assets and Liabilities average balance are included on Schedule 3, Cost of Service Study Summary Page 1, Line 37, for each year of the MYRP Forecast.

Q. HOW WERE 2021-2023 MYRP PREPAYMENTS AND OTHER WORKING CAPITAL ITEMS DETERMINED?

A. Prepayments and Other Working Capital, such as customer advances and deposits, are based on the actual 13-month average balances during the period ended June 30, 2020, as a proxy for the 2021-2023 MYRP. Our nuclear outage amortization is also included in Other Working Capital. The average rate base for nuclear outage amortization is based on the average of the beginning of year and end of year balances. The unamortized balances included in this section are based on the amortization schedules as described in Section IV. The Prepayments and Other Working Capital average balances are included on Schedule 3, Cost of Service Study Summary Page 1, Lines 38-40, for each year of the MYRP Forecast.

Q. HOW WERE THE MYRP FORECAST CASH WORKING CAPITAL REQUIREMENTS DETERMINED?

A. Cash Working Capital requirements have been determined by applying the results of a comprehensive lead/lag study to the projected MYRP Forecast revenues and expenses.

Q. WERE THE COMPONENTS OF THE MYRP Forecast CASH WORKING CAPITAL CALCULATED CONSISTENT WITH METHODS USED IN THE 2016-2019 MYRP?

A. Yes. The current MYRP Forecast cash working capital has been calculated consistent with methods accepted in our most recent completed Minnesota electric rate case.

Q. PLEASE BRIEFLY EXPLAIN HOW A LEAD/LAG STUDY MEASURES CASH WORKING CAPITAL.

A. A lead/lag study is a detailed analysis of the time periods involved in the utility's receipt and disbursement of funds. The study measures the difference in days between the date services to a customer are rendered and the revenues for that service are received, and the date the costs of rendering the services are incurred until the related disbursements are actually made.

Q. HAS XCEL ENERGY'S LEAD/LAG STUDY BEEN UPDATED SINCE THE 2016-2019 MYRP RATE CASE?

A. Yes. The Company has updated the lead/lag study for the calculation of the lead and lag days for all categories through year-end 2019, using the methodology for calculating the lead/lag days consistent with the Company's prior electric and gas regulatory filings. The results of the updated lead/lag study for electric operations were incorporated into the Minnesota jurisdiction cash working capital calculations as shown on Schedule 3, Cost of Service Study Summary, Page 1.

Q. WHAT ARE THE CURRENT MYRP FORECAST CASH WORKING CAPITAL AMOUNTS?

A. The amounts included as reduction in average rate base in the MYRP Forecast are based on the results of our lead/lag study prepared consistently with previous rate cases. The resulting Cash Working Capital amounts are as follows:

- 2021 Test Year: ($143.3 million);
- 2022 Plan Year: ($153.7 million);
- 2023 Plan Year: ($164.5 million).

Q. HAS THERE BEEN A CHANGE IN THE TEST-YEAR CASH WORKING CAPITAL AMOUNT SINCE THE 2016-2019 MYRP?

A. Yes. The $143.3 million reduction in test year Cash Working Capital requirement is a $32.2 million greater reduction than the amount of the reduction in the test year in the 2016-2019 MYRP ($111.1 million).

Q. WHAT IS THE SOURCE OF THE CHANGE IN CASH WORKING CAPITAL?

A. The change in Cash Working Capital results in a corresponding decrease in average rate base. This change is primarily due to the net changes in the average expense lead and revenue lag days between the two periods. Average revenue lag days decreased to 38.00 in 2021 from 41.58 in 2016, meaning the Company's revenues are being collected on average 3.58 days faster in 2021 than in 2016. Conversely, the Company's average expense lead days increased to 56.69 in 2021 from 56.34 in 2016, meaning that the Company's cash outlay for paying expenses has been extended by an average of 0.35 days. The shorter time in collection of revenues greatly exceeded the slower disbursing of cash and has decreased the cash working capital balance to be included in rate base.

Q. WHAT IS THE SIGNIFICANCE OF NEGATIVE CASH WORKING CAPITAL?

A. A negative cash working capital balance indicates that overall revenue collections occur sooner than the date when the associated costs of service are paid. In other words, on average, more cash requirements are being provided by customers and vendors. The negative cash working capital reduces rate base to compensate customers for funds provided to meet cash working capital requirements. It should be noted that changes in the revenues or expenses could cause the cash working capital calculation to change. The Company will update the 2021-2023 MYRP COSS accordingly through this proceeding.

V. INCOME STATEMENT

Q. WHAT TOPICS WILL YOU DISCUSS IN THIS SECTION OF YOUR TESTIMONY?

A. In this section, I will support the reasonableness of the Company's proposed MYRP income statements. I begin by providing the overall income statement calculations and identify their components, then walk through each of the MYRP components of the income statements in turn.

Q. ARE THE COMPANY'S PROPOSED MYRP INCOME STATEMENTS REASONABLE FOR DETERMINING FINAL RATES IN THIS PROCEEDING?

A. Yes. The proposed MYRP income statements for the Company's Minnesota jurisdiction electric operations were developed using sound ratemaking principles in a manner similar to prior Company electric rate cases.

Q. PLEASE IDENTIFY THE MAJOR COMPONENTS OF THE PROJECTED INCOME STATEMENTS.

A. The following are the major components of the MYRP income statements:

- Revenues;
- Operating and Maintenance Expenses;
- Depreciation Expense;
- Taxes;
- AFUDC; and
- Interchange Agreement.

Q. PLEASE DESCRIBE THE SCHEDULES TO YOUR TESTIMONY THAT ARE RELATED TO THE INCOME STATEMENT.

A. Schedules 11a-11c, 2021-2023 Income Statement Adjustment Schedules, are bridge schedules that show the unadjusted income statement, each proposed income statement adjustment, and the resulting proposed income statement for each year of the MYRP Forecast. Schedules 11a-11c also include the revenue deficiency amount for each item included in this schedule.

Schedule 8, Comparison of Detailed Income Statement Components, provides a detailed statement of the income statement components. Page 1 provides a comparison of income statement components for the 2021 test year to the 2019 plan year used in our most recent rate case. Page 2 provides the income statement components for the MYRP Forecast.

A. Revenues

Q. HOW DOES THE COMPANY PRESENT ITS PROJECTED SALES FOR THE MYRP FORECAST?

A. The MYRP sales volumes are supported by Ms. Marks. Ms. Marks discusses the bases for the Company's sales forecasts, including the use of normal weather to develop the Company's projected MYRP sales.

Q. DO RETAIL OPERATING REVENUES REFLECT THE PROJECTED LEVEL OF UNBILLED SALES VOLUMES IN THE MYRP FORECAST?

A. Yes. As Ms. Marks explains, the projected level of unbilled sales is incorporated into the retail sales forecast on a calendar-month basis. This eliminates the need to reconcile billing-month sales to calendar-month sales by recording unbilled revenues.

Q. HAVE YOU CONSIDERED OTHER OPERATING REVENUES AS AN OFFSET TO THE RETAIL REVENUE REQUIREMENT?

A. Yes. The MYRP Forecast includes items such as revenues from sales to other utilities, certain revenues from wholesale trading activities, wholesale transmission revenues, and specific tariff charges, including service activation fees, reconnection fees, and others. In areas where the Company did not budget for the collection of these tariffed charges, a representative level was determined and included as part of the revenues in the cost of service study. Other operating revenues also include billings to NSPW under the Interchange Agreement.

Consistent with our previous rate cases, I have included an adjustment to use the three-year average (2018, 2019, and 2020 Bridge) for certain other revenues in the determination of the MYRP Forecast levels of Other Revenues. This adjustment accounts for variability and includes other unbudgeted revenue that the Company receives in an actual year that cannot be anticipated for budget purposes. I discuss this revenue adjustment and other adjustments to revenues in more detail in Section VII, Annual Adjustments to the MYRP.

Q. HAVE REVENUES AND EXPENSES ASSOCIATED WITH NSPM'S NON-REGULATED BUSINESS ACTIVITIES BEEN EXCLUDED FROM THE MYRP COST OF SERVICE?

A. Yes. We have excluded the revenues and expenses associated with Commission-approved non-regulated business activities (i.e. customer-owned street lighting maintenance and Sherco steam sales to Liberty Paper) from the MYRP cost of service. Because these activities are recorded in below-the-line accounts, they were not included in the MYRP Forecast.

Q. HOW ARE REVENUES AND EXPENSES RELATED TO THE MISO SCHEDULES TREATED IN RATES?

A. Both revenues and expenses related to the MISO schedules are included in the determination of retail rates through either base rates, the FCA, or the TCR Rider. Base rate recovery, for example, includes both the revenues received from MISO and the expense billings from MISO for Schedules 1 (Scheduling, System Control, and Dispatch Service) and 2 (Reactive Supply and Voltage). The FCA, for example, includes Schedule 3 (Regulating Reserve). The TCR Rider includes recovery of Schedule 26 (Network Upgrade from Transmission Expansion Plan) and 26-A (Multi-Value Project Usage Rate) revenues and expenses. The TCR Rider also includes, for capital projects not regionally shared, an Open Access Transmission Tariff (OATT) Revenue Credit to estimate the revenue that will be collected for the project from wholesale transmission customers. The treatment of revenues and expenses related to the MISO schedules is consistent with their treatment in prior rate cases.

Q. WHAT ARE WHOLESALE MARGINS?

A. There are two categories of transactions that generate wholesale margins (revenues less costs): asset based transactions; and non-asset based transactions. Asset based transactions are comprised of short-term sales of excess energy or capacity from Company-owned generation assets or power purchase agreements (PPAs) executed to serve our native load customers. The Company executes these asset based transactions through bilateral agreements with specific wholesale customers and through sales directly into the MISO energy market. Sales into the MISO market account for the bulk of these transactions.

Non-asset based transactions are wholesale trading transactions undertaken to obtain margins from purchases and sales of energy or capacity unrelated to meeting the energy needs of our native load customers. The only transactions that qualify as non-asset based transactions are third-party supplied electricity or financial transactions that are not purchased to meet the needs of our retail customers and that are then resold to other utilities or market participants.

Q HOW HAVE ASSET BASED MARGINS BEEN TREATED IN PRIOR RATE CASES?

A. Because asset based margins are created by selling energy or capacity from generating facilities or PPAs paid for by customers, all asset based margins have been credited to customers. In each of our last three rate cases, the Commission approved passing the sales margins through to customers using the FCA.

Q. IS THE COMPANY RECOMMENDING ANY CHANGE TO THE TREATMENT OF ASSET BASED MARGINS?

A. No. The Company recommends the same treatment of crediting asset based energy sales margins to customers through the FCA going forward, which is reflected in an adjustment discussed in Section VII, Annual Adjustments to the MYRP.

Q. HOW HAVE NON-ASSET BASED MARGINS BEEN ADDRESSED IN PRIOR CASES?

A. In our last two rate cases: (i) 100 percent of the non-asset based trading margins were retained by the Company; and (ii) 100 percent of the fully allocated O&M costs and IT system-related costs associated with non-asset based trading margins were excluded from the test year and, thus, resulted in a decrease in test year operating expenses.

Q. HAS THE COMPANY CONDUCTED INCREMENTAL AND FULLY ALLOCATED COST STUDIES OF NON-ASSET BASED TRADING?

A. No. At one time, the Company advocated a contribution from non-asset based margins based on incremental cost. As a consequence, the Commission ordered the Company to prepare incremental and fully allocated cost studies to support the Company's position. However, the Company is already required to exclude the fully allocated non-asset based trading costs from test year expense, and because we requested the elimination of an incremental cost study in Docket

No. E002/GR-15-826 with no comment or objection, no incremental cost study was prepared for this proceeding.

Q. IS THE COMPANY RECOMMENDING ANY CHANGE TO THE TREATMENT OF NON-ASSET BASED MARGINS?

A. The only change in the treatment of non-asset based margins is the elimination of the incremental cost study. Consistent with past Commission decisions, we are making an adjustment to exclude costs equal to the fully allocated cost of non-asset based trading, as further explained in Exhibit___(BCH-1) Schedule 17 and Volume 4, Section VIII Adjustments, Tab A23, Trading: Non Asset-Based Admin.

Q. UNDER THE COMPANY'S PROPOSALS FOR ASSET BASED MARGINS AND NON-ASSET BASE MARGINS, IS IT NECESSARY TO MAKE ANY TEST OR PLAN YEAR ADJUSTMENTS?

A. Yes, we make three adjustments. First, with respect to asset-based energy sales margins, the 2021-2023 budget base data includes all fuel costs and trading revenues. However, all asset-based energy sales margins are passed through to the customers in the FCA. The fuel clause revenue included in retail revenue does not include asset-based margins. Therefore, the Asset Margin Sharing adjustment excludes asset-based energy sales revenues and expenses from the MYRP Forecast.

Second, the 2021-2023 budget base data does not reserve the non-asset based trading margin for the shareholders. Therefore, the Non-Asset Margin

Retention adjustment removes these revenues and expenses from the test and plan years.

Lastly, the Non-Asset Trading O&M Credit adjustment removes the operating expenses in the income statement for the fully allocated O&M and IT-related costs of non-asset based trading activity. The MYRP Forecast adjustments are also included in Section VII, Annual Adjustments to the MYRP.

B. Operating and Maintenance Expenses

Q. HOW DOES THE COMPANY CALCULATE OPERATING EXPENSES?

A. The Company's operating expenses can be expressed using the breakdown on Pages 30-31 of the "Electric Utility Cost Allocation Manual" of the National Association of Regulatory Utility Commissioners (NARUC) as follows:

Operation and Maintenance Expense (including fuel) (Operating Exp)
\+ Depreciation Expense (Depreciation)
\+ Miscellaneous Amortization Expense (Amortization)
\+ Taxes other than Income Taxes (Other Taxes)
\+ Income Taxes (Income Tax)
= Total Expenses

In this case, the calculation is provided in Table 6 below:

Table 6

Operating Expenses

	Item	2021 Test Year Amount ($000s)	2022 Plan Year Amount ($000s)	2023 Plan Year Amount ($000s)	Exhibit__ (BCH-1), Sch. 3 Reference
	Operating Expense	$ 2,352,958	$ 2,376,248	$ 2,399,661	Page 2, Line 74
plus	Depreciation	737,364	778,372	792,829	Page 2, Line 76
plus	Amortization	55,040	51,576	49,467	Page 2, Line 77
plus	Other Taxes	135,271	82,667	95,041	Page 2, Line 88
plus	Income Tax	(84,104)	(41,137)	(61,484)	Page 3, Line 134
equals	Total Expense	$ 3,196,529	$ 3,247,726	$ 3,275,514	Page 3, Line 138

Q. WHAT ARE THE PRINCIPLE O&M EXPENSE CATEGORIES?

A. The principle expense categories are:

- Fuel & Purchased Energy;
- Power Production;
- Regional Markets;
- Transmission Interchange;
- Transmission;
- Distribution;
- Customer Accounting;
- Customer Service & Information;
- Sales, Economic Development and Other; and
- Administrative and General.

Q. HOW ARE FUEL AND PURCHASED ENERGY COSTS TREATED?

A. The fuel and purchased energy costs are collected through the FCA. Those costs are fully offset by revenues from the FCA or the Interchange Agreement, as described later in my Direct Testimony. Therefore, these costs have no impact on the 2021-2023 MYRP revenue deficiency.

Q. HAS THIS CHANGED SINCE THE 2016-2019 MYRP?

A. Yes. While the level of fuel revenues and expenses are consistent with the 2016-2019 MYRP, the Company is no longer providing a base cost of energy filing with this rate case, consistent with the Commission's November 5, 2019, Order Approving Compliance Filings in Docket No. E999/CI-03-802. Consistent with the Commission's Order, we have provided financial schedules that reflect a cost of service with and without fuel revenues and expenses. Where comparisons are made with prior years, we continue to present those financial schedules with fuel revenues and expenses to allow comparison. Consistent with the Commission's November 5, 2019, Order in Docket No. E999/CI-03-802, and as discussed in greater detail later in my testimony, the rates proposed exclude Fuel Clause Adjustment-related costs.

Q. WHAT ARE POWER PRODUCTION COSTS AND HOW ARE THEY DETERMINED?

A. Power production costs are primarily the costs of operating our generating facilities. These costs are budgeted through development of a production budget prepared to serve the combined energy and demand requirements of the NSP System (used for both NSPM and NSPW). Please see the Direct Testimony of Ms. Randolph for further information related to how the Company budgets for the operation and maintenance of our generation fleet.

Q. HOW DOES XCEL ENERGY DEVELOP ITS TEST YEAR TRANSMISSION EXPENSE?

A. Transmission expenses are the O&M costs associated with operating and maintaining our system transmission facilities. These costs are budgeted through development of a transmission budget prepared to serve the NSP System (*i.e.*, for both NSPM and NSPW). These costs and their development are detailed in Mr. Benson's Direct Testimony.

Q. HOW DOES XCEL ENERGY DEVELOP ITS TEST YEAR DISTRIBUTION EXPENSE?

A. Distribution expenses are the O&M costs associated with operating and maintaining our Minnesota distribution facilities. These costs are developed through a distribution budget prepared for both the NSPM electric and gas utilities. These costs and their development are detailed in the Direct Testimony of Ms. Bloch. The allocation of these costs to the electric utility and then to the Minnesota jurisdiction is addressed in Section VI of my Direct Testimony.

Q. HOW DOES XCEL ENERGY DEVELOP ITS TEST YEAR CUSTOMER SERVICE EXPENSE?

A Customer Service O&M cost is associated with providing meter reading, billing, credit and collections, bad debt expense, contact center, and operational support services. These costs are developed through the Customer Care budget prepared for both the NSPM electric and gas utilities. These costs and their development are detailed in the Direct Testimony of Company witness Mr. Christopher C. Cardenas. The allocation of these costs to the electric utility and then to the Minnesota jurisdiction is addressed in Section VI of my Direct Testimony.

Q. WHAT COSTS ARE INCLUDED IN ADMINISTRATIVE AND GENERAL (A&G) EXPENSE?

A. A&G expense includes Information Technology (IT), compensation, office supplies and expenses, and consulting services for officers, executives, and other Company employees properly chargeable to utility operations and not chargeable directly to a particular operating function. Also included in A&G expense are insurance and other costs related to injury or damage claims made by employees or others, employee pensions and benefits, regulatory expenses, general advertising expense, utility rental expense not properly chargeable directly to a particular operating function, and maintenance costs assignable to the customer accounts, sales, and A&G functions.

Q. ARE ANY COSTS RELATED TO CIVIC OR POLITICAL ACTIVITIES (LOBBYING), IDENTIFIED IN THE COST OF SERVICE, OR ADJUSTMENTS?

A. No. The Company records all lobbying costs to below-the-line accounting, FERC account 426.4, Expenditures For Certain Civic, Political, and Related Activities. The Company prepares the unadjusted expenses for the test year using queries that restrict the data to only above-the-line accounts (FERC Accounts 500 through 935). Thus, no adjustment to the cost of service for lobbying costs is required, as these below-the-line amounts are not used in our development of the test year cost of service. We have also excluded the portion of organizational dues associated with lobbying activities. Company witness

Mr. William K. Husen addresses our efforts to identify and remove lobbying expenses in his Direct Testimony.[6]

C. Depreciation Expense

Q. WHAT IS THE BASIS OF THE DEPRECIATION RATES AND EXPENSE USED IN THE 2021-2023 MYRP?

A. Depreciation expense for the 2021 test year base data reflects the Company's depreciation rates last certified by the Commission plus adjustments for the pending 2020 Average Remaining Life filing (Docket No. E, G002/D-19-723) and the pending 2020 Annual Update of Remaining Lives and Depreciation Rates for Transmission, Distribution and General Accounts (Docket No. E,G002/D-20-635). These adjustments are discussed in Section VII (adjustments 3 and 4). Mr. Moeller discusses the Company's depreciation expense in his Direct Testimony.

D. Taxes

Q. WHAT TAX EXPENSES ARE INCLUDED IN THE 2021 TEST YEAR INCOME STATEMENT?

A. We have line items for Property; Income Taxes including Deferred Income Tax, Investment Tax Credits and Federal and State Income Tax; and Payroll. The State and Federal income taxes are calculated in Schedule 3, Cost of Service Study Summary for 2021 test year, Page 3 of 4.

[6] Charitable contributions, economic development contributions, and Chamber of Commerce dues are other below-the-line expenses that are moved above the line, in part, through adjustments described in Section VII.

Q. HOW ARE PROPERTY TAXES DETERMINED FOR THE JURISDICTION?

A. Property taxes are determined on a NSPM Total Company basis. The functions are then allocated to the Company's regulatory jurisdictions using the demand allocator for electric production and transmission, the gas design day allocator for gas production, and transmission and distribution is direct assigned by state for both electric and gas. Please see Volume 4, Section III Rate Base (Plant), Tab P6, Property Tax for more details.

Q. HOW ARE INCOME TAXES DETERMINED FOR THE JURISDICTION?

A. Income taxes are determined based on total before tax book income, tax additions, and deductions which determine deferred income taxes and the resulting taxable income that is used to calculate federal and state income taxes. The federal income tax rate reflects the 21 percent rate effective January 1, 2018 with the enactment of the TCJA. The utilization or generation of net operating losses or tax credits impact both deferred income taxes and federal and state income taxes, which I will discuss in more detail below.

Q. PLEASE SUMMARIZE THE RATEMAKING TREATMENT OF NET OPERATING LOSSES (NOLS).

A. The Company continues to follow the resolution of "Tax Normalization and Allowance for Net Operating Losses" from the last three rate cases, which was reflected in Exhibit 105 in Docket No. E002/GR-10-971. Specifically, the Company will continue to give back to retail customers annually the revenue requirement benefit associated with the utilization of tax deductions and credits carried forward from prior periods.

NOLs require an adjustment that offsets the part of the ADIT rate base reduction that is associated with the accelerated depreciation deductions that have exceeded the Company's taxable income and have, thus, not resulted in deferral of income taxes. That adjustment is needed to keep the Company's rate base consistent with the income tax deductions that the Company has been able to use. Keeping a balance of rate-base reductions resulting from the ADIT and the use of accelerated depreciation deductions is required under federal income tax law as part of "normalization" for both accounting and ratemaking.

The timing of utilization and the carry-forward balances associated with unused deductions and credits will continue to change over time as the Company's revenue and deduction levels change. The annual reporting process, which incorporates actual revenues, deductions, and cost of capital, will continue to be the vehicle to track the utilization and balances and annually refund any utilization that has not been applied in base rates. The Company is not proposing any changes to that reporting process in this case.

Had this rate treatment not been approved by the Commission, the 2021 test year revenue requirement would be the same. However, if utilization of carried-forward deductions and credits took place outside of a rate case test year, then customers would not receive refunds for the revenue requirement value. Therefore, this treatment ensures customers are protected in the event of changes in the utilization of tax deductions and credits.

Q. PLEASE EXPLAIN HOW THE COMPANY DETERMINES WHETHER DEFERRED TAX ASSETS (DTAS) ARE CREATED OR CONSUMED.

A. The calculation of income taxes determines whether DTAs are created or consumed. After the calculated income tax expense is reduced for allowed NOL deductions or tax credits, the remaining income tax credits and deductions are "carried forward" and can be used to reduce taxes in future years. The federal income tax code and tax regulations dealing with NOLs state that unused deductions carried forward to a future tax year must be utilized before credits. The opposite is true during a time of setup. To the extent the calculated income tax expense is negative, first tax credits, and then depreciation deductions, are reversed, carried forward, and are available for utilization in a future period. This reversal creates a reduction to deferred tax expense, resulting in the creation of a DTA.

In future periods, to the extent the calculated income tax expense is positive, the federal income tax code and tax regulations prioritize that first depreciation deductions that were carried forward, and then credits that were carried forward are utilized to reduce the income tax expense by 80 percent for depreciation deductions and 75 percent for credits. This utilization creates an increase in deferred tax expense, reducing the balance of the DTA. Once all depreciation deductions and credits previously carried forward are utilized, the Company will have returned to a positive tax position. This is normal NOL accounting.

For the purpose of determining the NOL, these income tax calculations are done on an all-inclusive jurisdictional cost of service basis in which rider revenues and rider related investments are included with non-rider revenues and investments. This approach determines the extent to which the NSPM Electric Utility Minnesota retail jurisdiction is in a tax loss position or in a position to utilize deductions and credits carried forward from previous periods as is the case with the 2021 test year. This approach ensures that any reduction in revenue requirements resulting from the utilization of deductions or credits carried forward from prior periods is returned to customers as soon as it is available in the form of a rate refund or reduction to base rates.

These balances related to unused credits and deductions are reported in the Company's May 1 Jurisdictional Annual Reports, including the (most recent) May 1, 2020 Jurisdictional Annual Report. Separate detailed reporting and the revenue requirement value associated with any utilization was most recently reported on June 1, 2020. By having these annual determinations made on an all-in basis, the jurisdictional cost of service study (JCOSS) includes actual data for both rider recovery and base rate recovery. Any change in rider recovery by the Commission will be incorporated in this process.

Q. DO THE DTAS AFFECT THE 2021-2023 MYRP REVENUE REQUIREMENTS?

A. Yes. The Company's 2021-2023 MYRP COSS includes a revenue requirement increase associated with Production Tax Credits (PTCs) carried forward from prior periods to the 2021 test year and 2021-2023 MYRP generation of federal tax credits to be carried forward based on the Company's 2021-2023 MYRP COSS. An accounting for the balances carried forward to the 2021 test year COSS, as well as the documented calculations supporting this revenue requirement increase, can be found in Exhibit___(BCH-1), Schedule 20, Net Operating Loss.

It should be noted that any change 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. The Company will update the 2021-2023 MYRP COSS accordingly.

Q. HOW WILL THE RATES SET IN THIS CASE AFFECT THE UTILIZATION OF DTAS IN FUTURE TEST YEARS?

A. The utilization of DTAs is based on taxable income for the NSPM retail electric jurisdiction. Taxable income is determined by total revenues less total deductions and total tax credits. Once base rates are set in this case for the 2021 test year and any additional years considered by the Commission in the Company's multi-year rate proposal, they will remain in place until changed in another electric rate case. If all other factors are held constant, an increase in base rate revenue as proposed by the Company in this case will increase the utilization of deferred tax assets in future years.

Q. WHAT ARE PTCS?

A. PTCs are per-kWh tax credits to income for electricity generated using qualified renewable energy resources.

Q. WHAT IS THE LEVEL OF PTCS INCLUDED IN THE STATE AND FEDERAL INCOME TAX CALCULATION IN THE 2021 TEST YEAR?

A. As shown on Exhibit___ (BCH-1), Schedule 18, Production Tax Credits, the MYRP Forecast assumes PTCs for the Company-owned wind farms as shown in Table 7 below.

Table 7

Production Tax Credits included in MYRP Forecast

(Amount in $000s)	2021	2022	2023
MN Jurisdictional PTC	$140,315	$140,311	$140,315
MN PTC Impact on Revenue Requirement	(196,911)	(196,906)	(196,911)
MN PTC Impact on Rev Req net of I/A	(162,951)	(162,947)	(162,951)

We expect production to begin at additional wind facilities in 2021. Due to the anticipated in-service date of these projects, the Company is recommending that these projects be recovered through the RES Rider. I provide a discussion later in this Section of my Direct Testimony about how PTCs interact with the deferred tax asset calculations in the 2021 test year.

Q. WHAT IS THE COMPANY'S PROPOSAL WITH RESPECT TO THE TREATMENT OF PTCS BETWEEN TEST YEARS?

A. In addition to the PTCs included in the RES Rider, the Company continues to recommend that the RES Rider act as a true-up mechanism for the PTCs related to projects already in service and included in base rates as a part of the 2021 test year cost of service. We propose that the difference in the dollar value of actual PTCs generated and the amounts included in the test year be recorded to the RES Tracker account and either returned to, or recovered from, customers through the RES Rider. This approach meets our understanding of the current regulatory treatment for PTCs.

Q. PLEASE EXPLAIN THE EFFECT OF TAX TREATMENT OF PTCS AND THE REQUIRED REVENUE LEVEL NECESSARY TO COVER THE CHANGE IN OPERATING INCOME.

A. PTCs create a direct reduction (credit) to income tax expense causing a corresponding increase to operating income. Every dollar change in operating income needs a revenue conversion factor to be applied to determine the pre-tax revenue level necessary to achieve the operating income change. The revenue conversion factor calculation is included in Volume 3, Section II.7, Required Financial Information, Other Supplemental Information, Tab B, Gross Revenue Conversion Factor; and composite income tax rates are included in Volume 3, Section II.4, Required Financial Information, Operating Income Schedules, Tab C, Schedule C-5.

Q. WHAT IS THE REDUCTION IN REVENUE REQUIREMENTS FOR PTCS REFLECTED IN THE 2021 TEST YEAR FINANCIAL STATEMENTS?

A. The State of Minnesota jurisdictional revenue requirement impact of PTCs in the test year, after applying the 1.40335 revenue conversion factor, is ($196.9 million) or ($163.0 million) net of Interchange Agreement billings to NSPW. Support for these calculations is shown on Schedule 18, Production Tax Credits.

E. AFUDC

Q. WHAT IS AFUDC, AND WHAT IS ITS FUNCTION IN THE INCOME STATEMENT?

A. As previously noted, AFUDC is the cost of financing during the period a capital investment is included in CWIP. Once an asset is placed in service, the total cost to construct including accumulated AFUDC is recovered through depreciation expense. Mr. Moeller's Direct Testimony discusses the role AFUDC plays in allowing utilities to recover their cost of financing. In the income statement, AFUDC is used to offset expenses, thus increasing total operating income, and reducing the revenue requirement. This provides a direct offset to the return requirement associated with the inclusion of CWIP in rate base. Please see Section IV. Rate Base, for a detailed discussion of the relationship between CWIP and AFUDC and a discussion of Pre-Funded AFUDC.

F. Interchange Agreement

Q. PLEASE DESCRIBE THE INTERCHANGE AGREEMENT BETWEEN THE COMPANY AND NSPW.

A. The Company and NSPW operate a single integrated electric generation and transmission system and a single electrical "local balancing authority area." This integrated NSP System jointly serves the electric customers and loads of the Company and NSPW. However, the specific generators and transmission facilities making up the NSP System are owned by the two separate legal entities (the Company and NSPW), with the ownership boundary at the Minnesota/Wisconsin border. The Interchange Agreement is a FERC-approved contractual mechanism that provides a means to share the costs of the integrated NSP System between the Company and NSPW.

Q. PLEASE DESCRIBE THE COSTS AND REVENUES ALLOCATED BETWEEN THE COMPANY AND NSPW UNDER THE INTERCHANGE AGREEMENT.

A. Under the Interchange Agreement, the Company and NSPW share annual system generation (production) and transmission costs. Under the Interchange Agreement formulas, approximately 16 percent of the costs of the Company system are allocated to NSPW, and approximately 84 percent of the NSPW system costs are allocated to the Company, because approximately 84 percent of the load on the integrated system is the Company load and 16 percent is NSPW load. The exact allocation percentages are determined by the allocation factors updated and filed at FERC annually.

The Interchange Agreement also provides for an allocation of revenues received by the Company and NSPW, such as revenues from transmission services or off-system wholesale sales. Interchange Agreement costs and revenues are budgeted by the Company and NSPW annually. Thus, the Company's budget shows Interchange Revenues, which are revenues that reflect the charges to NSPW for its share of production and transmission assets and associated expenses. Likewise, Interchange Expense reflects the Company's budgeted payments to NSPW for its proportionate share of the costs of generation and transmission assets and associated expenses incurred by NSPW to serve the NSP System needs.

The MYRP Forecast Interchange Revenue and Interchange Expenses have been calculated using 2021-2023 Company and NSPW budget information. This is consistent with the treatment of Interchange Revenues and Interchange Expenses in our last three rate cases.

Q. PLEASE DESCRIBE THE INTERCHANGE AGREEMENT OFF-SET TREATMENT BEING EMPLOYED IN THE MYRP FORECAST COSS.

A. As discussed earlier, in general, the Interchange Agreement is designed to share system-related production and transmission cost between the two operating companies, NSPM and NSPW. The intent of this sharing is to represent these two company systems as a single joint operation. To equalize the costs across this joint system, each operating company bills the other operating company for their share of the joint costs in general using energy requirements as the basis for sharing variable costs and peak demand as the basis for sharing capital related and other fixed costs.

Q. WHAT SPECIFIC COMPONENTS ARE IMPACTED BY THIS SHARING IN THE 2021-2023 MYRP COSS?

A. The NSPM billings to NSPW for the sharing of NSPM costs appear as other revenues in the MYRP Forecast cost of service. The NSPW billings to NSPM for the sharing of NSPW costs appear as either production or transmission expenses in the MYRP Forecast cost of service. Also, any adjustments being proposed in the case that pertain to production or transmission are developed using the same mechanics.

VI. UTILITY AND JURISDICTIONAL ALLOCATIONS

Q. WHAT TOPICS DO YOU DISCUSS IN THIS SECTION OF YOUR TESTIMONY?

A. In this section I will:

- explain, at a high level, why it is necessary for the Company to allocate costs among its affiliates and between the jurisdictions in which it does business;
- describe the utility and jurisdictional allocations that are used in determining the revenue requirement;
- explain the circumstances of the elimination of the separate Wholesale Jurisdiction, the circumstances that led to the loss of full-service

wholesale customers, and the effect of those events, including the results of the Company's Wholesale Customer Study.

Q. WHY IS IT NECESSARY TO ASSIGN OR ALLOCATE COSTS BETWEEN NSPM AND ITS AFFILIATES?

A. Whenever services or facilities are shared between NSPM and an affiliate, it is necessary that the appropriate costs related to those services or facilities be assigned or allocated to the appropriate entity. Company witness Mr. Ross L. Baumgarten, in his Direct Testimony, explains the allocations for services and facilities shared between NSPM and an affiliate. The cost assignment and allocation principles are unchanged from those used by the Company in the most recent Minnesota electric rate case. Additional information regarding this process and the reason for selecting a particular allocator is also included in the Cost Assignment and Allocation Manual (CAAM) submitted with this application as Mr. Baumgarten's Exhibit___(RLB-1), Schedule 3.

Q. IS IT NECESSARY TO ASSIGN OR ALLOCATE COSTS BETWEEN NSPM'S ELECTRIC AND GAS UTILITIES?

A. Yes. NSPM operates both an electric utility and a gas utility. Therefore, it is necessary that the appropriate costs related to those services or facilities be assigned or allocated to the appropriate utility.

Q. IS IT NECESSARY TO ASSIGN OR ALLOCATE COSTS BETWEEN JURISDICTIONS?

A. Yes. The Company operates in three jurisdictions: Minnesota, North Dakota, and South Dakota. Thus, it is necessary to allocate or assign costs appropriately between jurisdictions. Previously, costs were allocated or assigned to four jurisdictions: Minnesota, North Dakota, South Dakota, and Wholesale. Beginning in 2014, however, the Company has no full requirements wholesale customers. Therefore, since 2014, costs are allocated between the Company's three retail jurisdictions.

Q. HOW ARE COSTS ASSIGNED AND ALLOCATED?

A. The expense budgets relied upon to develop test-year income statement items were generally prepared on a functional basis (*i.e.* Production, Transmission, Distribution, Customer Accounts, Customer Information, Sales, Administrative and General). These functional amounts are directly assigned to the Minnesota jurisdiction electric utility operations where appropriate or allocated based on cost causation.

Detailed records are maintained on a functional basis (*i.e.* Production, Transmission, Distribution, etc.). The capital budgets, from which the projected plant balances in rate base were developed, are also prepared on a functional basis. These functional amounts are assigned to the appropriate jurisdiction directly or allocated based on the use of such assets in providing electric service in a particular jurisdiction and the underlying elements of cost causation.

Generally, all production plant is allocated to jurisdiction using the jurisdictional demand allocator, with the exception of wind projects, which are allocated using the jurisdictional energy allocator. In addition, production costs are shared with NSPW under the terms of the Interchange Agreement. The Interchange Agreement tariff approved by FERC specifically requires fixed production assets to be allocated between NSPM and NSPW based on demand.

Fixed production O&M expense is allocated using the jurisdictional demand allocator. In addition, fixed production O&M expense is shared with NSPW under the terms of the Interchange Agreement. The Interchange Agreement requires these costs to be allocated between NSPM and NSPW based on demand.

All variable production O&M expense is allocated to jurisdiction using the jurisdictional energy allocator. In addition, variable production O&M expense is shared with NSPW under the terms of the Interchange Agreement. The Interchange Agreement requires these costs to be allocated between NSPM and NSPW based on energy.

Mr. Baumgarten further explains assignment and allocation of costs in his Direct Testimony.

Q. HOW ARE THESE ALLOCATION FACTORS DEVELOPED?

A. A summary and description of the allocation factors used to allocate expenses and capital items to the Minnesota jurisdictional electric operations income statement and rate base is contained in Volume 3, Section II.3, Required Financial Information, Rate Base Schedules, Tab E Rate Base Jurisdictional Allocation Factors, and Section II.4, Required Financial Information, Operating Income Schedules, Tab F, Operating Income Jurisdictional Allocation Factors. Plant investments are accounted for in the manner prescribed by the FERC Uniform System of Accounts. Mr. Baumgarten also further explains the development of allocation factors in his Direct Testimony.

Q. HOW ARE FUEL AND PURCHASED POWER COSTS ALLOCATED?

A. Fuel and purchased energy costs are allocated to each jurisdiction using the jurisdictional energy allocator. Purchased demand costs are allocated to each jurisdiction using the jurisdictional demand allocator. In addition, fuel and purchased power costs are shared with NSPW under the terms of the Interchange Agreement. The Interchange Agreement requires fuel and purchased energy costs to be allocated between NSPM and NSPW based on energy. Purchased demand costs are allocated between NSPM and NSPW using demand.

Q. HOW ARE COMPENSATION- AND BENEFIT-RELATED RATE CASE ADJUSTMENTS ALLOCATED?

A. Compensation- and benefit-related rate case adjustments are allocated to jurisdictions using a weighted allocator based on all expenses in FERC 926 Employee Pensions and Benefits. Expenses in FERC 926 were allocated following the CAAM submitted with this application as Exhibit ___ (RLB-1), Schedule 3 to Mr. Baumgarten's Direct Testimony. An additional allocator was then created by determining each jurisdiction's portion of the Total NSPM expenses. The data used to calculate this allocator can be found in Volume 4, Section VII Budget Allocators, Tab B4, Other.

Q. WHAT IS THE WHOLESALE CUSTOMERS STUDY?

A. The Wholesale Customers Study shows all wholesale customers being served by the Company (including, but not limited to, full requirements, partial requirements, and market based wholesale customers), types of service being provided to each wholesale customer, costs, and revenues associated with each wholesale customer, and a clear showing either that wholesale costs are allocated out of the retail rate case or that the revenues are included in the retail rate case, for all services provided to wholesale customers.

Q. DOES THE WHOLESALE CUSTOMERS STUDY EXPLAIN WHY THE COMPANY NO LONGER ALLOCATES COSTS TO A WHOLESALE JURISDICTION?

A. Yes. Exhibit___(BCH-1) Schedule 14, Wholesale Customers Study, explains that all of our partial requirements and energy only wholesale customers are provided services pursuant to bilateral agreements, and also explains the treatment of costs and revenues related to services provided to those customers.

Q. WHAT SERVICES DOES THE COMPANY ANTICIPATE PROVIDING TO PARTIAL REQUIREMENTS WHOLESALE CUSTOMERS DURING THE MYRP FORECAST?

A. During the MYRP Forecast, the Company expects to provide services to wholesale customers in the following categories: asset based energy sales, asset based capacity sales, non-asset based energy and capacity sales, and other wholesale transactions (including interfacing and scheduling services, energy services agreements, and pass through charges).

Services to wholesale customers include interfacing between the customer and MISO, including providing balancing services. Revenues from these customers for services and asset based capacity are included in Other Revenues (*e.g.*, for balancing services). Sales of asset based energy are treated as asset based margins and passed through the fuel clause. We also provide some non-asset based services to these customers (energy and capacity sales using financial instruments). The margins from non-asset based transactions, as well as the fully allocated embedded costs related those activities, are treated as below-the-line activities not included in the retail revenue requirement.

Attachment A to Schedule 14, Wholesale Customers Study provides a list of the types of services provided, and the ratemaking treatment for each type of service. Attachment B to Schedule 14, Wholesale Customers Study provides a wholesale customer summary including all current agreements by customer and the expected revenues for the years 2021 to 2023.

Q. DOES THE WHOLESALE CUSTOMERS STUDY DEMONSTRATE THAT THE REVENUES ARE INCLUDED IN THE RETAIL RATE CASE?

A. Yes. After reviewing the services provided to our wholesale customers and the transactions associated with those services, the Company concludes that the ratemaking treatment of these transactions is consistent with past regulatory practice and the requirements of the Commission. Based on the treatment of these transactions, the Company believes that costs and revenues associated with wholesale customers are reflected properly in the test year.

VII. ANNUAL ADJUSTMENTS TO THE MYRP

Q. WHAT TOPICS DO YOU ADDRESS IN THIS SECTION OF YOUR TESTIMONY?

A. In this section of my testimony, I explain adjustments that affect our proposed MYRP Forecast revenue requirement. These adjustments were identified during our review of the 2021 budget and preparation for this case. An individual adjustment may be related to a previous Commission Order, reflect Commission policy or traditional ratemaking treatment, or may be proposed to address a situation particular to this rate case. In this section, I provide details related to each adjustment and explain why each is necessary in order to present a representative level of rate base or costs in the MYRP Forecast. I also identify where another Company witness provides information to explain and support the adjustment.

Q. HOW ARE THESE ADJUSTMENTS PRESENTED IN YOUR TESTIMONY?

A. First, I present traditional adjustments consistent with treatment in prior cases and existing Commission Policy Statements (Precedential Adjustments) and rate case adjustments specific to this particular case (Rate Case Adjustments). Next, I explain the various amortizations affecting the test year (Amortizations), the removal of certain costs and revenues being recovered through riders (Rider Removals), a group of adjustments that are the result of secondary dynamic calculations in the cost of service model (Secondary COS Calculations), and certain adjustments that may be necessary for Rebuttal Testimony in this proceeding.

Q. PLEASE LIST THE 2021-2023 MYRP ADJUSTMENTS.

A. The following adjustments were made to rate base and the income statement where applicable. Rate base adjustments are shown on Schedules 10a-10c, Rate Base Adjustment Schedule. Income statement (revenue requirement) adjustments are shown on Schedules 11a-11c, 2021-2023 Income Statement Adjustment Schedule. As a general note, all revenue requirements shown on Schedules 11a-11c, are net of Interchange Agreement billings, where applicable, and capital related revenue requirements are shown calculated at the last authorized rate of return. Exhibit___(BCH-1), Schedule 12 MYRP Adjustment Summary provides adjustment amounts for the MYRP. Precedential Adjustments are set forth in Exhibit ___ (BCH-1), Schedule 13 and Table 8 below.

<u>Rate Case Adjustments</u>

1) CIP Approved Program Costs
2) CIP Incentive
3) Depreciation Study: Remaining Life
4) Depreciation Study: TD&G
5) Incentive Compensation
6) Pension: Deferred Expense
7) Pension: Extend Deferral
8) Transmission ROE

<u>Amortizations</u>

9) Aurora Deferral
10) Electric Vehicle Amortization
11) Income Tax Tracker Amortization
12) LED Street Lighting Amortization
13) NOL Tax Reform Regulatory Amortization
14) Prairie Island EPU Deferred Costs
15) Rate Case Expense
16) Sherco 3 Depreciation

Rider Removals

17) Renewable Connect Removal and Avoided Capacity

18) RES Rider

19) TCR Rider

20) Windsource Removal and Avoided Capacity

Secondary Cost of Service Calculations

21) ADIT Pro-Rate – IRS Required

22) Cash Working Capital

23) Change in Cost of Capital

24) Net Operating Loss

A. Precedential Adjustments

Q. PLEASE LIST THE PRECEDENTIAL TEST YEAR ADJUSTMENTS INCLUDED IN THE REVENUE REQUIREMENT CALCULATION.

A. Table 8 below is a list of Precedential Adjustments and their associated revenue requirement impact, based on past rate case precedent and Commission policy:

Table 8

Precedential Adjustments

Adjustment	2021 Test Year	2022 Plan Year	2023 Plan Year	Workpaper Reference
NSPM-Advertising (Trad)	($3,090,791)	($3,121,652)	($3,152,821)	WP-A1
NSPM-Assn Dues (Trad)	(288,989)	(286,758)	(286,037)	WP-A2
NSPM-Aviation	(2,792,391)	(2,151,518)	(2,579,061)	WP-A3
NSPM-Chamber of Commerce Dues	184,812	184,812	184,812	WP-A4
NSPM-Customer Deposits - A&G Expense (Trad)	22,560	22,560	22,560	WP-A5
NSPM-Donations (Trad)	615,749	616,933	1,428,788	WP-A6
NSPM-Econ Dev Donations (Trad)	94,157	94,157	94,157	WP-A7
NSPM-Econ Develop (Trad)	(81,725)	(81,725)	(81,725)	WP-A8
NSPM-Employee Expenses	(1,569,250)	(1,512,319)	(1,562,482)	WP-A9
NSPM-Foundation Admin	(31,280)	(31,923)	(32,884)	WP-A10
NSPM-Investor Relations	(307,739)	(312,377)	(317,246)	WP-A11
NSPM-Monticello EPU Commission Order No Return	(10,349,841)	(9,106,974)	(7,867,132)	WP-A12
NSPM-Nobles Disallowed Assets	(173,156)	(159,101)	(145,076)	WP-A13
NSPM-Nuclear Retention Removal	(558,680)			WP-A14
NSPM-Other Revenue to 3 Year Average Adj	(1,813,527)	(1,588,690)	(783,097)	WP-A15
NSPM-Pension Discount Rate Int	(173,201)	(174,077)	(175,015)	WP-A16
NSPM-Pension Non-Qual Restoration Removal	(635,826)	(629,083)	(619,290)	WP-A17
NSPM-Pension Non-Qual SERP Removal	(241,513)	(165,398)	(124,179)	WP-A18
NSPM-Pension Retiree Medical	(248,435)	(217,659)	(190,088)	WP-A19
NSPM-Pension Tracker Difference	9,177	(49,670)	(18,648)	WP-A20
NSPM-Remove Asset Trading	18,954,169	18,954,169	18,954,169	WP-A21
NSPM-Remove NonAsset Trading	7,887,154	11,528,276	10,600,837	WP-A22
NSPM-Remove NonAsset Trading Fully Allocated Costs	(2,595,578)	(2,557,083)	(2,559,136)	WP-A23
Sub-Total Precedential	$2,815,856	$9,254,901	$10,791,408	

Q. HOW DOES THE COMPANY PROVIDE SUPPORT FOR THESE PRECEDENTIAL ADJUSTMENTS?

A. Treatment of these precedential adjustments has not changed from the Commission's Order in the Company's previous two completed electric rate cases (Docket Nos. E002/GR-13-868 and E002/GR-15-826). As such, the

Company has provided the adjustments themselves in Schedules to my Direct Testimony, and support for these adjustments, including a detailed description of each adjustment and supporting materials, in the workpapers identified in Table 8 above. This organization is intended to facilitate the review of and full support for each adjustment within the identified workpaper.

Q. WHAT IMPACT DO THESE PRECEDENTIAL ADJUSTMENTS HAVE ON THE COMPANY'S ABILITY TO RECOVER ITS TOTAL COSTS OF SERVICE?

A. Regulatory treatment of these precedential adjustments, combined with the incentive compensation adjustments discussed below, decrease our recovery of our costs of service by approximately $33 to $36 million as shown in Table 9 below. The Company expects to incur these costs over the three years of the MYRP, so the cumulative cost to the Company is $103 million over the three-year MYRP.

Table 9

Regulatory Disallowances

Adjustment	**2021 Test Year**	**2022 Plan Year**	**2023 Plan Year**	**Total**
Total Precedential Less Asset and Non-Asset Trading	($21,429,889)	($18,670,461)	($16,204,463)	($56,304,813)
Total Incentive	(14,161,994)	(15,521,389)	(16,470,775)	(46,154,158)
Total Disallowances	($35,591,883)	($34,191,850)	($32,675,238)	($102,458,971)

Q. HOW IS THE COMPANY INCORPORATING THESE ADJUSTMENTS INTO THE MYRP FORECAST?

A. These 23 precedential adjustments are combined in one column matching the Total row in Table 8 above to Schedules 11a–11c, 2021-2023 Income Statement Adjustment Schedule. In total, these precedential adjustments represent a decrease in our rate request compared to our budgeted costs. The detail of the precedential adjustments in bridge schedule format can be seen in Schedule 13, Precedential Adjustment Detail. In addition, as noted above, each respective workpaper referenced above contains a detailed description of the adjustment, including the past precedent and related Commission Orders or Policy Statements.

Q. WHY ARE ASSET AND NON-ASSET TRADING PRECEDENTIAL ADJUSTMENTS NOT INCLUDED IN TABLE 9 ABOVE?

A. Asset and Non-Asset trading margins are not considered in the determination of base rates, and; therefore, the adjustments to remove these margins do not affect the revenue requirement. Table 9 represents adjustments in this rate case that either increase or decrease the revenue requirements. In future rate cases, the Company would like to include all Asset and Non-Asset Trading removals as part of base data (rather than show a separate adjustment) to better align base costs and regulatory treatment.

Q. WITH RESPECT TO ECONOMIC DEVELOPMENT COSTS, HAS THE COMPANY PERFORMED A COST BENEFIT ANALYSIS TO DETERMINE THAT THE BENEFITS OF THE ECONOMIC DEVELOPMENT PROGRAMS EXCEED THEIR COST TO RETAIL CUSTOMERS?

A. Yes. We completed a cost-benefit analysis supporting the inclusion of economic development costs in the MYRP Forecast. Exhibit___(BCH-1), Schedule 16, Economic Development Cost-Benefit Analysis, Attachments A and B provide the potential revenue and cost impacts of the addition of one commercial/industrial customer to NSPM's electric system due to economic development programs. The results indicate that the investments made by the Company to support economic development in our community have the potential to provide value to customers as soon as the second year.

B. Rate Case Adjustments

1) CIP Approved Program Costs

Q. PLEASE DESCRIBE THE CIP APPROVED PROGRAM LEVELS ADJUSTMENT.

A. The MYRP Forecast CIP expenses and corresponding revenues have been set at the 2021 level of $125.6 million as proposed in Docket E,G002/CIP-20-473.

Because we make corresponding adjustments to both revenue and expense, this adjustment has no impact on the MYRP Forecast deficiency, as shown on:

- Schedule 11, page 1, row 41, column 7;
- Schedule 12, page 1, row 28, columns 5 through 7;
- Volume 4, Section VIII Adjustments, Tab A24, CIP Approved Program Levels.

I note that the decision of the Deputy Commissioner of the Minnesota Department of Commerce in Docket No. E,G002/CIP-20-473 on the Company's 2021-2023 CIP Triennial Plan is expected to be issued November 12, 2020. However, as previously noted, the decision would not affect the revenue deficiency in this proceeding since any changes are made to both revenue and expense.

2) CIP Incentive

Q. PLEASE DESCRIBE THE CIP INCENTIVE ADJUSTMENT.

A. The CIP performance incentive is designed to compensate the Company for lost sales due to Company conservation efforts. The annual projected CIP performance incentive margin is included in the Other Revenue budget. The CIP performance margin is intended as an incentive to the Company and represents budgeted level in anticipation of achieving the CIP goals. An adjustment is necessary to remove the estimated performance margin from the MYRP Forecast. Failure to include this adjustment would flow the annual CIP performance incentive to customers by overstating operating revenues in the MYRP Forecast and; therefore, understating the revenue deficiency for the test year.

This adjustment impacts the MYRP Forecast revenue requirements by the amounts shown on:

- Schedule 11, page 1, row 41, column 8;
- Schedule 12, page 1, row 29, columns 5 through 7;
- Volume 4, Section VIII Adjustments, Tab A25, CIP Incentive.

3) Depreciation Study: Remaining Life

Q. PLEASE DESCRIBE THE DEPRECIATION STUDY: REMAINING LIFE ADJUSTMENT.

A. We have adjusted the 2021-2023 MYRP to include the impact of Docket No. E,G002/D-19-723. In the 2020 Remaining Lives filing, we proposed modifications to the remaining life of the Luverne Wind2Battery System; initial remaining lives and net salvage rates for Blazing Star II, Crowned Ridge, Freeborn, Dakota Range, Jeffers, Community Wind North, and Mower wind projects to be acquired or in-serviced during 2020 and 2021; and reserve reallocations to certain Steam and Other Production accounts. In addition to remaining life changes, we are also recommending updates to net salvage rates for electric production facilities based on a new five-year dismantling study. Support for these changes included provided by Mr. Moeller in his Direct Testimony.

This adjustment impacts the MYRP Forecast revenue requirements by the amounts shown on:

- Schedule 10, page 1, row 43, column 6;
- Schedule 11, page 1, row 41, column 9;
- Schedule 12, page 1, row 30, columns 5 through 7;
- Volume 4, Section VIII Adjustments, Tab A26, Depreciation Study: Remaining Life.

4) Depreciation Study: TD&G

Q. PLEASE DESCRIBE THE DEPRECIATION STUDY: TD&G ADJUSTMENT.

A. We have adjusted the 2021-2023 MYRP to include the impact of Docket No. E,G002/D-20-635. The new depreciation rates as proposed in the compliance filing would increase total Company depreciation expense by $1.8 million. We have proposed the new rates to be effective as of January 1, 2021. The 2020 docket is still pending final approval. However, the Test Year calculations assume that this filing will be adopted in its entirety. To the extent that these are not adopted per the filing, the Company will submit updates in rebuttal testimony. Support for these changes are provided by Mr. Moeller in his Direct Testimony.

This adjustment increases MYRP Forecast revenue requirements by the amounts shown on:

- Schedule 10, page 1, row 43, column 7;
- Schedule 11, page 1, row 41, column 10;
- Schedule 12, page 1, row 31, columns 5 through 7;
- Volume 4, Section VIII Adjustments, Tab A27, Depreciation Study: TD&G.

5) Incentive Compensation

Q. PLEASE DESCRIBE THE INCENTIVE COMPENSATION ADJUSTMENT.

A. We have adjusted MYRP Forecast costs to exclude the budgeted costs of: 1) the long-term incentive (LTI) compensation other than those portions related to Company achievement of environmental goals and time-based employee retention incentives; 2) any non-corporate incentive plan costs; and 3) all Annual Incentive Plan amounts above 20 percent of each individual's base pay. Company witness Ms. Ruth K. Lowenthal discusses incentive compensation in her Direct Testimony.

This adjustment decreases MYRP Forecast revenue requirements by the amounts shown on:

- Schedule 11, page 1, row 41, column 11;
- Schedule 12, page 1, row 32-35, columns 5 through 7;
- Volume 4, Section VIII Adjustments, Tabs A28, AIP over Cap, A29, Environmental LTI, A30, Long Term Incentive Removal, and A31 Time Based LTI.

6) Deferred Pension Expense

Q. PLEASE DESCRIBE THE DEFERRED PENSION EXPENSE ADJUSTMENT.

A. This adjustment reflects the annual amount of the three-year amortization of the XES Plan cap cumulative deferred balance. The cumulative deferred balance is discussed Company witness Mr. Richard R. Schrubbe.

This adjustment impacts MYRP Forecast revenue requirements by the amounts shown on:

- Schedule 11, page 1, row 41, column 12;
- Schedule 12, page 1, row 36, columns 5 through 7;
- Volume 4, Section VIII Adjustments, Tab A32, Pension: Deferred Amortization.

7) Pension Extend Deferral

Q. PLEASE DESCRIBE THE PENSION EXTEND DEFERRAL ADJUSTMENT.

A. This adjustment reflects the Company's deferred pension expense difference related to extending the amortization period for unrecognized pension costs for the NSPM Plan from 10 to 20 years, and a "cap and defer" recovery of XES pension costs as approved in Docket No. E002/GR-13-868. Mr. Schrubbe discusses the pension extend deferral further in his Direct Testimony.

This adjustment impacts MYRP Forecast revenue requirements by the amounts shown on:

- Schedule 10, page 1, row 43, column 8;
- Schedule 11, page 1, row 41, column 13;
- Schedule 12, page 1, row 37, columns 5 through 7;
- Volume 4, Section VIII Adjustments, Tab A33, Pension: Extend Deferral.

8) Transmission ROE

Q. PLEASE DESCRIBE THE TRANSMISSION ROE ADJUSTMENT.

A. In his Direct Testimony, Mr. Benson describes the MISO ROE complaints and the potential test year impact on transmission revenues and expenses of any final decision from FERC related to the November 2013 and February 2015 MISO ROE Complaints. The Company believes a determination at FERC on this matter should not impact the retail jurisdiction, and the cost of capital should be treated consistently across our rate base; therefore, we are proposing this adjustment to calculate the net transmission revenue credit using the ROE approved by the Commission in this case. For purposes of this filing, the adjustment was prepared based on the last authorized ROE of 9.06 percent for the TCR Rider.[7] In final compliance, the Company will make an adjustment to reflect the final authorized ROE in this case.

This adjustment includes the impact on Attachment O, GG and MM from the MISO Transmission Formula Rate which will be partially offset in the TCR Rider removal of MISO RECB revenue and expenses discussed in Sections VII and VIII of my testimony. This adjustment impacts the MYRP Forecast revenue requirements by the amounts shown on:

- Schedule 11, page 1, row 41, column 14,
- Schedule 12, page 1, row 38, columns 5 through 7,
- Volume 4, Section VIII Adjustments, Tab A34, Transmission ROE.

C. Amortizations

9) Aurora Deferral

Q. PLEASE DESCRIBE THE AURORA DEFERRAL EXPENSE AMORTIZATION.

A. The Commission's Order in Docket No. E-002/M-15-330 approved the PPA between Xcel Energy and Aurora Distributed Solar, LLC. This resource was disputed by the South Dakota Public Utilities Commission (SDPUC) in Docket EL16-037 and resulted in recovery limited to an energy proxy price (derived from the system average cost of fuel and purchased power), with no capacity component. The Company is, therefore, requesting authorization to recover the difference between the contracted PPA and the proxy price through this

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[7] In Docket No. E002/M-17-797 the Minnesota Public Utilities Commission ordered the following: Xcel Energy must "use an ROE of 9.06 percent in all electric dockets filed by the Company that require an ROE until the Commission issues an Order in the Company's next rate case authorizing a different ROE." September 27, 2019 ORDER AUTHORIZING RIDER RECOVERY, SETTING RETURN ON EQUITY, AND SETTING FILING REQUIREMENTS, p. 8.

case. Mr. Chamberlain discusses this request in his Direct Testimony. We are requesting recovery of these costs over the two-year period from 2021-2022, along with the ability to pass this cost to Minnesota customers through the FCA on a going forward basis beginning January 1, 2023.

Q. PLEASE DESCRIBE HOW THE AURORA DEFERRAL EXPENSE AMORTIZATION ADJUSTMENT WAS CALCULATED.

A. This adjustment reflects actual PPA costs through June 30, 2020 and budgeted PPA costs through December 31, 2022 in excess of the energy proxy price referenced above from January 1, 2017, the date the South Dakota Public Utilities Commission denied recovery, to January 1, 2023, the date the Company requests to shift recovery to the FCA. The total accumulated balance over the six years is then amortized over 24 months.

This adjustment impacts the MYRP Forecast revenue requirements by the amounts shown on:

- Schedule 10, page 1, row 43, column 9;
- Schedule 11, page 2, row 41, column 15;
- Schedule 12, page 1, row 41, columns 5 through 7;
- Volume 4, Section VIII Adjustments, Tab A35, Aurora Deferral.

10) Electric Vehicle Amortization

Q. PLEASE DESCRIBE THE ELECTRIC VEHICLE AMORTIZATION.

A. The Commission's Order in Docket No. E002/M-15-111 approved the Residential Electric Vehicle Charging Tariff where the Company will maintain separate accounting of the information, education, advertising and promotion costs associated with electric vehicles by deferring the costs to a tracker account. The Company is, therefore, requesting authorization to recover the electric vehicle deferral costs over the MYRP Forecast.

This adjustment impacts the MYRP Forecast revenue requirements by the amounts shown on:

- Schedule 10, page 1, row 43, column 10;
- Schedule 11, page 2, row 41, column 16;
- Schedule 12, page 1, row 42, columns 5 through 7;
- Volume 4, Section VIII Adjustments, Tab A36, Electric Vehicle Deferral.

11) Income Tax Tracker Amortization

Q. PLEASE DESCRIBE THE INCOME TAX TRACKER AMORTIZATION.

A. The Company has concluded tax audits with the IRS and the Minnesota Department of Revenue for tax years ended 2010 through 2016. As a result of the audits, the Company paid tax and interest on the disputed amounts. In the Company's 1992 rate case, Docket No. E002/GR-92-1185, and in Docket Nos. E002/M-93-1328, E002/M-04-1605, E002/M-05-1471 and E002/GR-12-961, the Commission authorized deferred accounting status of both tax credits and debits. Consistent with this precedent, we propose to collect this amount over the MYRP period.

This adjustment impacts the MYRP Forecast revenue requirements by the amounts shown on:

- Schedule 10, page 1, row 43, column 11;
- Schedule 11, page 2, row 41, column 17;
- Schedule 12, page 1, row 43, columns 5 through 7;
- Volume 4, Section VIII Adjustments, Tab A37, Income Tax Tracker.

12) LED Street Lighting Amortization

Q. PLEASE DESCRIBE THE LED STREET LIGHTING AMORTIZATION.

A. The Commission's Order in Docket No. E002/GR-15-826 approved deferral of the LED Street Lighting revenue requirements, and the Commission's March 13, 2020 Order in Docket No. E002/19-688 (Order Approving True-Ups) approved that deferral to continue for an additional year. The Company is, therefore, requesting authorization to recover a total of $0.582 million in LED Street Lighting costs over the MYRP Forecast.

This adjustment impacts the MYRP Forecast revenue requirements by the amounts shown on:

- Schedule 10, page 1, row 43, column 12;
- Schedule 11, page 2, row 41, column 18;
- Schedule 12, page 1, row 44, columns 5 through 7;
- Volume 4, Section VIII Adjustments, Tab A38, LED Street Lighting.

13) NOL Tax Reform Regulatory Amortization

Q. PLEASE DESCRIBE THE NOL TAX REFORM REGULATORY AMORTIZATION.

A. The Commission's Order in Docket No. E,G999/CI-17-895 approved the Company's proposed amortization level included in the TCJA refund calculation. This is being amortized over 23 years.

The adjustment impacts the MYRP Forecast revenue requirements by the amounts shown on:

- Schedule 10, page 1, row 43, column 13;
- Schedule 11, page 2, row 41, column 19;
- Schedule 12, page 1, row 45, columns 5 through 7;
- Volume 4, Section VIII Adjustments, Tab A39, NOL Tax Reform ADIT ARAM.

14) Prairie Island EPU Deferred Costs

Q. PLEASE EXPLAIN THE ADJUSTMENT NEEDED TO RECOVER THE PRAIRIE ISLAND EXTENDED POWER UPRATE (EPU) DEFERRED COSTS.

A. The Commission's Order in Docket No. E002/GR-13-868 approved the recovery of the abandoned Prairie Island EPU project costs over the remaining life of the plant through an amortization expense. The Order also approved including this unrecovered investment in rate base but limited the return on rate base related to this project to the weighted cost of debt.

The amortization and rate of return adjustment impacts the MYRP Forecast revenue requirements by the amounts shown on:

- Schedule 10, page 1, row 43, column 14;
- Schedule 11, page 2, row 41, column 20;
- Schedule 12, page 1, row 46, columns 5 through 7;
- Volume 4, Section VIII Adjustments, Tab A40, PI EPU Recovery.

Q. PLEASE DESCRIBE THE PRAIRIE ISLAND EPU ADJUSTMENTS INCLUDED IN THE 2021-2023 MYRP COSS IN MORE DETAIL.

A. First, the various rate base and income statement components related to the amortization of this deferred cost are input as an adjustment to the cost of service. This results in the calculation of the overall revenue requirement associated with this project. Embedded in these calculations is a computation of return on rate base at the overall weighted cost of capital (debt and equity). To adjust for the ordered weighted cost of debt return requirement, the Company computes the revenue requirements associated with the weighted cost of equity and includes the result of this calculation as Other Revenues to reduce the deficiency by this amount. If return component weighted costs are adjusted during this case, this adjustment will require a recalculation to reflect those changes.

15) Rate Case Expense

Q. PLEASE DESCRIBE THE RATE CASE EXPENSE AMORTIZATION.

A. The Company is requesting authorization to recover a total of $5.270 million in rate case costs over the MYRP Forecast. We are requesting recovery of these costs over the three-year period 2021-2023, consistent with our multi-year rate plan.

Q. PLEASE DESCRIBE HOW RATE CASE EXPENSE WAS ESTIMATED.

A. The rate case expense budget was developed by first reviewing actual expenses incurred in our 2015 electric rate case. We built the 2021 rate case budget based upon a combination of our plans for outside experts, expected regulatory and legal fees, and estimates for administrative costs such as required notices.

Q. ARE ANY OTHER EXPENSES INCLUDED IN THE RATE CASE EXPENSE AMORTIZATION?

A. Yes. The rate case expense amortization also includes costs incurred in development of the Company's 2020 rate case (Docket No. E002/GR-19-564) which was withdrawn. The Company included for recovery costs incurred for work related to the 2020 rate case that could be repurposed in the development of the 2021 rate case, including a portion of outside legal and consultant fees.

Q. HOW IS THIS ADJUSTMENT IMPACTING THE MYRP FORECAST REVENUE REQUIREMENTS?

A. This adjustment impacts the MYRP Forecast revenue requirements by the amounts shown on:

- Schedule 11, page 2, row 41, column 21;
- Schedule 12, page 1, row 47, columns 5 through 7;
- Volume 4, Section VIII Adjustments, Tab A41, Rate Case Expenses.

16) Sherco 3 Depreciation

Q. PLEASE DESCRIBE THE SHERCO 3 DEPRECIATION DEFERRAL AMORTIZATION.

A. The Commission's Order in Docket No. E002/GR-12-961 required the Company to defer the depreciation expense incurred for Sherco 3 during the extended repair outage following the 2011 catastrophic event and amortize it over the remaining life of the plant.

The adjustment impacts the MYRP Forecast revenue requirements by the amounts shown on:

- Schedule 10, page 1, row 43, column 15;
- Schedule 11, page 2, row 41, column 22;
- Schedule 12, page 1, row 48, columns 5 through 7;
- Volume 4, Section VIII Adjustments, Tab A42, Sherco 3 Depr Deferral.

D. Rider Removals

Q. PLEASE DESCRIBE THE PURPOSE OF THE RIDER REMOVALS.

A. As previously noted, the Company is removing from base rates all costs it is continuing to recover through riders. Rider costs removed from base rates include costs for rider-eligible projects that are ongoing after the conclusion of the test year; certain types of variable costs; and costs for certain ongoing rider programs. Conversely, some portions of rider-eligible projects – such as internal labor – remain in base rates because the Commission does not consider those project components to be rider-eligible. The discussion below demonstrates that the Company is appropriately removing rider costs from base rates.

Q. FOR RIDER-ELIGIBLE PROJECTS WITH AN INTERNAL LABOR COMPONENT, HOW DOES THE COMPANY CALCULATE THE INTERNAL LABOR COMPONENT THAT WILL REMAIN IN BASE RATES?

A. The Company determines the percentage of total CWIP expenditures on a project to date that consists of internal labor and applies that percentage to the forecasted CWIP expenditures. From an O&M perspective, the Company reviews the budget data and identifies the internal labor cost types. The rider removal adjustment excludes these components from project costs, thereby leaving the internal labor in base rates.

*17) Renewable*Connect Removal and Avoided Capacity*

Q. PLEASE DESCRIBE THE RENEWABLE*CONNECT (R*C) REMOVAL AND AVOIDED CAPACITY ADJUSTMENT.

A. The Renewable*Connect program is a stand-alone retail service program with discrete revenues, purchase power contracts, and operating expenses. We have excluded Renewable*Connect revenues and associated expenses from our MYRP Forecast revenue requirements determination.

Renewable*Connect is a voluntary renewable energy program that gives customers an option to purchase renewable energy to meet all of their energy needs. Customers can choose to subscribe to a five- or ten-year term, or on a month-to-month basis. A customer subscribing to Renewable*Connect is charged the Renewable*Connect price in lieu of the fuel clause pricing, which is based on the Company's current mix of energy resources.

Including Renewable*Connect as part of a utility's resource mix means that the utility avoided building or purchasing from other sources. The kWh cost of renewable energy purchased by a utility includes a capacity factor or value which would otherwise have been included in the utility's base rates and paid by all customers because all customers benefit from the capacity. This capacity credit is subtracted from the Renewable*Connect rate because it is a cost that should be shared by all customers, rather than only by Renewable*Connect customers. The Direct Testimony of Company witness Mr. Michael A. Peppin further supports the development of the Renewable*Connect avoided capacity credit.

The net of these adjustments impacts the MYRP Forecast revenue requirements by the amounts shown on:

- Schedule 11, page 2, row 41, column 23;
- Schedule 12, page 1, row 51, columns 5 through 7;
- Volume 4, Section VIII Adjustments, Tab A43, Renewable Connect.

18) RES Rider

Q. IS THE COMPANY PROPOSING CONTINUED USE OF THE RES RIDER DURING THE MYRP?

A. Yes. As I describe in detail in Section VIII, Costs Recovered in Riders, we propose continued use of the RES Rider during the MYRP for the projects that will not be placed in-service as of December 31, 2020.

Q. PLEASE DESCRIBE THE RES RIDER REMOVAL ADJUSTMENT.

A. The RES Rider removal adjustment removes all costs and PTCs from the test year jurisdictional cost of service for the projects that we propose will stay in the rider after the implementation of final rates in this case. The RES Rider test year adjustment ensures no double recovery of these costs.

For PTCs related to energy production at other Company-owned wind farms, currently and proposed to be included in base rates, we propose to continue the true-up to actual PTCs in the RES Rider. These wind farms include Borders Wind Farm, Pleasant Valley Wind Farm, Courtenay Wind Farm, Foxtail Wind Farm, Blazing Star I Wind Farm, Lake Benton Wind Farm, Blazing Star II Wind Farm, Crowned Ridge Wind Farm, Jeffers Wind Farm, Community Wind North Wind Farm and Mower Wind Farm. Finally, should the Company sell any Renewable Energy Credits (RECs), the proceeds from those sales would be shared with customers through the RES Rider.

Q. WHAT COSTS ARE INCLUDED IN THE RES RATE RIDER REMOVAL ADJUSTMENT?

A. This adjustment includes project costs and PTCs for the Freeborn Wind Farm and Dakota Range Wind Farm and RES Rider present revenue associated with these items that are proposed to be included in the RES Rider after the implementation of final rates. Costs or revenues associated with the PTC true-up and RECs sales occur only on an actual basis and, as such, require no test year adjustment.

This adjustment decreases the MYRP Forecast rate base by $376.4 million in 2021, as well as $428.8 million and $376.2 million in years 2022 and 2023 respectively. The adjustment has a net zero impact on the MYRP Forecast revenue requirements, as we expect full recovery in the RES rider. Support for these amounts can be found on:

- Schedule 10, page 1, row 43, column 16;
- Schedule 11, page 2, row 41, column 24;
- Schedule 12, page 1, row 52, columns 5 through 7;
- Volume 4, Section VIII Adjustments, Tab A44, Rider: RES.

19) TCR Rider

Q. IS THE COMPANY PROPOSING CONTINUED USE OF THE TCR RIDER DURING THE MYRP?

A. Yes. As I describe in detail in Section VIII, Costs Recovered in Riders, we propose continued use of the TCR Rider during the MYRP for the projects that will not be placed in service as of December 31, 2020 and MISO RECB Schedule 26 and 26A revenues net of expenses.

Q. PLEASE DESCRIBE THE TCR RIDER REMOVAL ADJUSTMENT.

A. The TCR Rider removal adjustment removes all costs and revenues (other than internal labor) from the MYRP Forecast jurisdictional cost of service for the Advanced Distribution Management System (ADMS), Advanced Metering Infrastructure (AMI), Field Area Network (FAN), Time of Use (TOU) Pilot, LoadSeer, and Huntley-Wilmarth projects, as well as MISO RECB Schedule 26 and 26A net revenues. We proposed to include these project costs and revenues in the TCR Rider, and to continue cost recovery for these projects in the rider after the implementation of final rates in this case. The TCR Rider MYRP Forecast adjustment ensures no double recovery of these costs.

This adjustment decreases the MYRP Forecast rate base by $89.922 million in 2021, as well as $175.226 million and $286.217 million in years 2022 and 2023 respectively. The adjustment has a net zero impact on the MYRP Forecast revenue requirements, as we expect full recovery in the TCR Rider. Support for these amounts can be found on:

- Schedule 10, page 1, row 43, column 17;
- Schedule 11, page 2, row 41, column 25;
- Schedule 12, page 1, row 53, columns 5 through 7;
- Volume 4, Section VIII Adjustments, Tab A45, Rider: TCR.

Q. DOES THE COMPANY COORDINATE THE TCR RIDER REMOVAL WITH ITS TCR RIDER FILINGS?

A. Yes. With each filing, we work to ensure coordination between the rate case test year and our TCR Rider filing. However, we note that rate case and rider filings calculate revenue requirements using different rate base averaging methodologies, and certain inputs in the rider are required to use historically-approved values. Therefore, even though the underlying data is aligned, there are typically variances in the revenue requirement calculations.

20) Windsource Removal and Avoided Capacity

Q. PLEASE DESCRIBE THE WINDSOURCE REMOVAL AND AVOIDED CAPACITY ADJUSTMENT.

A. The Windsource program is a stand-alone retail service program with discrete revenues, purchase power contracts, and operating expenses. We have excluded Windsource revenues and associated expenses from our MYRP Forecast revenue requirements determination.

Including wind energy generation as part of a utility's resource mix means that the utility avoided building or purchasing from other sources. The kWh cost of wind energy purchased by a utility includes a capacity factor or value which would otherwise have been included in the utility's base rates and paid by all customers because all customers benefit from the capacity. This capacity credit is subtracted from the Windsource rate because it is a cost that should be shared by all customers, rather than only by Windsource customers. The Direct Testimony of Company witness Mr. Michael A. Peppin further supports the development of the Windsource avoided capacity credit.

The net of these adjustments impacts the MYRP Forecast revenue requirements by the amounts shown on:

- Schedule 11, page 2, row 41, column 26;
- Schedule 12, page 1, row 54, columns 5 through 7;
- Volume 4, Section VIII Adjustments, Tab A46, Windsource.

E. Secondary Cost of Service Calculations

21) ADIT Pro-Rate – IRS Required

Q. PLEASE DESCRIBE THE ADIT PRO-RATE 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 pro-rated schedule for the extent average accumulated deferred income taxes 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 MYRP 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 pro-ration 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 pro-rate method to only the forecast entries to this balance. During final validation on the ADIT pro-rate calculation, we identified that the pro-rate factor used in our model had inadvertently included a double average of the factor. This has been corrected in our interim rate petition and is discussed further in Section F below. Support for this calculation is included in Exhibit___(BCH-1), Schedule 19, ADIT Pro-Rate. The IRS requirements for this adjustment are described in more detail in the Direct Testimony of Mr. Moeller.

The adjustment impacts the MYRP Forecast revenue requirements by the amounts shown on:

- Schedule 10, page 1, row 43, column 18;
- Schedule 11, page 2, row 41, column 27;
- Schedule 12, page 1, row 57, columns 5 through 7;
- Volume 4, Section VIII Adjustments, Tab A47, ADIT Prorate for IRS.

22) Cash Working Capital

Q. PLEASE DESCRIBE THE CASH WORKING CAPITAL ADJUSTMENT BEING MADE AS A SECONDARY CALCULATION.

A. As discussed earlier in Section IV.E, Other Rate Base, the Company has incorporated a secondary calculation to apply the various revenue lead days and expense lag days to the various income statement components to result in the appropriate cash working capital rate base adjustment. The adjustment impacts the MYRP Forecast revenue requirements by the amounts shown on:

- Schedule 10, page 1, row 43, column 19,
- Schedule 11, page 2, row 41, column 28,
- Schedule 12, page 1, row 58, columns 5 through 7,
- Volume 4, Section VIII Adjustments, Tab A48, Cash Working Capital Adjustment.

23) Change in Cost of Capital

Q. PLEASE DESCRIBE THE IMPACT OF THE CHANGE IN THE COST OF CAPITAL ADJUSTMENT.

A. The change in the cost of capital adjustment is the effect of the changes in the overall cost of capital between the cost of capital (also referred to as the overall rate of return, or ROR) being requested in this case for each year of the MYRP and the effective cost of capital authorized in Docket No. E002/GR-15-826. Table 10 below provides the requested rate of return in this case, and the difference in the rate of return for each year of the MYRP forecast relative to the effective 2019 rate of return of 7.08 percent authorized in Docket No. E002/GR-15-826.

Table 10

Proposed Rate of Return

	2020 Test Year	2021 Plan Year	2022 Plan Year
Proposed Rate of Return	7.35%	7.34%	7.33%
Difference relative to 7.08%	0.27%	0.26%	0.25%

On Schedules 11a-11c, 2021-2023 Income Statement Adjustment Schedule, the revenue deficiencies for the base data and all other adjustments are calculated at the 7.08 percent overall cost of capital. This adjustment calculates the required operating income resulting from the change in the overall cost of capital applied to the requested rate base.

We calculated the revenue deficiencies in this manner so that changes, if any, in the overall cost of capital that occurs during the duration of the rate case do not affect the revenue requirements for each adjustment. The adjustment reflects both the change in the stated ROE from 9.20 percent in our 2016-2019 MYRP to 10.20 percent (for final rates only) in this MYRP, as well as the changes in short-term and long-term debt.

The impact of these adjustments on the MYRP Forecast revenue requirements is shown on:

- Schedule 11, page 2, row 41, column 29;
- Volume 4, Section VIII Adjustments, Tab A50, Change in Cost of Capital.

24) Net Operating Loss

Q. PLEASE DESCRIBE THE COMPANY'S NET OPERATING LOSS POSITION.

A. The NSPM income tax determination was in a NOL position through 2018. This means that more deductions existed in the current period than are needed to bring current taxable income to zero. The Company still has federal tax credits that have been deferred and tracked for use in future periods. The Company worked with the Department on this issue, which resulted in a process for reporting these deferred balances and returning to customers the revenue requirement reduction associated with the utilization of these deferred balances in the form of a refund or as a reduction to base rates.

NOLs, unused tax credits, and the associated ratemaking treatment are discussed in detail earlier in my testimony in Section V. D. Taxes.

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

A. No. The Company was able to utilize the remainder of the deductions previously deferred and currently no DTA is generated in the MYRP. As noted previously in my 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 and added to rate base.

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 2021-2023 MYRP, but due to the amount of federal tax credits earned during the year, the DTA is increasing in each year of the MYRP. As noted previously in my 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 MYRP Forecast revenue requirements by the amounts shown on:

- Schedule 10, page 1, row 43, column 21;
- Schedule 11, page 2, row 41, column 30;
- Schedule 12, page 1, row 59, columns 5 through 7;
- Schedule 20, Net Operating Loss;
- Volume 4, Section VIII Adjustments, Tab A49, Net Operating Loss.

F. Rebuttal Adjustments

Q. WHAT INFORMATION DO YOU PROVIDE IN THIS SECTION?

A. In this section, I provide details related to adjustments we identified during our final quality assurance reviews performed just prior to this filing. These adjustments reflect small changes we believe necessary that we identified after we finalized our cost of service and rate design that we were not able to incorporate due to timing constraints. Consistent with prior rate cases, we propose to incorporate these adjustments into interim rates as applicable, and to update the MYRP Forecast revenue requirement for final rates when we file Rebuttal Testimony.

25) Cost of Capital

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

A. The Company's actual cost of capital data for July of 2020 became available after the cost of service was generated, which resulted in a small increase to components of the cost of capital in 2022 and 2023, and a one basis point change to the overall cost of capital in 2023. This change will increase the overall deficiency. This change is reflected in our interim rate revenue deficiency in our Interim Rate Petition, Schedule B, Part 3 of 3, page 1. Our cost of service will be corrected in Rebuttal for final rates.

26) FERC Audit

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

A. As discussed in the Direct Testimony of Mr. Baumgarten, the FERC audit of Xcel Energy Services Inc. ("XES") addressed the allocation of capital software to the Company's non-utility affiliates, which impacts the costs assigned to NSPM for the MYRP. 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 has been corrected to include the adjustment to remove a portion of the software applications allocated to NSPM related to this audit finding, and we will make the adjustment in Rebuttal Testimony for final rates. Support for this adjustment can be found in Volume 4, Section IX Interim, Tab Interim Adj 13, FERC Audit.

The FERC audit findings related to the NSPM FERC audit were incorporated into the transmission revenue and expense MYRP Forecast included in the rate case, to the extent they impacted the transmission formula development. The audit findings would have no financial impact on other rate base, so no Rebuttal adjustment is anticipated.

27) ADIT Pro-Rate for IRS

Q. PLEASE DESCRIBE THE REBUTTAL ADJUSTMENT RELATED TO ADIT PRO-RATE FOR IRS.

A. As discussed above, the Company was completing validation on the ADIT pro-rate calculation and identified that the pro-rate factor used in our model had inadvertently included a double averaging of the factor. This change will increase the overall deficiency by the amounts shown in Table 11 below. Our interim rate petition has been corrected to include the correct pro-rate factor, and we will correct the factor in Rebuttal Testimony for final rates. Support for this adjustment can be found in Volume 4, Section VIII Adjustments, Tab A47, ADIT Prorate for IRS.

Table 11

2020-2022 ADIT Pro-Rate ($ in millions)

2020 Test Year	2021 Plan Year	2022 Plan Year	Total
($1.549)	($0.266)	$0.318	($1.498)

28) RES Rider Revenues

Q. PLEASE DESCRIBE THE REBUTTAL ADJUSTMENT RELATED TO RES RIDER REVENUES.

A. As the Company was completing the interim adjustments to remove the projects recovered in the RES Rider during the interim rate period, we identified a variance in rider revenue used in our model. The rider revenue in our cost of service was inadvertently based off an old capital structure, which resulted in understatement of revenue. This change will decrease the overall deficiency and is reflected in our interim rate revenue deficiency in our Interim Rate Petition, Schedule B, Part 3 of 3, page 1. Our cost of service will be corrected in Rebuttal for final rates.

29) TCR Capital and O&M

Q. PLEASE DESCRIBE THE REBUTTAL ADJUSTMENT RELATED TO TCR CAPITAL AND O&M.

A. After the cost of service was completed, we discovered that certain AGIS capital and O&M line items were inadvertently left in the cost of service rather than removed as part of our rider removal process. Since we are proposing to recover costs related to AGIS investments in the TCR Rider, an adjustment is needed. This change will reduce the overall deficiency and is reflected in our interim rate revenue deficiency in our Interim Rate Petition, Schedule B, Part 3 of 3, page 1. Our cost of service will be corrected in Rebuttal for final rates.

VIII. COSTS RECOVERED IN RIDERS

Q. WHAT TOPICS DO YOU DISCUSS IN THIS SECTION OF YOUR TESTIMONY?

A. In this section, I present our proposed treatment of costs recovered in riders during the MYRP period, including riders that we propose to continue to use and costs we propose to move to base rates. I provide detailed information supporting the adjustments to the MYRP Forecast that I presented in Section VII of my testimony.

Q. WHAT RIDER MECHANISMS ARE CURRENTLY USED BY THE COMPANY?

A. The Company currently uses six cost recovery riders:

- Renewable Energy Standards (RES) Rider;
- Transmission Cost Recovery (TCR) Rider;
- Renewable Development Fund (RDF) Rider;
- Conservation Improvement Program (CIP) Rider;
- Windsource Rider;
- Renewable Connect Rider; and
- Fuel Clause Adjustment Rider (FCA).

Q. WHAT IS THE COMPANY PROPOSING WITH RESPECT TO THE TREATMENT OF COSTS RECOVERED THOUGH RATE RIDERS?

A. As discussed in greater detail below, we propose to:

- Continue use of the RES Rider for recovery of costs for the Freeborn and Dakota Range Wind Farms and the associated PTCs, the PTC true-up for other Company-owned wind projects, and sharing with customers potential proceeds related to any RECs the Company may sell in the future after the implementation of final rates in this case. All current and proposed rider projects and revenue credits will be collected through the RES Rider during the interim rate period.

- Continue use of the TCR Rider, with costs for ADMS, AMI, FAN, LoadSeer, TOU Pilot and Huntley Wilmarth, and MISO RECB Schedule 26 and 26A net revenues to continue to be included in the rider after implementation of final rates in this case. All current and proposed rider projects and revenue credits will be collected through the TCR Rider during the interim rate period.
- Continue use of the RDF Rider, CIP Rider, Windsource Rider, Renewable Connect Rider, and the FCA in their current forms.

In the following subsections of my testimony, I will address our proposed rate case treatment for each of these riders in detail and discuss how the Company ensures there is no double recovery of these costs.

Q. WHAT IS THE COMPANY'S BASE RATE REVENUE REQUIREMENT EXCLUSIVE OF RIDER ROLL-INS?

A. Our proposed total revenue requirement in 2021, 2022, and 2023, including our proposed increase in base rates, is approximately $2.5 billion in 2021, $2.6 billion in 2022 and $2.7 billion in 2023, as shown in Table 12 below.

Table 12

Total Cost Recovery Including Riders

Recovery Method	2021 Test Year	2022 Plan Year	2023 Plan Year
	$ in Thousands		
Present Revenues	$3,064,643	$3,053,834	$3,031,362
Cumulative Rate Increase	405,752	504,284	597,356
Proposed Revenues	3,470,395	3,558,118	3,628,718
Less: Rider Revenue included in present revenue			
TCR Rider	85,548	83,365	81,269
CIP Rider	43,570	43,136	43,604
FCA Rider	749,743	749,743	749,743
RDF Rider	37,458	33,994	33,986
RES Rider	64,742	53,387	42,977
Total Rider Revenue included in present revenue	981,062	963,625	951,580
Net Base Rate Revenue Requirement	**2,489,333**	**2,594,493**	**2,677,138**

Rate rider recovery estimates are preliminary, are subject to change, and are also subject to the Commission's decision in individual rate rider dockets. We provide this information so that the Commission, parties, and our customers can understand the combined impact of our requests.

A. RES Rider

Q. WHAT IS THE RES RIDER?

A. The RES Rider is authorized by Minn. Stat. § 216B.1645, subd. 2a for the recovery of a utility's investments, expenses, or costs associated with facilities constructed, owned, or operated by a utility to satisfy the Minnesota Renewable Energy Standard.

Q. WHAT COSTS ARE CURRENTLY INCLUDED IN THE RES RIDER?

A. The Commission's Order in Docket No. E002/M-17-818 approved our 2017 and 2018 RES Rider request to recover the costs of the following projects in the RES Rider:

- Courtenay Wind Farm;
- Foxtail Wind Farm;
- Blazing Star I Wind Farm;
- Lake Benton Wind Farm;
- Blazing Star II Wind Farm;
- Freeborn Wind Farm;
- Crowned Ridge Wind Farm;
- PTCs for all wind farms above;
- PTC true up for wind farms included in base; and
- REC sales proceeds.

Q. WHAT IS THE COMPANY'S PROPOSAL WITH RESPECT TO THE RES RIDER DURING THE MULTI-YEAR RATE PLAN?

A. As described earlier, we propose to:

- Move Courtenay Wind Farm, Foxtail Wind Farm, Blazing Star I Wind Farm, Lake Benton Wind Farm, Blazing Star II Wind Farm, Crowned Ridge Wind Farm, Jeffers Wind Farm, Community Wind North and Mower Wind Farm projects from RES Rider recovery to base rate recovery coincident with implementation of final rates in this rate case;
- Continue including costs and PTCs of the Freeborn Wind Farm in the RES Rider;

- Begin recovery of costs and PTCs on Dakota Range Wind Farm in the RES Rider;
- In the RES Rider, true-up actual PTCs related to energy production at Borders Wind Farm, Nobles Wind Farm, Pleasant Valley Wind Farm, Courtenay Wind Farm, Foxtail Wind Farm, Blazing Star I Wind Farm, Lake Benton Wind Farm, Blazing Star II Wind Farm, Crowned Ridge Wind Farm, Jeffers Wind Farm, Community Wind North and Mower Wind Farm compared to the amount included in base rates; and
- Include in the RES Rider customers' share of potential proceeds related to any RECs the Company may sell in the future.

These costs are fully supported in our 2019 and 2020 RES Rider petition filed in Docket No. E002/M-19-732, which is pending Commission review and approval.

Q. PLEASE BRIEFLY DESCRIBE THE COMPANY'S REQUEST FOR RECOVERY OF THE WIND PROJECTS GOING INTO SERVICE IN 2021 AND BEYOND IN THE RES RIDER.

A. As described by Mr. Chamberlain, the Company proposes to recover all wind farms going into service in 2021 and beyond through the RES Rider. We propose to recover the capital-related revenue requirements and property taxes, as well as incremental operating and maintenance expenses. We also propose to include all of the PTCs associated with these projects in the RES Rider. Therefore, we have not included any PTCs for these projects in the 2021-2023 MYRP as a part of our 2021-2023 MYRP.

Q. HOW IS THE RES RIDER TREATED WITH RESPECT TO PTCS IN THE 2021-2023 MYRP?

A. The Company requests PTC treatment consistent with the previously approved process. Specifically, we request that:

1) A new baseline PTC will be set in this rate case. We have included PTC amounts shown in Table 7 above as the base amount in the 2021-2023 MYRP. See Schedule 18, Production Tax Credits. These PTCs are generated from the Nobles, Pleasant Valley, Border, Courtenay, Foxtail, Blazing Star I, Lake Benton Wind, Blazing Star II Wind, Crowned Ridge Wind, Jeffers Wind, Community Wind North and Mower Wind facilities which are included in the 2021-2023 MYRP.
2) The difference between actual and baseline PTCs be recorded in the RES Tracker account.
3) The difference will be either refunded to, or recovered from, customers as established in future RES Rider filings.

Because we propose that the true-up between the level of PTCs included in base rates through this MYRP and the actual amount of PTCs earned in the respective period would occur through the RES Rider, we do not anticipate a need to address this issue in the base rate revenue requirement in the final compliance filing.

Q. WHAT ADJUSTMENT HAVE YOU MADE TO ENSURE NO DOUBLE RECOVERY OF COSTS RECOVERED IN THE RES RIDER AFTER THE IMPLEMENTATION OF FINAL RATES IN THIS CASE?

A. The project costs and revenues remaining in the RES Rider have been removed from our 2021-2023 MYRP. A review is also done for each RES filing to ensure that no costs included in base rates are included in the RES filing. I provide information related to the 2021-2023 MYRP adjustment that ensures no double recovery of these costs in Section VII.D. Rider Removals, RES Rider (adjustment 18).

B. TCR Rider

Q. WHAT IS THE TCR RIDER?

A. The TCR Rider is authorized by Minn. Stat. § 216B.16, subd. 7b to allow the recovery of Minnesota jurisdictional costs related to transmission and grid modernization investments and for MISO charges incurred for projects for which MISO assigns regional costs under Schedule 26 and Schedule 26A of its Tariff.

Q. WHAT COSTS ARE CURRENTLY INCLUDED IN THE TCR RIDER?

A. The Commission's Orders in Docket No. E002/M-17-797 approved our 2017 and 2018 TCR Rider request to recover the following projects in the TCR Rider, and provisionally approved 2019 and 2020 TCR Rider requests in Docket No. E002/M-19-721:

- ADMS;
- CapX2020 Brookings;
- CapX2020 Fargo;

- CapX2020 La Crosse;
- Big Stone – Brookings;
- La Crosse – Madison; and
- MISO RECB Schedule 26 and 26A net revenue.

Q. WHAT IS THE COMPANY'S PROPOSAL WITH RESPECT TO THE TCR RIDER DURING THE MULTI-YEAR RATE PLAN?

A. As described earlier, we propose to:

- Move the three CapX2020 La Crosse projects, CapX2020 Brookings, CapX2020 Fargo, Big Stone–Brookings, and La Crosse-Madison projects from TCR Rider recovery to base rate recovery coincident with implementation of final rates in this rate case;
- Continue recovery of the ADMS project in the TCR Rider;
- Continue recovery of the Huntley–Wilmarth project in the TCR Rider. This request was included in our 2019 and 2020 TCR Rider filing in Docket No. E002/M-19-721, and provisionally approved by Commission Order on February 21, 2020;
- Seek recovery of the AMI, FAN and LoadSeer projects in the TCR Rider;
- Seek recovery of the TOU Pilot in the TCR Rider; and
- Continue recovery of MISO RECB Schedule 26 and 26A net revenue in the TCR Rider.

Q. PLEASE DESCRIBE THE PROJECTS THAT WILL REMAIN IN THE TCR RIDER AFTER THE IMPLEMENTATION OF FINAL RATES.

A. The Company is requesting continued recovery of the ADMS and Huntley-Wilmarth projects; and to begin recovery of the AMI, FAN, LoadSeer and TOU Pilot projects, through the TCR Rider. We propose to recover these projects through the TCR Rider because these are large qualifying projects that are not yet fully in-service. We are also requesting to continue recovery of the MISO RECB Schedule 26 and 26A net revenues through the TCR Rider.

Q. WHAT ADJUSTMENT HAVE YOU MADE TO ENSURE NO DOUBLE RECOVERY OF PROJECTS CONTINUING RECOVERY IN THE TCR RIDER AFTER THE IMPLEMENTATION OF FINAL RATES IN THIS CASE?

A. The project costs and revenues remaining in the TCR Rider have been removed from our 2021-2023 MYRP. A review is also done for each TCR filing to ensure that no costs included in base, are included in the TCR filing. I provide information related to the 2021-2023 MYRP adjustment that ensures no double recovery of these costs in Section VII.D. Rider Removals, TCR Rider (adjustment 19).

C. TCR and RES Rider Roll-In

Q. PLEASE DESCRIBE HOW YOU ARE PROPOSING TO MOVE PROJECTS TO BASE RATES AT THE CONCLUSION OF THIS RATE CASE.

A. As noted above, we propose to move projects from the TCR and RES riders to base rates at the conclusion of this case because it reduces the Interim Rate increase and clarifies that there is no potential for double recovery of costs. Coincident with the implementation of final rates in this rate case, the project costs will be removed from the TCR and RES Riders for the remaining months of the year and final rates will be designed to recover the costs of these projects. This approach is consistent with the method used in Docket No. E002/GR-10-971, where we moved the Metropolitan Emission Reduction Project (MERP) costs recovered through the Environmental Improvement Rider (EIR) and the Nobles Wind, Grand Meadow Wind, and Wind2Battery projects recovered through the RES Rider into base rates when final rates were implemented in that case.

More specifically, the TCR and RES riders will be updated to exclude costs for these projects from the TCR and RES Riders for the remaining months of the year following implementation. The TCR and RES present revenues will be excluded from the 2022 plan year and final rates will be designed to recover the final revenue requirement approved by the Commission, including the final revenue requirement for these projects. The interim rate refund will not be affected for these projects, as any over/under recovery during the Interim Rate period related to these projects will remain in the TCR or RES Rider.

Q. WHAT DOES THE COMPANY PROPOSE TO INCLUDE IN ITS FINAL RATE COMPLIANCE TO SUPPORT MOVEMENT OF THESE PROJECTS FROM THE TCR RIDER TO BASE RATES?

A. We propose to submit TCR and RES Rider compliance reports with final rate compliance reporting. These reports will clearly identify the revenue requirements removed from the TCR and RES Riders, the revenue recovered from customers for the projects moving to base rates during the Interim Rate period, and the development of the revised TCR and RES Rider adjustment factors. The Company anticipates this process will be similar to the process used to move recovery of CIP costs from the CIP Rider to base rates.

Q. HOW ARE THE PROJECTS THAT WILL MOVE TO BASE RATES TREATED DURING THE INTERIM RATE PERIOD?

A. During the interim rate period, the Company proposes that the identified projects continue recovery through the TCR or RES Riders, along with the other costs that we are proposing to continue to recover through the TCR and RES Riders after implementation of final rates.

Q. IF YOU ARE PROPOSING TO INCLUDE THE PROJECTS IN THE TCR AND RES RIDERS DURING THE INTERIM RATE PERIOD, HOW WILL YOU ENSURE NO DOUBLE RECOVERY OF THESE PROJECT COSTS OCCURS DURING THIS TIME?

A. Because we are proposing to continue recovery of these projects through the TCR and RES Riders during the interim period and to move these projects into base rates at the end of this case. The 2021 test year also includes the project costs in the test year cost of service as well as the project revenues in present revenue. Thus, an interim rate adjustment is necessary to ensure no double recovery of these costs during the interim rate period. Accordingly, our 2021 and 2022 Interim Rate requests each include an adjustment to remove the projects identified to roll into base rates and the present revenue from the development of Interim Rates.

Q. PLEASE PROVIDE ADDITIONAL DETAIL RELATED TO THE INTERIM RATE ADJUSTMENT FOR THE TCR AND RES RIDER COSTS.

A. The Interim Rate Adjustment removes the project costs and present revenue included in the 2021 test year and 2022 plan year from the Interim Cost of Service. This adjustment decreases the Interim Cost of Service rate base and present revenue by the amounts shown in Table 13 below.

Table 13

Rider Removals from Interim Rates ($ in millions)

	Decrease in Rate Base		**Decrease in Present Revenue**	
	2021	2022	2021	2022
TCR Rider	$574.3	$551.4	$85.5	$83.4
RES Rider	1,138.6	1,020.8	64.7	53.4
TOTAL Rider Removal	$1,712.9	$1,572.2	$150.2	$136.8

Additional detail on these adjustments can be found in Volume 1, Notice of Change in Rates and Interim Rate Petition, Interim Rate Supporting Schedules and Workpapers.

Q. DO YOU PROVIDE ANY OTHER INFORMATION RELATED TO TREATMENT OF TCR AND RES RIDER COSTS AND PROJECTS DURING THE MULTI-YEAR RATE PLAN PERIOD?

A. Yes. Exhibit___(BCH-1), Schedule 22, Rider Roll-in Timeline, provides a timeline illustrating how projects will be rolled into base rates or will remain in the TCR and RES Riders during the course of the multi-year rate plan.

D. RDF Rider

Q. WHAT COSTS ARE RECOVERED THROUGH THE RDF RIDER?

A. Commission-approved RDF costs pursuant to Minn. Stat. §§ 116C.779 and 216B.1645, subd. 2 are recovered from retail customers through the RDF Rider.

Q. HOW IS THE RDF RIDER TREATED IN THE MYRP FORECAST?

A. Both revenue and amortization expense for the RDF Rider are included in the MYRP Forecast. The amount of each is equal and; therefore, does not contribute to the MYRP Forecast deficiency. Any true-up of the revenues and costs will occur in the RDF Rider, such that there will be no need to address a change in revenue requirement in the final compliance filing.

E. CIP Rider

Q. WHAT COSTS ARE RECOVERED THROUGH THE CIP RIDER?

A. The CIP Rider is designed to recover conservation and demand-side management program costs that are incremental to the level collected in base rates. Base electric rates are designed to include conservation and demand-side management cost at an authorized level approved by the Deputy Commissioner of the Minnesota Department of Commerce, Division of Energy Resources for a given test year. The CIP Rider collects any incremental conservation and demand-side management costs above the authorized level in final base rates.

Q. HOW IS THE CIP RIDER TREATED IN THE MYRP FORECAST?

A. As discussed in Section VII, Annual Adjustments to the MYRP, the CIP Rider amount in the case is at the level needed to assure that the CIP revenue (Base and Rider) is equal to the expense in the MYRP Forecast. With the total amount of CIP expense and CIP revenue equal, the overall CIP program does not contribute to the test year deficiency.

F. Windsource Rider

Q. WHAT COSTS ARE RECOVERED THROUGH THE WINDSOURCE RIDER?

A. Costs related to the Windsource program, a stand-alone retail service program with discrete revenues, purchase power contracts and operating expenses, are recovered through the Windsource Rider.

Q. HOW IS THE WINDSOURCE RIDER TREATED IN THE MYRP FORECAST?

A. All revenue and expense related to the Windsource program is excluded from the MYRP Forecast. The Windsource rider removal adjustment shown in column 26 of Schedules 11a-11c, 2021-2023 Income Statement Adjustment Schedules reflects the removal of the Windsource related expenses and revenue included in base data and does not impact the deficiency. Any true up of the revenues and costs incurred during the MYRP Forecast will occur in the Windsource Rider and; therefore, there will be no need to address a change in revenue requirement in the final compliance filing.

Q. IS THE COMPANY ANTICIPATING ANY CHANGE IN THE WINDSOURCE RIDER DURING THE MYRP?

A. Yes. The Company anticipates transitioning Windsource customers to Renewable*Connect over a period of time in 2021 and 2022. All transactions associated with the transition will occur within the respective mechanism and there is no impact to the COSS. Further information is provided in Section VII, Annual Adjustments to the MYRP.

G. Renewable*Connect Rider

Q. WHAT COSTS ARE RECOVERED THROUGH THE RENEWABLE*CONNECT RIDER?

A. Costs related to the Renewable*Connect program, a stand-alone retail service program with discrete revenues, purchase power contracts and operating expenses, are recovered through the Renewable*Connect Rider.

Q. HOW IS THE RENEWABLE*CONNECT RIDER TREATED IN THE MYRP FORECAST?

A. All revenue and expense related to the Renewable*Connect program is excluded from the MYRP Forecast. The Renewable*Connect Rider removal adjustment shown in column 23 of Schedules 11a-11c, 2021-2023 Income Statement Adjustment Schedule reflects the removal of the Renewable*Connect-related expenses and revenue included in base data and does not impact the deficiency. Any true-up of the revenues and costs incurred during the MYRP Forecast will occur in the Renewable*Connect Rider, such that there will be no need to address a change in revenue requirement in the final compliance filing. Further information is provided in Section VII, Annual Adjustments to the MYRP.

H. Fuel Clause Adjustment

Q. WHAT COSTS ARE RECOVERED THROUGH THE FCA?

A. Fuel and purchased energy are recovered from customers through the FCA.

Q. HOW IS THE FCA TREATED IN THE MYRP FORECAST?

A. Both revenue and fuel expenses recovered through the FCA are included in the MYRP Forecast, and the total amount of each is equal. Any true-up of the revenues and costs during the MYRP Forecast will occur in the FCA and;

therefore, there will be no need to address a change in revenue requirement in the final compliance filing. I provide a reconciliation of fuel costs and revenues in the Cost of Service in Schedule 21, Fuel Reconciliation. As required by the Commission in its November 5, 2019 Order Approving Compliance Filings in Docket No. E999/CI-03-802, this schedule illustrates that fuel revenues are equal to fuel costs to be recovered through the FCA and thus the Company's proposed base rates do not include any amount of FCA costs.

I. Electric Vehicle Program Tracker

Q. PLEASE DESCRIBE THE STATUS OF THE ELECTRIC VEHICLE TRACKER AND DEFERRAL.

A. In its June 22, 2015 Order in Docket No. E002/M-15-111, the Commission approved the Company's use of a tracker account to defer costs associated with electric vehicle (EV) rate education and outreach activities. Consistent with Minn. Stat. § 216B.1614, subd. 2(a)(2), the Company attributes costs to the tracker associated with providing general EV information, as well as EV rate-specific information. Additionally, in granting approval for several EV pilots in its July 17, 2019 Order in Docket No. E002/M-18-643, the Commission approved deferred accounting for Xcel Energy's O&M. This deferred accounting applied to expenses incurred between the date of the Commission's Order (July 17, 2019) and January 1, 2020.

Q. WHAT IS THE COMPANY'S PROPOSED TREATMENT OF EV PILOT COSTS DURING THE MYRP?

A. The Company proposes to include in base rates the capital and O&M expenses for 2021 to 2023 associated with Commission-approved EV pilots and programs, as well as new offerings for which the Company intends to seek approval during the MYRP period. These EV pilots and programs and the associated budgets are discussed in Ms. Bloch's Direct Testimony.

The Company is also proposing to incorporate the balance in the EV tracker established in Docket No. E002/M-15-111 and the final deferral balance related to Docket No. E002/18-643 into a three-year amortization over the MYRP period. This will ensure that all costs for prior years that have been approved for tracking and deferral will be reviewed and included in base rates. We propose to include all EV tracker costs through December 31, 2020. The total amount of these costs will be known at the time of Rebuttal Testimony (which is anticipated to be due after the conclusion of calendar year 2020) and will, therefore be updated at that time.

Finally, as Ms. Bloch discusses, certain O&M costs that are unknown at this time and incremental to the MYRP budget will continue to be included in our established EV cost tracker. Use of the EV tracker is consistent with prior Commission approvals in our separate EV program and pilot dockets and will be addressed in proceedings proposing any new offerings.

IX. COMPLIANCE WITH PRIOR COMMISSION ORDERS

Q. WHAT TOPIC DO YOU DISCUSS IN THIS SECTION OF YOUR TESTIMONY?

A. The Completeness Checklist included in the Direct Testimony of Mr. Chamberlain as Exhibit___(GPC-1), Schedule 2 documents how our rate case filing includes information required by Rule or prior Commission Orders, and provides specific references to the testimony of Company witnesses that addresses each requirement. In this section of my testimony, I identify and provide information related to specific requirements from prior Commission Orders that have not been addressed elsewhere in my testimony.

A. General Rate Case – Docket No. E002/GR-12-961

1) Mapping to FERC Form 1

Q. PLEASE DESCRIBE THE COMPANY'S COMPLIANCE WITH REQUIREMENTS TO RECONCILE INFORMATION BETWEEN THE COMPANY'S FERC FORM 1 AND GENERAL LEDGER.

A. Order Point 47 from the Commission's September 3, 2013 order in Docket E002/GR-12-961 (the 12-961 Order) stated:

> Expanding upon the information filed under Minnesota Rules 7825.4000(B) and 7825.4100(B), direct the Company to include in its initial filing of its next rate case balance sheet and income statement reconciliations between its FERC Form 1 and its general ledger accounts for each of the three most recent calendar years relative to the rate case test year. The schedules provided should be produced in like manner as requested and illustrated in the Department's Information Request 128-Revised, marked in the record as Exhibit 163, DOC Attachment ACB-15.

These requirements have been met. The mapping to FERC Form 1 is located in Volume 3, Required Information, Section IV, Other Required Information, Tab 5, GAAP/FERC/COSS Comparison. There we provide accounting of the NSPM Total Company for 2017 to 2019. For each year, we provide the GAAP financial statements reconciled to the FERC Form 1. We then provide the FERC Form 1 reconciled to the Minnesota Jurisdictional Annual Report Total Company amounts.

2) Changes Between Actuals and MYRP Forecast

Q. PLEASE DESCRIBE THE COMPANY'S COMPLIANCE WITH REPORTING REQUIREMENTS RELATED TO DEVIATIONS BETWEEN MOST RECENT ACTUALS AND THE MYRP FORECAST.

A. Order Point 47 of the 12-961 Order also requires explanations for deviations ten percent or greater (+/- 10 percent) "between actuals and [the Company's] test-year request." Explanations of operating expense variations of +/-5 percent and +/-$500,000 are provided for 2019 actuals compared to the 2021 budget by FERC account in Volume 6, Budget Documentation, Variance Analysis. Explanations of variations of +/-10 percent on rate base items are provided with the schedules in Volume 3, Required Information, Section IV, Other Required Information, Tab 5, GAAP/FERC/COSS Comparison.

3) Financial Labeling

Q. WHAT ARE THE REQUIREMENTS RELATED TO LABELING FINANCIAL INFORMATION?

A. In the Revenue Requirement Rebuttal Testimony in Docket E002/GR-12-961, the Company agreed to make efforts to label all costs and revenues to the relevant financial source: Xcel Energy Services, Inc.; NSP System; NSP-Minnesota or NSPM (Total Company – electric and gas utilities); NSPM Electric; and State of Minnesota Electric Jurisdiction.

Q. HOW HAS THE COMPANY COMPLIED WITH THIS COMMITMENT?

A. We have made a good faith effort to satisfy this commitment throughout all testimony in this case. For reference, following is a list of the labels used and the definitions of each.

- Xcel Energy or XEI: The entire enterprise – XES, NSPM, NSPW, SPS, PSCo, and affiliate companies.
- XES: Xcel Energy Services: Xcel Energy's service company that provides services across all Xcel Energy affiliate companies.
- NSPM (Total Company): Northern States Power Company-Minnesota, providing service to electric and gas customers in Minnesota, North Dakota, and South Dakota.
- NSPW (Total Company): Northern States Power Company-Wisconsin, providing service to electric and gas customers in Wisconsin and Michigan.
- NSP System: The combined NSPM and NSPW electric production and transmission system.
- NSPM Electric: Northern States Power Company, including the portion allocated or direct assigned to the electric utility.
- State of Minnesota: Items physically located in the State of Minnesota such as distribution facilities or property taxes assessed by the State.
- State of Minnesota Electric Jurisdiction: Amounts direct assigned or allocated to the electric utility and to the State of Minnesota. Interchange Agreement billings to and from NSPW are reflected in revenues and expenses, respectively.
- State of Minnesota Electric Jurisdiction net of Interchange Agreement billings to NSPW or State of Minnesota Electric Jurisdiction, net of Interchange: The net amount allocated to the cost of service for electric customers in the State of Minnesota. The portion of the item billed to NSPW through the Interchange Agreement has been netted against the item to show the net impact to Minnesota electric customers.

Further, other Company witnesses provide amounts in their testimonies from several applicable financial sources. To the extent practicable, they have also provided the State of Minnesota jurisdictional amount. The jurisdictional amounts were developed under my guidance and are consistent with development of allocators as explained in the CAAM presented by Mr. Baumgarten as Exhibit ___ (RLS-1), Schedule 3 to his Direct Testimony, and in Exhibit ___ (BCH-1), Schedule 3, Cost of Service Study Summary, to my Direct Testimony. In order to provide further context, an index to these financial sources is included as Exhibit___(BCH-1), Schedule 5, Labeling of Financial Sources.

4) Wholesale Customer Study

Q. WHAT REQUIREMENT RELATED TO WHOLESALE CUSTOMERS DO YOU ADDRESS?

A. With respect to the costs and revenues related to services provided to wholesale customers, the Company and Department agreed as follows:

> The Company will provide as a compliance filing in future rate cases a wholesale customer study which shows all wholesale customers being served by the Company (including, but not limited to, full requirements, partial requirements, and market based wholesale customers), types of service being provided to each wholesale customer, costs and revenues associated with each wholesale customer, and a clear showing either that wholesale costs are allocated out of the retail rate case or that the revenues are included in the retail rate case, for all services provided to wholesale customers.[8]

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[8] May 22, 2013 Issues List Page 19 in Docket No E002/GR-12-961.

Q. HOW HAS THE COMPANY COMPLIED WITH THIS REQUIREMENT?

A. Schedule 14, Wholesale Customer Study, provides the required information. The study does not address wholesale transmission revenues. Wholesale transmission revenues and associated costs are discussed in the Direct Testimony of Mr. Benson.

B. Decommissioning

Q. PLEASE DESCRIBE THE COMPANY'S COMPLIANCE WITH REQUIREMENTS RELATED TO NUCLEAR DECOMMISSIONING.

A. A discussion of the Company's compliance history and the status of pending dockets with respect to nuclear decommissioning and the use of Department of Energy payments is contained in Section VII. Triennial Nuclear Decommissioning Costs, of Mr. Moeller's Direct Testimony.

C. Other Compliance Requirements

1) Incentive Compensation Refunds

Q. WHAT ARE THE REQUIREMENTS RELATED TO INCENTIVE COMPENSATION REFUNDS?

A. In Docket No. E002/GR-10-971, the Commission required Xcel Energy to continue to refund all incentive compensation payments earned according to the Xcel Energy incentive compensation plan and recoverable in rates under the Order, but not paid.

Q. HOW IS COMPLIANCE WITH THESE REQUIREMENTS REFLECTED IN THE COMPANY'S RATE CASE REQUEST?

A. For 2019 (paid in March 2020), incentive plan payouts were at a level that required the Company to refund customers $2.2 million, as reported in our annual incentive compensation compliance filing in Docket Nos. E002/GR-92-1185, G002/GR-92-1186, and E,G002/M-20-516 on June 1, 2020. Our 2016-2019 MYRP, which was based on a 2016 test year and escalated to a 2019 plan year, included the budgeted incentive compensation costs accrued in 2019 and payable in March 2020, after excluding certain costs (*e.g.*, executive long-term incentive).

The 2021 test year includes the budgeted incentive compensation costs accrued in 2021 and payable in March 2022, after excluding certain costs (*e.g.*, certain LTI, which I identified in Section VII.B.5, Annual Adjustments to the MYRP).

Q. DOES THE COMPANY PROPOSE ANY CHANGES TO THE AIP INCENTIVE REFUND PROGRAM?

A. Yes. Once rates have been established at the conclusion of this rate proceeding, we propose to eliminate the yearly AIP compliance filing requirement and any associated reports regarding the AIP. The Company is also proposing the elimination of the AIP refund. Company witness Ms. Lowenthal discusses this proposal in her Direct Testimony.

2) Non-Asset Based Trading Activities–Fully Allocated Cost Study and Incremental Cost Study

Q. PLEASE DESCRIBE THE COMPANY'S COMPLIANCE WITH COST ALLOCATION REQUIREMENTS FOR NON-ASSET BASED TRADING.

A. In Docket No. E002/GR-10-971, the Company was directed to file in its next rate case both an incremental and fully allocated cost study of its non-asset based trading activities. In Direct Testimony in Docket E002/GR-15-826, we requested that only a fully allocated cost study be submitted in future rate cases, as the incremental study is not used to determine the level of costs to charge to this activity. No opposition was raised in those proceedings. Therefore, only the fully allocated cost study is provided with this testimony as Schedule 17, Non-Asset Based Trading Cost Study.

3) Nuclear Fuel Outage Costs

Q. PLEASE DESCRIBE THE COMPANY'S COMPLIANCE WITH REPORTING REQUIREMENTS FOR NUCLEAR FUEL OUTAGE COSTS.

A. In Docket No. E002/GR-08-1065, the Company was directed to include an analysis of nuclear plant outage costs as shown in Exhibit 86 to the hearing record. The required information is included in Volume 4, Section VIII Rate Base (Plant), Tab P4-1, Nuclear Outage Amortization. Volume 4 also includes schedules in support of the 2022 and 2023 Plan Year nuclear fuel outage costs. These schedules provide a determination of the Minnesota retail jurisdiction revenue requirements associated with the Nuclear Outage Deferral and Amortization method, as well as a comparison to the Direct Expense method for the MYRP Forecast.

4) Capacity Cost Report

Q. PLEASE DESCRIBE THE COMPANY'S COMPLIANCE WITH REQUIREMENTS RELATED TO CAPACITY COSTS.

A. In Docket No. E002/GR-08-1065, the Commission ordered the Company to describe NSP System short-term and long-term capacity costs by contract. The required information is attached as Exhibit___(BCH-1) Schedule 15, Capacity Cost Study, which is Trade Secret. The methodology for budgeting capacity costs for the 2021-2023 MYRP is similar to that described by Mr. David G. Horneck in his Direct Testimony from Docket No. E002/GR-10-971. Contracts with which NSPM has long-term obligations to purchase capacity remain the same as described in that docket. The Company anticipates that it can meet the expected MISO capacity planning reserve requirements for the 2021 planning year from its current generation and long term purchased capacity contracts. Therefore, the Company does not expect to purchase short term capacity contracts for the 2021 test year.

5) Lobbyist Compensation

Q. PLEASE DESCRIBE THE COMPANY'S COMPLIANCE WITH REPORTING REQUIREMENTS RELATED TO LOBBYIST COMPENSATION.

A. In Docket No. E002/GR-10-971, we agreed to include a report of the total compensation for employees engaged in lobbying with an explanation of the costs included and excluded in the rate request. This information is provided in the Direct Testimony of Mr. Husen.

6) North Dakota Investment Tax Credits

Q. WHAT ARE THE REQUIREMENTS RELATED TO THE NORTH DAKOTA INVESTMENT TAX CREDITS?

A. In Docket No. E-002/M-15-805, the Company was instructed to share non-Minnesota state tax credits as follows:

> Northern States Power Company d/b/a Xcel Energy shall credit its Minnesota ratepayers for their proportionate share of used North Dakota Investment Tax Credits associated with the Courtenay Wind project, based on the pro-rata share of the costs of the Courtenay Wind project that is charged to Minnesota ratepayers.

Q. HOW HAS THE COMPANY COMPLIED WITH THESE REQUIREMENTS?

A. The North Dakota state credit for North Dakota-located wind generation is the only non-Minnesota state credit utilized by NSPM. Due to the size of the credits available relative to the North Dakota state taxable income, it is anticipated that the utilization of these credits will be limited by taxable income and not specifically known until North Dakota state tax returns are filed. The potential for credits are primarily the result of the Border, Courtenay, and Foxtail Wind Farms. Pursuant to the Commission's April 11, 2017 Order in Docket No. E002/M-17-818, we will include North Dakota investment tax credits (NDITCs) associated with the wind farms mentioned above in our calculation of the revenue requirements in the RES rider.

7) Capital True-Up

Q. PLEASE DESCRIBE THE COMPANY'S COMPLIANCE WITH CAPITAL TRUE-UP REPORTING REQUIREMENTS.

A. Continuing the capital true-up reporting from our 2016-2019 MYRP in accordance with the Commission's March 13, 2020 Order in Docket No. E002/M-19-688, the Company will submit an annual compliance filing in May 2021 for calendar year 2020. This compliance filing will compare the actual capital-related revenue requirements (actuals) to the capital forecast revenue requirements (forecast). The Company has also proposed to continue the capital true-up, as discussed by Company witness Mr. Chamberlain.

8) BIS Rider

Q. DOES THE MYRP INCLUDE RECOVERY FOR THE DISCOUNTS PROVIDED UNDER THE TEMPORARY DISCOUNT PROGRAMS IN THE BIS RIDER THAT ARE RELATED TO EITHER THE PANDEMIC OR CIVIL UNREST?

A. No. The temporary discount program approved in Docket No. E002/M-20-436 will continue through March 31, 2021; therefore, the Company does not know the final amount of the discounts and is not yet able to provide the cost/benefit analysis required in the Commission's Order. Additionally, the second temporary discount program filed in August 2020 in Docket No. E002/M-20-662 is pending before the Commission. If available, the Company may include the information in Rebuttal Testimony, or else wait to seek recovery in the next rate case following this one. The Company will defer the discounts awarded in Account 182.3, Regulatory Assets, with the offset to costs in Account 407.4, Regulatory Credits.

9) Recurring Compliance Reporting Requirements

Q. WHAT INFORMATION DO YOU PROVIDE IN THIS SECTION?

A. Below, I provide information on compliance requirements of a recurring nature reported upon in each rate case.

a) Edison Electric Institute Spare Transformer Sharing Agreement

Q. PLEASE DESCRIBE THE COMPANY'S COMPLIANCE WITH REPORTING REQUIREMENTS ON THE SPARE TRANSFORMER SHARING AGREEMENT.

A. The Commission's Order in Docket No. E002/PA-06-1662 required the Company to report any sales or purchases of transformers made under the EEI Spare Transformer Sharing Agreement in its next rate case. Over the life of the program there have been no triggering events to initiate a transformer sale or purchase under the program. Therefore, Xcel Energy has not sold or purchased any transformers under this agreement.

b) Minnesota Emissions Allowance

Q. PLEASE DESCRIBE THE COMPANY'S USE OF APPROVED DEFERRED ACCOUNTING RELATED TO EMISSIONS ALLOWANCES.

A. In Docket No. E002/M-94-13, the Commission ordered deferred accounting for revenues from the sale of certain emission allowances until the Company's next general rate case, where the effects of then-new changes to the FERC Uniform System of Accounts could be examined. The Company has continued the deferral over several rate cases, but the accumulated unamortized deferred balance of emission sales is less than $5,000. Due to the small level in this account that has been accumulating since 2010 when the deferral was last resolved, combined with the limited market for these allowances, the Company is proposing to discontinue the deferral of emission allowances with no adjustment in this proceeding. Thus, there is no adjustment included in this filing.

c) Advantage Service (a/k/a HomeSmart)

Q. PLEASE DESCRIBE THE COMPANY'S COMPLIANCE WITH REQUIREMENTS RELATED TO HOME SMART.

A. In Docket No. E002/GR-91-1, the Company was directed to require NSP Advantage Service (now branded as Xcel Energy HomeSmart) to: 1) pay a return on the use of the Company's billing services asset; 2) compensate the Company for its personnel's referral time; and 3) compensate the Company for use of its mailing lists. The Company has complied with these requirements.

d) Liberty Paper

Q. WHAT ARE THE REQUIREMENTS RELATED TO LIBERTY PAPER?

In Docket No. E002/M-93-1253, the Commission ordered the Company to segregate the cost of constructing a steam pipeline from Sherco to Liberty Paper, Inc. from utility rate base, and to record operating and maintenance expenses to non-utility operations.

Q. HOW HAS THE COMPANY COMPLIED WITH THESE REQUIREMENTS?

A. When the Commission approved the amended agreement with Liberty Paper, Inc., in its February 21, 2020 Order in Docket No. E002/M-19-663, the Commission included a requirement that, for the duration of steam sales to Liberty Paper, Inc., the Company must demonstrate the reasonableness of the

Company's proposed cost allocations related to the steam sales. The allocation of costs to Liberty Paper, Inc. and the reasonableness of those costs, are discussed in Section III of NSPM's CAAM, which is Schedule 3 to Mr. Baumgarten's Direct Testimony.

e) Tax Benefit Transfer Leases

Q. PLEASE DESCRIBE THE COMPANY'S COMPLIANCE WITH REQUIREMENTS RELATED TO TAX BENEFIT TRANSFER LEASES.

A. In Docket No. G002/GR-97-1606, the Company was directed to treat Tax Benefit Transfer (TBT) leases consistent with prior Commission approved methodology. There are no TBTs included in the MYRP.

f) Sale of Renewable Energy Credits

Q. PLEASE DESCRIBE THE COMPANY'S COMPLIANCE WITH REQUIREMENTS RELATED TO THE SALE OF RECS.

A. In Docket No. E002/GR-08-1065, the Company was directed to flow revenues from the sale of RECs through the RES Rider. A petition to pass certain RECs to customers using the FCA was approved by the Commission in Docket No. E002/M-12-1132. The Commission ordered the proceeds from the sale of RECs be returned to customers through the RES Rider unless the Commission makes a specific determination to allow a sharing of the proceeds. The Company has complied with this requirement.

g) Competitive Bidding

Q. PLEASE DESCRIBE THE COMPANY'S COMPLIANCE WITH REQUIREMENTS FOR ANY NON-PERFORMANCE PENALTIES RELATED TO COMPETITIVELY BID GENERATION.

A. In Docket No. E002/M-95-174 the Company was permitted to offer Company-owned generation to compete against other provider offerings. The Company is required to track capacity-related non-performance penalties on NSP Generation projects for return to customers. We have incurred no such penalties.

X. CONCLUSION

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS TO THE COMMISSION.

A. I recommend that the Commission determine an overall 2021 retail revenue requirement of $3.47 billion and 2021 revenue deficiency of $405.8 million for the Company's Minnesota jurisdictional electric operation, determined by the cost of service for the 2021 test year. I also recommend a revenue deficiency for each year of the MYRP as follows:

Table 14

2021-2023 Revenue Requests

Minnesota Jurisdictional Deficiency Net of Interchange ($s in millions)

MYRP Year	2021	2022	2023
Amount, cumulative	$405.8	$504.3	$597.4
Amount, incremental	$405.8	$98.5	$93.1
Average % increase, incremental *	13.2%	3.3%	3.2%

* The average percent increase, incremental is calculated using the annual revenue request over the forecasted present revenues in each applicable year, less prior year(s).

Lastly, I also recommend the Commission grant a 2021 interim rate increase of $308.9 million, and an additional 2022 interim rate increase of $96.4 million, for the Company's Minnesota jurisdictional operation.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Resume of Benjamin C. Halama

Manager of Revenue Analysis
Revenue Requirements–North

Xcel Energy Services Inc.
414 Nicollet Mall
Minneapolis, MN 55401

Current Responsibilities

Since September 2018, I have worked as Manager of the Revenue Requirements–North department. In this position, I prepare and present cost of service studies, revenue requirement determinations, and jurisdictional annual reports for the electric and gas operations of Northern States Power Company to the Minnesota Public Utilities Commission, the South Dakota Public Utilities Commission, and the North Dakota Public Service Commission, and the Federal Energy Regulatory Commission.

Employment History

Xcel Energy – Minneapolis, MN

- Manager of Revenue Requirements–North, September 2018 to Present
- Manager Utility Accounting, May 2015 to August 2018

Target Corporation – Minneapolis, MN

- Manager of Inventory Accounting, 2014-2015
- Lead Analyst Financial Reporting, 2013-2014
- Supervisor Sales Accounting and Operations, 2011-2013

Copeland Buhl and Company – Wayzata, MN

- Accounting Supervisor, 2007-2011
- Senior Accountant, 2004-2007
- Staff Accountant, 2002-2004

Education

University of Wisconsin at Eau Claire, May 2002
Bachelor of Science in Accounting

SUMMARY OF REVENUE REQUIREMENTS
($000's)

Line	Description	Adjusted Proposed Test Year 2021	Adjusted Proposed Plan Year 2022	Adjusted Proposed Plan Year 2023
1	Average Rate Base	$9,950,576	$10,267,755	$10,656,235
2	Operating Income (Before AFUDC)	$413,739	$369,245	$324,314
3	Allowance for Funds Used During Construction	$28,498	$25,065	$31,124
4	Total Available for Return (Line 2 + Line 3 + Rounding)	$442,237	$394,310	$355,438
5	Overall Rate of Return (Line 4 / Line 1)	4.44%	3.84%	3.34%
6	Required Rate of Return	7.35%	7.34%	7.33%
7	Operating Income Requirement (Line 1 x Line 6)	$731,367	$753,653	$781,102
8	Income Deficiency (Line 7 - Line 4)	$289,131	$359,343	$425,664
9	Gross Revenue Conversion Factor	1.40335	1.40335	1.40335
10	Revenue Deficiency (Line 8 x Line 9)	$405,752	$504,284	$597,356
11	Retail Related Revenue Under Present Rates	$3,064,643	$3,053,834	$3,031,362
12	Percentage Increase Needed in Overall Revenue (Line 10 / Line 11)	13.24%	16.51%	19.71%
13	Retail Related Revenue Under Present Rates EXCLUDING FUEL	$2,314,900	$2,304,091	$2,281,619
14	Percentage Increase Needed Excluding Fuel (Line 10 / Line 13)	17.53%	21.89%	26.18%

COST OF SERVICE SUMMARY for 2021-2023 MYRP FORECAST ($000's)

Line No.		Minnesota Electric Jurisdiction 2021 Test Year	2022 Plan Year	2023 Plan Year
1	**Composite Income Tax Rate**			
2	State Tax Rate	9.80%	9.80%	9.80%
3	Federal Statuatory Tax Rate	21.00%	21.00%	21.00%
4	Federal Effective Tax Rate	18.94%	18.94%	18.94%
5	**Composite Tax Rate**	**28.74%**	**28.74%**	**28.74%**
6	Revenue Conversion Factor (1/(1--Composite Tax Rate))	1.403351	1.403351	1.403351
7				
8	**Weighted Cost of Capital**			
9	Active Rates and Ratios Version	Proposed	Proposed	Proposed
10	Cost of Short Term Debt	1.00%	2.82%	2.21%
11	Cost of Long Term Debt	4.22%	4.19%	4.17%
12	Cost of Common Equity	10.20%	10.20%	10.20%
13	Ratio of Short Term Debt	0.54%	0.16%	0.20%
14	Ratio of Long Term Debt	46.96%	47.34%	47.30%
15	Ratio of Common Equity	52.50%	52.50%	52.50%
16	Weighted Cost of STD	0.01%		
17	Weighted Cost of LTD	1.98%	1.98%	1.97%
18	Weighted Cost of Debt	1.99%	1.98%	1.97%
19	Weighted Cost of Equity	5.36%	5.36%	5.36%
20	**Required Rate of Return**	**7.35%**	**7.34%**	**7.33%**
21				
22	**Rate Base**			
23	Plant Investment	21,390,993	22,252,272	23,066,979
24	Depreciation Reserve	9,900,637	10,566,509	11,245,231
25	Net Utility Plant	11,490,356	11,685,763	11,821,748
26	CWIP	394,160	417,943	532,577
27				
28	Accumulated Deferred Taxes	2,683,859	2,744,670	2,754,593
29	DTA - NOL Average Balance			
31	DTA - Federal Tax Credit Average Balance	(438,661)	(597,425)	(746,010)
32	Total Accum Deferred Taxes	2,245,198	2,147,245	2,008,583
33				
34	Cash Working Capital	(143,326)	(153,713)	(164,501)
35	Materials and Supplies	152,207	152,207	152,207
36	Fuel Inventory	84,026	84,026	84,026
37	Non-plant Assets and Liabilities	104,503	122,703	140,883
38	Customer Advances	(7,575)	(7,575)	(7,575)
39	Customer Deposits	(44,786)	(44,786)	(44,786)
40	Prepaids and Other	70,039	71,706	72,297
41	Regulatory Amortizations	96,171	86,726	77,943
42	Total Other Rate Base Items	311,259	311,294	310,493
43				
44	**Total Rate Base**	**9,950,576**	**10,267,755**	**10,656,235**
45				

COST OF SERVICE SUMMARY for 2021-2023 MYRP FORECAST ($000's)

Line No.		Minnesota Electric Jurisdiction		
		2021 Test Year	2022 Plan Year	2023 Plan Year
46	**Operating Revenues**			
47	Retail	3,064,187	3,053,378	3,030,907
48	Interdepartmental	456	456	456
49	Other Operating Rev - Non-Retail	545,625	563,137	568,466
50	**Total Operating Revenues**	**3,610,268**	**3,616,971**	**3,599,829**
51				
52	**Expenses**			
53	Operating Expenses:			
54	Fuel	919,984	919,838	920,319
55	Deferred Fuel			
56	Variable IA Production Fuel			
57	Purchased Energy - Windsource	0	0	0
58	Fuel & Purchased Energy Total	919,984	919,838	920,319
59	Production - Fixed	431,515	429,937	438,062
60	Production - Fixed IA Investment			
61	Production - Fixed IA O&M	42,883	43,834	55,724
62	Production - Variable	5,994	6,087	6,246
63	Production - Variable IA O&M	14,848	15,134	14,378
64	Production - Purchased Demand	140,623	143,436	143,562
65	Production Total	635,863	638,428	657,973
66	Regional Markets	9,656	9,429	9,863
67	Transmission IA	104,534	111,430	115,795
68	Transmission	142,672	147,680	150,716
69	Distribution	127,374	132,937	135,655
70	Customer Accounting	58,738	52,401	41,826
71	Customer Service & Information	128,469	128,545	128,615
72	Sales, Econ Dvlp & Other	282	284	283
73	Administrative & General	225,387	235,276	238,616
74	**Total Operating Expenses**	**2,352,958**	**2,376,248**	**2,399,661**
75				
76	Depreciation	737,364	778,372	792,829
77	Amortization	55,040	51,576	49,467
78				
79	**Taxes:**			
80	Property Taxes	191,930	201,387	213,848
81	ITC Amortization	(1,223)	(1,222)	(1,218)
82	Deferred Taxes	72,595	16,116	(10,407)
83	Deferred Taxes - NOL			
84	Less State Tax Credits deferred			
85	Less Federal Tax Credits deferred	(155,847)	(161,680)	(135,490)
86	Deferred Income Tax & ITC	(84,474)	(146,787)	(147,115)
87	Payroll & Other Taxes	27,815	28,067	28,308
88	**Total Taxes Other Than Income**	**135,271**	**82,667**	**95,041**
89				

COST OF SERVICE SUMMARY for 2021-2023 MYRP FORECAST ($000's)

Line No.		Minnesota Electric Jurisdiction 2021 Test Year	2022 Plan Year	2023 Plan Year
90	**Income Before Taxes**			
91	Total Operating Revenues	3,610,268	3,616,971	3,599,829
92	less: Total Operating Expenses	2,352,958	2,376,248	2,399,661
93	Book Depreciation	737,364	778,372	792,829
94	Amortization	55,040	51,576	49,467
95	Taxes Other than Income	135,271	82,667	95,041
96	**Total Before Tax Book Income**	329,635	328,108	262,831
97				
98	**Tax Additions**			
99	Book Depreciation	737,364	778,372	792,829
100	Deferred Income Taxes and ITC	(84,474)	(146,787)	(147,115)
101	Nuclear Fuel Burn (ex. D&D)	99,007	104,901	100,409
102	Nuclear Outage Accounting	39,460	40,472	41,642
103	Avoided Tax Interest	10,191	7,222	10,853
104	Other Book Additions	5,656	5,656	5,656
105	**Total Tax Additions**	807,203	789,836	804,275
106				
107	**Tax Deductions**			
108	Total Rate Base	9,950,576	10,267,755	10,656,235
109	Weighted Cost of Debt	1.99%	1.98%	1.97%
110	Debt Interest Expense	198,016	203,302	209,928
111	Nuclear Outage Accounting	54,004	29,263	54,034
112	Tax Depreciation and Removals	1,202,284	1,050,786	952,344
113	NOL Utilized / (Generated)			
114	Other Tax / Book Timing Differences	1,832	6,154	1,385
115	**Total Tax Deductions**	**1,456,137**	**1,289,504**	**1,217,691**
116				
117	**State Taxes**			
118	State Taxable Income	(319,299)	(171,560)	(150,586)
119	State Income Tax Rate	9.80%	9.80%	9.80%
120	State Taxes before Credits	(31,291)	(16,813)	(14,757)
121	Less State Tax Credits applied	(1,067)	(1,473)	(1,701)
122	**Total State Income Taxes**	(32,358)	(18,286)	(16,459)
123				
124	**Federal Taxes**			
125	Federal Sec 199 Production Deduction			
126	Federal Taxable Income	(286,941)	(153,274)	(134,127)
127	Federal Income Tax Rate	21.00%	21.00%	21.00%
128	Federal Tax before Credits	(60,258)	(32,188)	(28,167)
129	Less Federal Tax Credits	8,512	9,336	(16,858)
130	**Total Federal Income Taxes**	(51,746)	(22,852)	(45,025)
131				
132	**Total Taxes**			
133	Total Taxes Other than Income	135,271	82,667	95,041
134	Total Federal and State Income Taxes	(84,104)	(41,137)	(61,484)
135	**Total Taxes**	51,167	41,530	33,557
136				
137	**Total Operating Revenues**	**3,610,268**	**3,616,971**	**3,599,829**
138	**Total Expenses**	**3,196,529**	**3,247,726**	**3,275,514**
139				
140	AFDC Debt	8,547	7,605	9,400
141	AFDC Equity	19,951	17,460	21,724
142				
143	**Net Income**	**442,237**	**394,310**	**355,438**

COST OF SERVICE SUMMARY for 2021-2023 MYRP FORECAST ($000's)

Line No.		Minnesota Electric Jurisdiction		
		2021 Test Year	2022 Plan Year	2023 Plan Year
144				
145	**Rate of Return (ROR)**			
146	Total Operating Income	442,237	394,310	355,438
147	Total Rate Base	9,950,576	10,267,755	10,656,235
148	**ROR (Operating Income / Rate Base)**	4.44%	3.84%	3.34%
149				
150	**Return on Equity (ROE)**			
151	Net Operating Income	442,237	394,310	355,438
152	Debt Interest (Rate Base * Weighted Cost of Debt)	(198,016)	(203,302)	(209,928)
153	Earnings Available for Common	244,220	191,009	145,510
154	Equity Rate Base (Rate Base * Equity Ratio)	5,224,052	5,390,571	5,594,524
155	**ROE (earnings for Common / Equity)**	4.67%	3.54%	2.60%
156				
157	**Revenue Deficiency**			
158	Required Operating Income (Rate Base * Required Return)	731,367	753,653	781,102
159	Net Operating Income	442,237	394,310	355,438
160	**Operating Income Deficiency**	289,131	359,343	425,664
161				
162	Revenue Conversion Factor (1/(1--Composite Tax Rate))	1.403351	1.403351	1.403351
163	**Revenue Deficiency (Income Deficiency * Conversion Factor)**	**405,752**	**504,284**	**597,356**
164				
165	**Total Revenue Requirements**			
166	Total Retail Revenues	3,064,643	3,053,834	3,031,362
167	Revenue Deficiency	405,752	504,284	597,356
168	Total Revenue Requirements	3,470,395	3,558,119	3,628,719
169				
170				
171	**Excluding Fuel Clause Expense and Revenue**			
172	Base Cost of Energy	749,743	749,743	749,743
173	Line 137 - Total Operating Revenue	2,860,525	2,867,228	2,850,086
174	Line 138 - Total Operating Expense	2,446,786	2,497,983	2,525,771
175	Line 143 - Net Income	442,237	394,310	355,438
176	Change	(0)	0	(0)

Line No.	Summary Cash Working Capital		Lead/Lag Days	Minnesota Electric Jurisdiction: 2021 Test Year Dollars	2021 Test Year Dollar x Days	2022 Plan Year Dollars	2022 Plan Year Dollar x Days	2023 Plan Year Dollars	2023 Plan Year Dollar x Days
1	**Fuel Expenses**								
2	Coal and Rail Transport		19.13	130,588	2,498,146	130,588	2,498,146	130,588	2,498,146
3	Gas for Generation		39.34	158,981	6,254,330	158,981	6,254,330	158,981	6,254,330
4	Oil		11.50	12	141	12	141	12	141
5	Nuclear and EOL			99,356		99,356		99,356	
6	**Subtotal Fuel Expenses**			**388,937**	**8,752,617**	**388,937**	**8,752,617**	**388,937**	**8,752,617**
7	**Purchased Power**								
8	Purchases		39.69	632,569	25,106,656	635,382	25,218,302	635,507	25,223,291
9	Interchange		37.29	162,264	6,050,840	170,398	6,354,150	185,898	6,932,126
10	**SubTotal Purchased Power**			**794,833**	**31,157,497**	**805,780**	**31,572,452**	**821,405**	**32,155,417**
11	**Labor and Related**								
12	Regular Payroll		11.90	376,014	4,474,570	373,234	4,441,485	376,393	4,479,080
13	Incentive		248.78	14,180	3,527,808	14,606	3,633,636	15,044	3,742,647
14	Pension and Benefits		37.29	66,638	2,484,939	66,315	2,472,891	67,820	2,529,014
15	**SubTotal Labor and Related**			**456,833**	**10,487,316**	**454,155**	**10,548,012**	**459,257**	**10,750,741**
				-	-	-	-	-	-
16	All Other Operating Expenses		39.25	820,570	32,207,367	848,423	33,300,621	850,528	33,383,237
17	Property taxes		356.83	192,908	68,835,272	204,206	72,866,692	216,712	77,329,337
18	Employer's Payroll Taxes		30.14	27,815	838,358	28,067	845,937	28,308	853,195
19	Gross Earnings Tax		59.87	90,658	5,427,706	90,658	5,427,706	90,658	5,427,706
20	Federal Income Tax		37.50	(76,148)	(2,855,560)	(87,866)	(3,294,991)	(97,656)	(3,662,117)
21	State Income Tax		29.75	(39,336)	(1,170,238)	(33,392)	(993,406)	(24,920)	(741,364)
22	State Sales Tax Customer Billings		35.23	142,360	5,015,334	142,360	5,015,334	142,360	5,015,334
23	**Total Expenses**	A		**2,799,430**	**158,695,669**	**2,841,328**	**164,040,975**	**2,875,590**	**169,264,104**
24	Net Annual Expense			56.69	434,783	57.73	449,427	58.86	463,737
25	**Revenues**								
26	Retail Revenue		38.67	3,114,246	120,427,903	3,116,128	120,500,688	3,108,957	120,223,382
27	Late Payment		-	5,448		5,448		5,448	
28	Interdepartmental		-	456		456		456	
29	Misc Services		38.67	3,052	118,028	3,502	135,405	4,302	166,351
30	Rentals		(100.20)	4,665	(467,404)	4,712	(472,119)	4,760	(476,996)
31	Interchange		37.29	406,719	15,166,569	415,951	15,510,794	420,177	15,668,415
32	Retail Rev Lag Days		38.67	16,346	632,112	14,516	561,319	12,337	477,080
33	MISO		14.00	5,567	77,944	5,434	76,074	5,439	76,147
34	Wholesale Lag Days		34.06	203,988	6,947,840	214,393	7,302,241	215,853	7,351,948
35	**Total Revenues**	B		**3,760,489**	**142,902,991**	**3,780,540**	**143,614,403**	**3,777,730**	**143,486,326**
36	Net Annual Amount			38.00	391,515	37.99	393,464	37.98	393,113
37	Expense/Revenue Factor	C = A/B			74.443%		75.157%		76.120%
38	Allocated Revenue Amount	D = B * C			291,457		295,715		299,236
39	**Net Cash Working Capital**	E = D - A			**(143,326)**		**(153,713)**		**(164,501)**

LABELING OF FINANCIAL SOURCES

Xcel Energy or XEI
The entire enterprise – XES, NSPM, NSPW, SPS, PSCo, and affiliate companies.

XES: Xcel Energy Services
Xcel Energy's service company that provides services across all Xcel Energy affiliate companies.

NSPM (Total Company)
Northern States Power Company-Minnesota providing service to electric and gas customers in Minnesota, North Dakota, and South Dakota.

NSPW (Total Company)
Northern States Power Company-Wisconsin providing service to electric and gas customers in Wisconsin and Michigan.

NSP System
The combined NSPM and NSPW electric production and transmission system.

NSPM Electric
Northern States Power Company, including the portion allocated or direct assigned to the electric utility.

State of Minnesota
Items physically located in the State of Minnesota, such as distribution facilities or property taxes assessed by the State.

State of Minnesota Electric Jurisdiction
Amounts direct assigned or allocated to the electric utility and to the State of Minnesota. Interchange Agreement billings to and from NSPW are reflected in revenues and expenses, respectively.

State of Minnesota Electric Jurisdiction net of Interchange Agreement billings to NSPW
Or, State of Minnesota Electric Jurisdiction, net of Interchange
The net amount allocated to the cost of service for electric customers in the State of Minnesota. The portion of the item billed to NSPW through the Interchange Agreement has been netted against the item to show the net impact to Minnesota electric customers.

Notes:

1. Jurisdictional numbers will be provided where practicable.
2. The table below shows the typical financial basis from which the allocations are being made, unless otherwise specified.

Order	Topic	Witness	Financial Source
1	Policy / MYRP Policy	Chamberlain	NSPM Electric
2	Performance Based Rates (PBR)	Orans	N/A
3	Revenue Requirements	Halama	State of MN Electric Jurisdiction
4	Capital Structure	Soong	NSPM (Total Company)
5	Return on Equity	D'Ascendis	State of MN Electric Jurisdiction
6	Budgeting	Ostrom	NSPM Electric
7	Sales Forecast	Marks	NSPM Electric
8	Nuclear Operations	Gardner	NSPM Electric
9	Transmission	Benson	NSPM Electric
10	Energy Supply	Randolph	NSPM Electric
11	Distribution	Bloch	NSPM Electric / State of MN Electric Jurisdiction
12	Business Systems	Reimer	NSPM (Total Company)
13	Customer Care/Bad Debt	Cardenas	NSPM Electric
14	Cost Allocations	Baumgarten	NSPM Electric
15	Property Tax	Arend	NSPM (Total Company)
16	Insurance	Miller	XEI and NSPM (Total Company)
17	Employee Expenses	Husen	NSPM (Total Company)
18	Pension	Schrubbe	State of MN Electric Jurisdiction
19	Pension Investments	Inglis	N/A
20	Compensation and Benefits	Lowenthal	Xcel Energy, NSPM (Total Company), and NSPM Electric
21	Depreciation	Moeller	NSPM Electric
22	CCOSS	Peppin	State of MN Electric Jurisdiction
23	Rate Design/Decoupling	Huso	State of MN Electric Jurisdiction

Northern States Power Company
Electric Utility - State of Minnesota

DETAILED CASE DRIVERS

Test Year Drivers - Revenue Requirements - Incremental
Amounts in millions

	Increase (Decrease) 2021 TY to 2019 MYRP	Increase (Decrease) 2022 TY to 2021 TY	Increase (Decrease) 2023 TY to 2022 TY	**3-Year MYRP**
Capital Related				
Nuclear	36.9	5.5	6.4	48.8
Steam	(17.8)	3.9	(19.6)	(33.5)
Wind	156.1	(6.0)	(10.5)	139.6
All Other Production	1.3	2.7	4.7	8.7
Transmission	68.4	10.4	9.4	88.1
Distribution	33.1	24.4	24.8	82.3
General and Intangible	28.1	13.6	8.7	50.5
DTA (Federal Credits & NOL)	9.9	10.7	9.9	30.5
Other Rate Base	(0.2)	(0.3)	(0.3)	(0.8)
Cost of Capital	83.8	2.7	3.3	89.7
TOTAL Capital Related	399.7	67.5	36.8	503.9
Amortizations	11.2	-	(2.1)	9.1
Taxes				
Taxes - Other	10.0	13.2	5.1	28.4
PTCs	(103.5)	(5.0)	(0.0)	(108.5)
Property Tax	(6.9)	9.5	12.5	15.1
Payroll Tax	(2.1)	0.3	0.2	(1.6)
TOTAL Taxes	(102.4)	17.9	17.8	(66.7)
Operating Expense				
Nuclear	(61.4)	1.2	2.5	(57.6)
Steam	(42.1)	(3.5)	5.8	(39.8)
Wind	23.5	0.7	0.1	24.3
Purchased Demand	12.1	2.8	0.1	15.0
All Other Production	19.5	1.3	10.9	31.7
Transmission	29.1	5.0	3.0	37.2
Transmission Interchange	(25.6)	6.9	4.4	(14.3)
Distribution	16.2	5.6	2.7	24.5
Regional Markets	2.4	(0.2)	0.4	2.6
Customer Accounting / Info / Service	8.4	(6.3)	(10.6)	(8.5)
A&G	1.0	9.9	3.3	14.2
TOTAL O&M	(17.0)	23.4	22.9	29.3
Other Margin Impacts				
Sales Change	171.1	(6.4)	10.6	175.3
Rider Revenue and Other Revenue	(56.8)	(3.8)	7.1	(53.5)
TOTAL Other Margin Impacts	114.3	(10.2)	17.7	121.8
TOTAL Net Incremental Deficiency	**405.8**	**98.5**	**93.1**	**597.4**

COMPARISON OF DETAILED RATE BASE COMPONENTS
Test Year Ending December 31, 2021
($000's)

Line No.	Description	General Rate Case Filing Docket No. E002/GR-15-826 (A)	General Rate Case Filing Docket No. E002/GR-20-723 Final Rates (B)	Change (C) = (B) - (A)
	Electric Plant as Booked			
1	Production	$10,060,608	$12,031,701	$1,971,093
2	Transmission	2,397,725	3,445,539	1,047,814
3	Distribution	3,658,370	4,087,440	429,070
4	General	888,530	976,773	88,242
5	Common	781,187	849,540	68,353
6	TOTAL Utility Plant in Service	$17,786,420	$21,390,993	$3,604,573
	Reserve for Depreciation			
7	Production	$6,015,790	$6,728,023	$712,233
8	Transmission	619,062	775,371	156,309
9	Distribution	1,391,483	1,496,030	104,547
10	General	451,746	509,524	57,778
11	Common	412,713	391,689	(21,024)
12	TOTAL Reserve for Depreciation	$8,890,795	$9,900,637	$1,009,843
	Net Utility Plant in Service			
13	Production	$4,044,818	$5,303,678	$1,258,860
14	Transmission	$1,778,663	2,670,168	891,505
15	Distribution	$2,266,887	2,591,410	324,523
16	General	$436,784	467,249	30,465
17	Common	$368,473	457,850	89,377
18	Net Utility Plant in Service	$8,895,625	$11,490,356	$2,594,731
19	Utility Plant Held for Future Use	$0	$0	$0
20	Construction Work in Progress	$380,350	$394,160	$13,809
21	Less: Accumulated Deferred Income Taxes	$2,302,072	$2,245,198	($56,874)
22	Cash Working Capital	($111,130)	($143,326)	($32,196)
	Other Rate Base Items:			
23	Materials and Supplies	$135,797	$152,207	$16,409
24	Fuel Inventory	73,476	84,026	10,550
25	Non-Plant Assets & Liabilities	27,456	104,503	77,046
26	Customer Advances	(5,562)	(7,575)	(2,014)
27	Interest on Customer Deposits	(28,127)	(44,786)	(16,658)
28	Prepaids and Other	85,941	70,039	(15,902)
29	Regulatory Amortizations	$50,579	96,171	45,592
30	Total Other Rate Base Items	$339,561	$454,585	$115,024
31	Total Average Rate Base	$7,202,334	$9,950,576	$2,748,242

Northern States Power Company

Docket No. E002/GR-20-723
Exhibit___(BCH-1), Schedule 7

RATE BASE SCHEDULES

Detailed Rate Base Components
($000's)

Line No.	Description	2021 Test Year Adjusted	2022 Plan Year Adjusted	2023 Plan Year Adjusted
	Electric Plant as Booked			
1	Production	$12,031,701	$12,244,456	$12,391,493
2	Transmission	3,445,539	3,592,979	3,743,932
3	Distribution	4,087,440	4,371,330	4,673,765
4	General	976,773	1,052,623	1,129,397
5	Common	849,540	990,884	1,128,391
6	TOTAL Utility Plant in Service	$21,390,993	$22,252,272	$23,066,979
	Reserve for Depreciation			
7	Production	$6,728,023	$7,119,351	$7,511,111
8	Transmission	775,371	835,805	898,294
9	Distribution	1,496,030	1,569,707	1,647,751
10	General	509,524	572,822	636,129
11	Common	391,689	468,825	551,946
12	TOTAL Reserve for Depreciation	$9,900,637	$10,566,509	$11,245,231
	Net Utility Plant in Service			
13	Production	$5,303,678	$5,125,106	$4,880,383
14	Transmission	2,670,168	2,757,174	2,845,638
15	Distribution	2,591,410	2,801,623	3,026,015
16	General	467,249	479,801	493,268
17	Common	457,850	522,059	576,445
18	Net Utility Plant in Service	$11,490,356	$11,685,763	$11,821,748
19	Utility Plant Held for Future Use	$0	$0	$0
20	Construction Work in Progress	$394,160	$417,943	$532,577
21	Less: Accumulated Deferred Income Taxes	$2,245,198	$2,147,245	$2,008,583
22	Cash Working Capital	($143,326)	($153,713)	($164,501)
	Other Rate Base Items:			
23	Materials and Supplies	$152,207	$152,207	$152,207
24	Fuel Inventory	84,026	84,026	84,026
25	Non-Plant Assets & Liabilities	104,503	122,703	140,883
26	Customer Advances	(7,575)	(7,575)	(7,575)
27	Interest on Customer Deposits	(44,786)	(44,786)	(44,786)
28	Prepaids and Other	70,039	71,706	72,297
29	Regulatory Amortizations	96,171	86,726	77,943
30	Total Other Rate Base Items	$454,585	$465,007	$474,995
31	Total Average Rate Base	$9,950,576	$10,267,755	$10,656,235

STATEMENT OF OPERATING INCOME
2019 Final Compliance versus 2021 Test Year
($000s)

Line No.	Description	General Rate Case Filing E002/GR-15-826 Final Rates (A)	General Rate Case Filing E002/GR-20-723 Test Year (B)	Change (C) = (B) - (A)
	Operating Revenues			
1	Retail	3,051,778	3,064,187	$12,409
3	Interdepartmental	672	456	(216)
4	Other Operating	687,000	545,625	(141,375)
5	Gross Earnings Tax	0	0	0
6	**Total Operating Revenues**	$3,739,450	$3,610,268	($129,182)
	Expenses			
	Operating Expenses:			
7	Fuel & Purchased Energy	$1,125,206	$919,984	($205,222)
8	Power Production	691,533	645,519	(46,014)
9	Transmission	243,697	247,205	3,509
10	Distribution	111,186	127,374	16,189
11	Customer Accounting	50,555	58,738	8,183
12	Customer Service & Information	95,067	128,469	33,402
13	Sales, Econ Dvlp & Other	69	282	213
14	Administrative & General	224,433	225,387	955
15	Total Operating Expenses	$2,541,744	$2,352,958	($188,785)
16	Depreciation	$568,522	$737,364	$168,842
17	Amortizations	21,871	$55,040	33,169
	Taxes:			
18	Property	$198,796	$191,930	($6,866)
19	Gross Earnings	0	0	0
20	Deferred Income Tax & ITC	107,334	(84,474)	(191,808)
21	Federal & State Income Tax	(67,264)	(84,104)	(16,840)
22	Payroll & Other	29,896	27,815	(2,080)
23	Total Taxes	$268,761	$51,167	($217,594)
24	**Total Expenses**	$3,400,898	$3,196,529	($204,369)
25	AFUDC	$27,894	$28,498	$604
26	**Total Operating Income**	$366,445	$442,237	$75,791

Note: Revenues reflect calendar month sales.

STATEMENT OF OPERATING INCOME
2021 Test Year, 2022-2023 Plan Years
($000s)

Line No.	Description	2021 Test Year (A)	2022 Plan Year (B)	2023 Plan Year (C)
	Operating Revenues			
1	Retail	3,064,187	3,053,378	3,030,907
3	Interdepartmental	456	456	456
4	Other Operating	545,625	563,137	568,466
5	Gross Earnings Tax	0	0	0
6	**Total Operating Revenues**	$3,610,268	$3,616,971	$3,599,829
	Expenses			
	Operating Expenses:			
7	Fuel & Purchased Energy	$919,984	$919,838	$920,319
8	Power Production	645,519	647,857	667,835
9	Transmission	247,205	259,111	266,511
10	Distribution	127,374	132,937	135,655
11	Customer Accounting	58,738	52,401	41,826
12	Customer Service & Information	128,469	128,545	128,615
13	Sales, Econ Dvlp & Other	282	284	283
14	Administrative & General	225,387	235,276	238,616
15	Total Operating Expenses	$2,352,958	$2,376,248	$2,399,661
16	Depreciation	737,364	778,372	792,829
17	Amortizations	55,040	51,576	49,467
	Taxes:			
18	Property	$191,930	$201,387	$213,848
19	Gross Earnings	0	0	0
20	Deferred Income Tax & ITC	(84,474)	(146,787)	(147,115)
21	Federal & State Income Tax	(84,104)	(41,137)	(61,484)
22	Payroll & Other	27,815	28,067	28,308
23	Total Taxes	$51,167	$41,530	$33,557
24	**Total Expenses**	$3,196,529	$3,247,726	$3,275,514
25	AFUDC	$28,498	$25,065	$31,124
26	**Total Operating Income**	$442,237	$394,310	$355,438

Note: Revenues reflect calendar month sales.

RATE BASE SCHEDULES
Detailed Rate Base Components
($000's)

		Proposed Test Year 2021					
		Total Utility			Minnesota Jurisdiction		
Line No.	Description	Unadjusted (A)	Adjustments (B)	Adjusted (C) (A) + (B)	Unadjusted (D)	Adjustments (E)	Adjusted (F) (D) + (E)
	Electric Plant as Booked						
1	Production	$14,147,508	($236,432)	$13,911,076	$12,268,133	($236,432)	$12,031,701
2	Transmission	4,002,370	(34,673)	3,967,697	3,480,212	(34,673)	3,445,539
3	Distribution	4,659,629	(5,364)	4,654,265	4,092,804	(5,364)	4,087,440
4	General	1,162,508	(35,522)	1,126,986	1,012,295	(35,522)	976,773
5	Common	975,526	0	975,526	849,540	0	849,540
6	TOTAL Utility Plant in Service	$24,947,541	($311,991)	$24,635,549	$21,702,984	($311,991)	$21,390,993
	Reserve for Depreciation						
7	Production	$7,746,815	($1,931)	$7,744,885	$6,730,242	($2,219)	$6,728,023
8	Transmission	914,141	(177)	913,964	775,545	(174)	775,371
9	Distribution	1,687,026	4	1,687,031	1,496,026	4	1,496,030
10	General	588,412	(2,578)	585,835	512,104	(2,581)	509,524
11	Common	449,034	733	449,767	391,051	638	391,689
12	TOTAL Reserve for Depreciation	$11,385,428	($3,948)	$11,381,480	$9,904,968	($4,331)	$9,900,637
	Net Utility Plant in Service						
13	Production	$6,400,693	($234,501)	$6,166,191	$5,537,891	($234,213)	$5,303,678
14	Transmission	3,088,230	(34,497)	3,053,733	2,704,667	(34,500)	2,670,168
15	Distribution	2,972,603	(5,368)	2,967,234	2,596,779	(5,368)	2,591,410
16	General	574,096	(32,944)	541,152	500,190	(32,941)	467,249
17	Common	526,492	(733)	525,759	458,489	(638)	457,850
18	Net Utility Plant in Service	$13,562,113	($308,043)	$13,254,069	$11,798,016	($307,660)	$11,490,356
19	Utility Plant Held for Future Use	$0	$0	$0	$0	$0	$0
20	Construction Work in Progress	$649,837	($171,825)	$478,012	$565,984	($171,825)	$394,160
21	Less: Accumulated Deferred Income Taxes	$2,510,820	$30,530	$2,541,351	$2,216,247	$28,952	$2,245,198
22	Cash Working Capital	($174,802)	$15,085	($159,717)	($156,497)	$13,171	($143,326)
	Other Rate Base Items:						
23	Materials and Supplies	$174,923	$0	$174,923	$152,207	$0	$152,207
24	Fuel Inventory	97,123	0	97,123	84,026	0	84,026
25	Non-Plant Assets & Liabilities	87,261	30,526	117,786	73,977	30,526	104,503
26	Customer Advances	(9,170)	0	(9,170)	(7,575)	0	(7,575)
27	Interest on Customer Deposits	(44,930)	0	(44,930)	(44,786)	0	(44,786)
28	Prepaids and Other	80,617	0	80,617	70,039	0	70,039
29	Regulatory Amortizations	0	104,497	104,497	0	96,171	96,171
33	Total Other Rate Base Items	$385,824	$135,022	$520,846	$327,888	$126,697	$454,585
34	Total Average Rate Base	$11,912,151	($360,291)	$11,551,859	$10,319,145	($368,569)	$9,950,576

Northern States Power Company

Docket No. E002/GR-20-723
Exhibit___(BCH-1), Schedule 9

RATE BASE SCHEDULES
Detailed Rate Base Components
($000's)

Line No.	Description	Adjusted Plan Year 2022 Total Utility (A)	Adjusted Plan Year 2022 Minnesota Jurisdiction (B)	Adjusted Plan Year 2023 Total Utility (C)	Adjusted Plan Year 2023 Minnesota Jurisdiction (D)
	Electric Plant as Booked				
1	Production	$14,194,504	$12,244,456	$14,363,154	$12,391,493
2	Transmission	4,142,909	3,592,979	4,316,607	3,743,932
3	Distribution	4,972,757	4,371,330	5,319,958	4,673,765
4	General	1,220,735	1,052,623	1,313,837	1,129,397
5	Common	1,137,835	990,884	1,295,739	1,128,391
6	TOTAL Utility Plant in Service	$25,668,741	$22,252,272	$26,609,296	$23,066,979
	Reserve for Depreciation				
7	Production	$8,198,654	$7,119,351	$8,653,928	$7,511,111
8	Transmission	983,655	835,805	1,055,829	898,294
9	Distribution	1,771,189	1,569,707	1,860,160	1,647,751
10	General	659,458	572,822	733,866	636,129
11	Common	538,340	468,825	633,787	551,946
12	TOTAL Reserve for Depreciation	$12,151,296	$10,566,509	$12,937,571	$11,245,231
	Net Utility Plant in Service				
13	Production	$5,995,851	$5,125,106	$5,709,226	$4,880,383
14	Transmission	3,159,254	2,757,174	3,260,778	2,845,638
15	Distribution	3,201,568	2,801,623	3,459,798	3,026,015
16	General	561,277	479,801	579,971	493,268
17	Common	599,494	522,059	661,951	576,445
18	Net Utility Plant in Service	$13,517,444	$11,685,763	$13,671,724	$11,821,748
19	Utility Plant Held for Future Use	$0	$0	$0	$0
20	Construction Work in Progress	$483,736	$417,943	$618,522	$532,577
21	Less: Accumulated Deferred Income Taxes	$2,435,667	$2,147,245	$2,284,911	$2,008,583
22	Cash Working Capital	($171,181)	($153,713)	($183,031)	($164,502)
	Other Rate Base Items:				
23	Materials and Supplies	$174,923	$152,207	$174,923	$152,207
24	Fuel Inventory	97,123	84,026	97,123	84,026
25	Non-Plant Assets & Liabilities	137,411	122,703	157,331	140,883
26	Customer Advances	(9,170)	(7,575)	(9,170)	(7,575)
27	Interest on Customer Deposits	(44,930)	(44,786)	(44,930)	(44,786)
28	Prepaids and Other	82,539	71,706	83,207	72,297
29	Regulatory Amortizations	94,624	86,726	85,414	77,943
30	Total Other Rate Base Items	$532,521	$465,007	$543,898	$474,995
31	Total Average Rate Base	$11,926,853	$10,267,755	$12,366,202	$10,656,235

COMPARISON OF DETAILED RATE BASE COMPONENTS
Test Year Ending December 31, 2021
($000's)

Line No.	Description	Proposed Test Year 2021					
		Total Utility			Minnesota Jurisdiction *		
		Unadjusted (A)	Adjustments (B)	Total (A) + (B)	Unadjusted (D)	Adjustments (E)	Total (D) + (E)
	Construction Work in Progress						
1	Production	$406,390	($140,408)	$265,982	$351,672	($140,408)	$211,264
2	Transmission	56,464	(17,643)	38,821	48,718	(17,643)	31,075
3	Distribution	67,572	(399)	67,173	61,615	(399)	61,216
4	General	71,408	(13,374)	58,034	62,177	(13,374)	48,803
5	Common	48,002	0	48,002	41,803	0	41,803
6	TOTAL Construction Work In Progress	$649,837	($171,825)	$478,012	$565,984	($171,825)	$394,160

Line No.	Description	Plan Year 2022					
		Total Utility			Minnesota Jurisdiction *		
		Unadjusted (A)	Adjustments (B)	Total (A) + (B)	Unadjusted (D)	Adjustments (E)	Total (D) + (E)
	Construction Work in Progress						
7	Production	$229,289	$0	$229,289	$199,444	$0	$199,444
8	Transmission	89,310	4	89,314	77,725	4	77,729
9	Distribution	60,420	106	60,526	49,804	106	49,910
10	General	53,327	(1,901)	51,426	46,448	(1,901)	44,546
11	Common	53,180	0	53,180	46,313	0	46,313
12	TOTAL Construction Work In Progress	$485,527	($1,791)	$483,736	$419,734	($1,791)	$417,943

Line No.	Description	Plan Year 2023					
		Total Utility			Minnesota Jurisdiction *		
		Unadjusted (A)	Adjustments (B)	Total (A) + (B)	Unadjusted (D)	Adjustments (E)	Total (D) + (E)
	Construction Work in Progress						
13	Production	$259,122	$0	$259,122	$225,374	$0	$225,374
14	Transmission	183,650	0	183,650	159,802	0	159,802
15	Distribution	72,781	117	72,898	58,418	117	58,535
16	General	59,323	(5,692)	53,632	51,691	(5,692)	45,999
17	Common	49,221	0	49,221	42,867	0	42,867
18	TOTAL Construction Work In Progress	$624,097	($5,575)	$618,522	$538,152	($5,575)	$532,577

(*) See Volume 3, Rate Base Section, Schedule E for allocation factors.

COMPARISON OF DETAILED RATE BASE COMPONENTS
Test Year Ending December 31, 2021
($000's)

Line No.	Description	Proposed Test Year 2021					
		Total Utility			Minnesota Jurisdiction *		
		Unadjusted (A)	Adjustments (B)	Total (A) + (B)	Unadjusted (D)	Adjustments (E)	Total (D) + (E)
	Accumulated Deferred Income Taxes						
1	Production	$1,338,700	$15,003	$1,353,703	$1,159,889	$15,007	$1,174,896
2	Transmission	836,242	1,493	837,734	734,959	1,558	736,517
3	Distribution	681,889	(656)	681,234	595,947	(670)	595,277
4	General	88,062	(1,594)	86,467	76,923	(1,621)	75,302
5	Common	78,883	(309)	78,573	68,715	(288)	68,427
6	Net Operating Loss (NOL)	(541,065)	8,013	(533,052)	(445,046)	6,384	(438,661)
7	Non-Plant Related	28,110	8,580	36,691	24,859	8,580	33,439
8	TOTAL Accum Deferred Income Taxes	$2,510,820	$30,530	$2,541,351	$2,216,247	$28,952	$2,245,198

Line No.	Description	Plan Year 2022					
		Total Utility			Minnesota Jurisdiction *		
		Unadjusted (A)	Adjustments (B)	Total (A) + (B)	Unadjusted (D)	Adjustments (E)	Total (D) + (E)
	Accumulated Deferred Income Taxes						
9	Production	$1,430,750	($15,829)	$1,414,920	$1,241,277	($17,286)	$1,223,991
10	Transmission	849,778	3,650	853,428	744,425	5,634	750,059
11	Distribution	677,517	(1,261)	676,256	592,379	(1,292)	591,087
12	General	90,248	(4,753)	85,495	79,675	(5,497)	74,178
13	Common	77,709	306	78,015	67,124	818	67,941
14	Net Operating Loss (NOL)	(723,806)	10,294	(713,513)	(605,883)	8,459	(597,425)
15	Non-Plant Related	32,446	8,619	41,065	28,794	8,619	37,413
16	TOTAL Accum Deferred Income Taxes	$2,434,642	$1,025	$2,435,667	$2,147,791	($545)	$2,147,245

Line No.	Description	Plan Year 2023					
		Total Utility			Minnesota Jurisdiction *		
		Unadjusted (A)	Adjustments (B)	Total (A) + (B)	Unadjusted (D)	Adjustments (E)	Total (D) + (E)
	Accumulated Deferred Income Taxes						
17	Production	$1,459,136	($39,671)	$1,419,466	$1,264,590	($41,453)	$1,223,138
18	Transmission	868,806	(7,555)	861,250	762,884	(6,176)	756,708
19	Distribution	678,292	(2,604)	675,689	593,322	(2,516)	590,806
20	General	93,070	(8,146)	84,924	80,993	(7,760)	73,233
21	Common	81,764	(2,160)	79,604	71,075	(1,751)	69,325
22	Net Operating Loss (NOL)	(894,136)	12,589	(881,547)	(756,440)	10,431	(746,010)
23	Non-Plant Related	37,020	8,505	45,525	32,878	8,505	41,384
24	TOTAL Accum Deferred Income Taxes	$2,323,953	($39,042)	$2,284,911	$2,049,303	($40,720)	$2,008,583

(*) See Volume 3, Rate Base Section, Schedule E for allocation factors.

Northern States Power Company

RATE BASE
RATE BASE ADJUSTMENT SCHEDULES
2021 Unadjusted Test Year versus Final Adjusted Test Year
($000's)

		Bridge - Unadjusted					Adjustments			Amortization									Secondary Calculations				
Line No.	NSPM - 11 Bridge by Report Label	Unadjusted w/o NOL & 199 at Last Authorized	ADIT Prorate for IRS	Cash Working Capital	Net Operating Loss	Total Unadjusted at Last Authorized	Depreciation Study: Remaining Life	Depreciation Study: TD&G	Pension: Extend Deferral	Aurora	Electric Vehicle	Income Tax Tracker	LED Street Lighting	NOL ADIT ARAM	PI EPU Recovery	Sherco 3 Depr Deferral	Rider: RES	Rider: TCR	ADIT Prorate for IRS	Cash Working Capital	Change in Cost of Capital	Net Operating Loss	Total
	Work Paper Reference						WP A-26	WP A-27	WP A-33	WP A-35	WP A-36	WP A-37	WP A-38	WP A-39	WP A-40	WP A-42	WP A-44	WP A-45	WP A-47	WP A-48	WP A-50	WP A-49	
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)
(1)																							
(2)	Plant as booked																						
(3)	Production	12,268,133				12,268,133											(236,432)						12,031,701
(4)	Transmission	3,480,212				3,480,212											(8,196)	(26,477)					3,445,539
(5)	Distribution	4,092,804				4,092,804												(5,364)					4,087,440
(6)	General	1,012,295				1,012,295												(35,522)					976,773
(7)	Common	849,540				849,540																	849,540
(8)	Total Utility Plant in Service	21,702,984				21,702,984											(244,628)	(67,363)					21,390,993
(9)																							
(10)	Reserve for Depreciation																						
(11)	Production	6,730,242				6,730,242	1,881										(4,100)						6,728,023
(12)	Transmission	775,545				775,545		(21)									(72)	(81)					775,371
(13)	Distribution	1,496,026				1,496,026		191										(186)					1,496,030
(14)	General	512,104				512,104		21										(2,602)					509,524
(15)	Common	391,051				391,051		638															391,689
(16)	Total Reserve for Depreciation	9,904,968				9,904,968	1,881	829									(4,172)	(2,869)					9,900,637
(17)																							
(18)	Net Utility Plant																						
(19)	Production	5,537,891				5,537,891	(1,881)										(232,332)						5,303,678
(20)	Transmission	2,704,667				2,704,667		21									(8,124)	(26,397)					2,670,168
(21)	Distribution	2,596,779				2,596,779		(191)										(5,178)					2,591,410
(22)	General	500,190				500,190		(21)										(32,920)					467,249
(23)	Common	458,489				458,489		(638)															457,850
(24)	Net Utility Plant in Service	11,798,016				11,798,016	(1,881)	(829)									(240,456)	(64,495)					11,490,356
(25)																							
(26)	Utility Plant Held for Future Use																						
(27)																							
(28)	Construction Work in Progress	565,984				565,984											(144,777)	(27,048)					394,160
(29)																							
(30)	Less: Accumulated Deferred Income Taxes	2,535,986	(32,141)		(306,400)	2,197,444	(529)	(233)	8,580						15,131	2,771	(8,882)	(1,620)	13,268			19,267	2,245,198
(31)																							
(32)	Other Rate Base Items																						
(33)	Cash Working Capital			(156,391)		(156,391)														13,064			(143,326)
(34)	Materials and Supplies	152,207				152,207																	152,207
(35)	Fuel Inventory	84,026				84,026																	84,026
(36)	Non Plant Assets and Liabilities	73,977				73,977			30,526														104,503
(37)	Customer Advances	(7,575)				(7,575)																	(7,575)
(38)	Customer Deposits	(44,786)				(44,786)																	(44,786)
(39)	Prepayments	70,039				70,039																	70,039
(40)	Regulatory Amortizations									2,079	622	5,001	425	44,240	37,012	6,792							96,171
(41)	Total Other Rate Base	327,888		(156,391)		171,497			30,526	2,079	622	5,001	425	44,240	37,012	6,792				13,064			311,259
(42)																							
(43)	Total Average Rate Base	10,155,903	32,141	(156,391)	306,400	10,338,053	(1,352)	(596)	21,945	2,079	622	5,001	425	44,240	21,882	4,021	(376,350)	(89,922)	(13,268)	13,064		(19,267)	9,950,576

RATE BASE
RATE BASE ADJUSTMENT SCHEDULES
2022 Unadjusted Test Year versus Final Adjusted Test Year
($000's)

Line No.	NSPM - 11 Bridge by Report Label	Bridge - Unadjusted					Adjustments			Amortization									Secondary Calculations				Total
		Unadjusted w/o NOL & 199 at Last Authorized	ADIT Prorate for IRS	Cash Working Capital	Net Operating Loss	Total Unadjusted at Last Authorized	Depreciation Study: Remaining Life	Depreciation Study: TD&G	Pension: Extend Deferral	Aurora	Electric Vehicle	Income Tax Tracker	LED Street Lighting	NOL ADIT ARAM	PI EPU Recovery	Sherco 3 Depr Deferral	Rider: RES	Rider: TCR	ADIT Prorate for IRS	Cash Working Capital	Change in Cost of Capital	Net Operating Loss	
	Work Paper Reference						WP A-26	WP A-27	WP A-33	WP A-35	WP A-36	WP A-37	WP A-38	WP A-39	WP A-40	WP A-42	WP A-44	WP A-45	WP A-47	WP A-48	WP A-50	WP A-49	
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)
(1)																							
(2)	Plant as booked																						
(3)	Production	12,714,324				12,714,324											(469,868)						12,244,456
(4)	Transmission	3,660,697				3,660,697											(16,392)	(51,325)					3,592,979
(5)	Distribution	4,429,176				4,429,176												(57,846)					4,371,330
(6)	General	1,133,050				1,133,050												(80,427)					1,052,623
(7)	Common	990,884				990,884																	990,884
(8)	Total Utility Plant in Service	22,928,131				22,928,131											(486,260)	(189,598)					22,252,272
(9)																							
(10)	Reserve for Depreciation																						
(11)	Production	7,132,056				7,132,056	5,644										(18,349)						7,119,351
(12)	Transmission	836,919				836,919		(63)									(346)	(705)					835,805
(13)	Distribution	1,570,352				1,570,352		572										(1,217)					1,569,707
(14)	General	581,655				581,655		63										(8,896)					572,822
(15)	Common	466,910				466,910		1,915															468,825
(16)	Total Reserve for Depreciation	10,587,892				10,587,892	5,644	2,486									(18,695)	(10,818)					10,566,509
(17)																							
(18)	Net Utility Plant																						
(19)	Production	5,582,268				5,582,268	(5,644)										(451,519)						5,125,106
(20)	Transmission	2,823,778				2,823,778		63									(16,046)	(50,621)					2,757,174
(21)	Distribution	2,858,824				2,858,824		(572)										(56,629)					2,801,623
(22)	General	551,394				551,394		(63)										(71,531)					479,801
(23)	Common	523,974				523,974		(1,915)															522,059
(24)	Net Utility Plant in Service	12,340,239				12,340,239	(5,644)	(2,486)									(467,565)	(178,781)					11,685,763
(25)																							
(26)	Utility Plant Held for Future Use																						
(27)																							
(28)	Construction Work in Progress	419,734				419,734												(1,791)					417,943
(29)																							
(30)	Less: Accumulated Deferred Income Taxes	2,769,169	(10,844)		(632,260)	2,126,064	(1,586)	(699)	8,619						13,952	2,566	(38,757)	(5,346)	7,596			34,836	2,147,245
(31)																							
(32)	Other Rate Base Items																						
(33)	Cash Working Capital			(167,958)		(167,958)														14,245			(153,713)
(34)	Materials and Supplies	152,207				152,207																	152,207
(35)	Fuel Inventory	84,026				84,026																	84,026
(36)	Non Plant Assets and Liabilities	92,040				92,040			30,663														122,703
(37)	Customer Advances	(7,575)				(7,575)																	(7,575)
(38)	Customer Deposits	(44,786)				(44,786)																	(44,786)
(39)	Prepayments	71,706				71,706																	71,706
(40)	Regulatory Amortizations									709	373	3,000	255	41,972	34,128	6,289							86,726
(41)	Total Other Rate Base	347,618		(167,958)		179,660			30,663	709	373	3,000	255	41,972	34,128	6,289				14,245			311,294
(42)																							
(43)	Total Average Rate Base	10,338,422	10,844	(167,958)	632,260	10,813,568	(4,057)	(1,787)	22,044	709	373	3,000	255	41,972	20,177	3,723	(428,808)	(175,226)	(7,596)	14,245		(34,836)	10,267,755

Northern States Power Company

RATE BASE
RATE BASE ADJUSTMENT SCHEDULES
2023 Unadjusted Test Year versus Final Adjusted Test Year
($000's)

Line No.	NSPM - 11 Bridge by Report Label	Bridge - Unadjusted					Adjustments			Amortization									Secondary Calculations				Total
		Unadjusted w/o NOL & 199 at Last Authorized	ADIT Prorate for IRS	Cash Working Capital	Net Operating Loss	Total Unadjusted at Last Authorized	Depreciation Study: Remaining Life	Depreciation Study: TD&G	Pension: Extend Deferral	Aurora	Electric Vehicle	Income Tax Tracker	LED Street Lighting	NOL ADIT ARAM	PI EPU Recovery	Sherco 3 Depr Deferral	Rider: RES	Rider: TCR	ADIT Prorate for IRS	Cash Working Capital	Change in Cost of Capital	Net Operating Loss	Total
	Work Paper Reference						WP A-26	WP A-27	WP A-33	WP A-35	WP A-36	WP A-37	WP A-38	WP A-39	WP A-40	WP A-42	WP A-44	WP A-45	WP A-47	WP A-48	WP A-50	WP A-49	
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)
(1)																							
(2)	Plant as booked																						
(3)	Production	12,858,803				12,858,803											(467,309)						12,391,493
(4)	Transmission	3,813,127				3,813,127											(16,392)	(52,802)					3,743,932
(5)	Distribution	4,825,232				4,825,232												(151,466)					4,673,765
(6)	General	1,243,304				1,243,304												(113,907)					1,129,397
(7)	Common	1,128,391				1,128,391																	1,128,391
(8)	Total Utility Plant in Service	23,868,857				23,868,857											(483,702)	(318,176)					23,066,979
(9)																							
(10)	Reserve for Depreciation																						
(11)	Production	7,540,360				7,540,360	9,406										(38,655)						7,511,111
(12)	Transmission	900,976				900,976		(104)									(750)	(1,827)					898,294
(13)	Distribution	1,651,119				1,651,119		953										(4,321)					1,647,751
(14)	General	656,431				656,431		104										(20,407)					636,129
(15)	Common	548,755				548,755		3,191															551,946
(16)	Total Reserve for Depreciation	11,297,641				11,297,641	9,406	4,144									(39,405)	(26,555)					11,245,231
(17)																							
(18)	Net Utility Plant																						
(19)	Production	5,318,443				5,318,443	(9,406)										(428,655)						4,880,383
(20)	Transmission	2,912,151				2,912,151		104									(15,642)	(50,975)					2,845,638
(21)	Distribution	3,174,113				3,174,113		(953)										(147,146)					3,026,015
(22)	General	586,873				586,873		(104)										(93,501)					493,268
(23)	Common	579,636				579,636		(3,191)															576,445
(24)	Net Utility Plant in Service	12,571,216				12,571,216	(9,406)	(4,144)									(444,297)	(291,621)					11,821,748
(25)																							
(26)	Utility Plant Held for Future Use																						
(27)																							
(28)	Construction Work in Progress	538,152				538,152												(5,575)					532,577
(29)																							
(30)	Less: Accumulated Deferred Income Taxes	2,809,939	(2,928)		(789,232)	2,017,779	(2,644)	(1,165)	8,505						12,773	2,361	(68,076)	(10,979)	6,806			43,223	2,008,583
(31)																							
(32)	Other Rate Base Items																						
(33)	Cash Working Capital			(179,480)		(179,480)														14,978			(164,502)
(34)	Materials and Supplies	152,207				152,207																	152,207
(35)	Fuel Inventory	84,026				84,026																	84,026
(36)	Non Plant Assets and Liabilities	110,625				110,625			30,258														140,883
(37)	Customer Advances	(7,575)				(7,575)																	(7,575)
(38)	Customer Deposits	(44,786)				(44,786)																	(44,786)
(39)	Prepayments	72,297				72,297																	72,297
(40)	Regulatory Amortizations										124	1,000	85	39,703	31,244	5,786							77,943
(41)	Total Other Rate Base	366,794		(179,480)		187,315			30,258		124	1,000	85	39,703	31,244	5,786				14,978			310,493
(42)																							
(43)	Total Average Rate Base	10,666,223	2,928	(179,480)	789,232	11,278,903	(6,762)	(2,979)	21,752		124	1,000	85	39,703	18,472	3,425	(376,221)	(286,217)	(6,806)	14,978		(43,223)	10,656,235

INCOME SCHEDULE SCHEDULES
INCOME SCHEDULE ADJUSTMENT SCHEDULES
2021 Unadjusted Test Year versus Final Adjusted Test Year
($000's)

Line No.	NSPM - 11 Bridge by Report Label	Bridge - Unadjusted					Precedential	Adjustment							
		Unadjusted w/o NOL & 199	ADIT Prorate for IRS	Cash Working Capital	Net Operating Loss	Total Unadjusted at Last Authorized	Precedential Adjustments	CIP Approved Program Levels	CIP Incentive	Depreciation Study: Remaining Life	Depreciation Study: TD&G	Incentive Compensation	Pension: Deferred Amort	Pension: Extend Deferral	Transmission ROE
	Work Paper Reference						WP A-1 to A-23	WP A-24	WP A-25	WP A-26	WP A-27	WP A-28 to A-31	WP A-32	WP A-33	WP A-34
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
(1)															
(2)	Operating Revenues														
(3)	Retail Revenue	3,124,166				3,124,166		(9,920)							
(4)	Interdepartmental	456				456									
(5)	Other Operating	949,461				949,461	(285,840)		1,740	595	(7)				(14,289)
(6)	Total Revenue	4,074,083				4,074,083	(285,840)	(9,920)	1,740	595	(7)				(14,289)
(7)															
(8)	Expenses														
(9)	Operating Expenses														
(10)	Fuel & Purchased Energy	1,203,609				1,203,609	(271,335)								
(11)	Power Production	651,740				651,740	(559)					(3,818)			
(12)	Transmission	344,146				344,146									(2,390)
(13)	Distribution	130,998				130,998									
(14)	Customer Accounting	64,815				64,815									
(15)	Customer Service and Information	121,241				121,241		(9,920)	17,348						
(16)	Sales, Econ Dev, & Other	270				270	12								
(17)	Administrative and General	246,841				246,841	(11,110)					(10,344)			
(18)	Total Operating Expenses	2,763,660				2,763,660	(282,991)	(9,920)	17,348			(14,162)			(2,390)
(19)															
(20)	Depreciation	744,595				744,595				3,762	1,658				
(21)	Amortization	37,458				37,458							5,649		
(22)															
(23)	Taxes														
(24)	Property	192,908				192,908									
(25)	Deferred Income Tax and ITC	99,628			(181,273)	(81,645)				(1,058)	(466)			144	
(26)	Federal and State Income Tax	(270,676)	(208)	1,011	179,571	(90,301)	(809)		(4,486)	180	2	4,070	(1,624)	(290)	(3,420)
(27)	Payroll and Other	27,848				27,848	(33)								
(28)	Total Taxes	49,708	(208)	1,011	(1,702)	48,810	(842)		(4,486)	(878)	(464)	4,070	(1,624)	(145)	(3,420)
(29)															
(30)	Total Expenses	3,595,421	(208)	1,011	(1,702)	3,594,523	(283,834)	(9,920)	12,862	2,885	1,194	(10,092)	4,026	(145)	(5,810)
(31)															
(32)	Allowance for Funds Used During Construction	28,498				28,498									
(33)															
(34)	Net Income	507,159	208	(1,011)	1,702	508,057	(2,007)	(0)	(11,122)	(2,289)	(1,200)	10,092	(4,026)	145	(8,479)
(35)															
(36)	Calculation of Revenue Requirements														
(37)	Rate Base	10,155,903	32,141	(156,391)	306,400	10,338,053				(1,352)	(596)			21,945	
(38)	Required Operating Income	719,038	2,276	(11,072)	21,693	731,934				(96)	(42)			1,554	
(39)	Operating Income	507,159	208	(1,011)	1,702	508,057	(2,007)	(0)	(11,122)	(2,289)	(1,200)	10,092	(4,026)	145	(8,479)
(40)	Income Deficiency	211,879	2,068	(10,061)	19,991	223,877	2,007	0	11,122	2,194	1,158	(10,092)	4,026	1,409	8,479
(41)	**Revenue Deficiency**	**297,340**	**2,902**	**(14,119)**	**28,055**	**314,178**	**2,816**	**0**	**15,608**	**3,078**	**1,625**	**(14,162)**	**5,649**	**1,977**	**11,899**
(42)															
(43)	Calculation of Income Taxes														
(44)	Operating Revenue	4,074,083				4,074,083	(285,840)	(9,920)	1,740	595	(7)				(14,289)
(45)	-Operating Expense	2,763,660				2,763,660	(282,991)	(9,920)	17,348			(14,162)			(2,390)
(46)	-Amortization	37,458				37,458							5,649		
(47)	-Taxes Other then Income	320,384			(181,273)	139,111	(33)			(1,058)	(466)			144	
(48)	Operating Income Before Adjs	952,581			181,273	1,133,854	(2,816)	(0)	(15,608)	1,653	459	14,162	(5,649)	(144)	(11,899)
(49)	Additions to Income	256,247			(181,273)	74,974				(1,058)	(466)			144	
(50)	Deductions from Income	1,368,865			(78,466)	1,290,399								514	
(51)	Debt Synchonization	228,508		(3,519)	6,894	231,883				(30)	(13)			494	
(52)	State Taxable Income	(388,546)		3,519	71,572	(313,455)	(2,816)	(0)	(15,608)	626	7	14,162	(5,649)	(1,008)	(11,899)
(53)	State Income Tax Before Credits	(38,077)		345	7,014	(30,719)	(276)		(1,530)	61	1	1,388	(554)	(99)	(1,166)
(54)	State Tax Credits	(1,033)			1,033										
(55)	Federal Tax Deductions														
(56)	Federal Taxable Income	(349,436)		3,174	63,526	(282,736)	(2,540)	(0)	(14,078)	564	6	12,774	(5,096)	(909)	(10,733)
(57)	Federal Income Tax Before Credits	(73,381)		667	13,340	(59,375)	(533)		(2,956)	119	1	2,683	(1,070)	(191)	(2,254)
(58)	Federal Tax Credits	(158,184)			158,184										
(59)	Total Income Taxes	(270,676)		1,011	179,571	(90,093)	(809)		(4,486)	180	2	4,070	(1,624)	(290)	(3,420)

INCOME SCHEDULE SCHEDULES
INCOME SCHEDULE ADJUSTMENT SCHEDULES
2021 Unadjusted Test Year versus Final Adjusted Test Year
($000's)

Line No.	NSPM - 11 Bridge by Report Label	Amortization								Rider Removals				Secondary Calculations				Total	Fuel Adjustment	
		Aurora	Electric Vehicle	Income Tax Tracker	LED Street Lighting	NOL ADIT ARAM	PI EPU Recovery	Rate Case Expenses	Sherco 3 Depr Deferral	Renewable Connect	Rider: RES	Rider: TCR	Windsource	ADIT Prorate for IRS	Cash Working Capital	Change in Cost of Capital	Net Operating Loss		Remove FCA Revenue and Fuel Expense	Total Net of Fuel
	Work Paper Reference	WP A-35	WP A-36	WP A-37	WP A-38	WP A-39	WP A-40	WP A-41	WP A-42	WP A-43	WP A-44	WP A-45	WP A-46	WP A-47	WP A-48	WP A-50	WP A-49			
		(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)	(25)	(26)	(27)	(28)	(29)	(30)	(31)	(32)	(33)
(1)																				
(2)	Operating Revenues																			
(3)	Retail Revenue										(33,090)	(16,969)						3,064,187	(749,743)	2,314,444
(4)	Interdepartmental																	456		456
(5)	Other Operating						1,643					(100,161)	(7,516)					545,625		545,625
(6)	Total Revenue						1,643				(33,090)	(117,131)	(7,516)					3,610,268	(749,743)	2,860,525
(7)																				
(8)	Expenses																			
(9)	Operating Expenses																			
(10)	Fuel & Purchased Energy									(6,286)			(6,004)					919,984	(749,743)	170,241
(11)	Power Production									1,364	(3,963)		755					645,519		645,519
(12)	Transmission											(94,551)						247,205		247,205
(13)	Distribution											(3,624)						127,374		127,374
(14)	Customer Accounting											(6,077)						58,738		58,738
(15)	Customer Service and Information									(50)			(150)					128,469		128,469
(16)	Sales, Econ Dev, & Other																	282		282
(17)	Administrative and General																	225,387		225,387
(18)	Total Operating Expenses									(4,972)	(3,963)	(104,252)	(5,399)					2,352,958	(749,743)	1,603,215
(19)																				
(20)	Depreciation										(8,314)	(4,337)						737,364		737,364
(21)	Amortization	2,101	249	2,000	170	2,269	2,884	1,757	503									55,040		55,040
(22)																				
(23)	Taxes																			
(24)	Property										(931)	(47)						191,930		191,930
(25)	Deferred Income Tax and ITC						(1,179)		(205)		(23,348)	(2,144)					25,426	(84,474)		(84,474)
(26)	Federal and State Income Tax	(617)	(76)	(607)	(52)	(286)	331	(505)	(26)	1,429	31,410	325	(608)	86	(84)	7,436	(25,582)	(84,104)		(84,104)
(27)	Payroll and Other																	27,815		27,815
(28)	Total Taxes	(617)	(76)	(607)	(52)	(286)	(848)	(505)	(231)	1,429	7,130	(1,866)	(608)	86	(84)	7,436	(155)	51,167		51,167
(29)																				
(30)	Total Expenses	1,484	173	1,393	118	1,983	2,036	1,252	272	(3,543)	(5,147)	(110,454)	(6,008)	86	(84)	7,436	(155)	3,196,529	(749,743)	2,446,786
(31)																				
(32)	Allowance for Funds Used During Construction																	28,498		28,498
(33)																				
(34)	Net Income	(1,484)	(173)	(1,393)	(118)	(1,983)	(393)	(1,252)	(272)	3,543	(27,943)	(6,676)	(1,509)	(86)	84	(7,436)	155	442,237		442,237
(35)																				
(36)	Calculation of Revenue Requirements																			
(37)	Rate Base	2,079	622	5,001	425	44,240	21,882		4,021		(376,350)	(89,922)		(13,268)	13,064		(19,267)	9,950,576		9,950,576
(38)	Required Operating Income	147	44	354	30	3,132	1,549		285		(26,646)	(6,367)		(939)	925	26,867	(1,364)	731,367		731,367
(39)	Operating Income	(1,484)	(173)	(1,393)	(118)	(1,983)	(393)	(1,252)	(272)	3,543	(27,943)	(6,676)	(1,509)	(86)	84	(7,436)	155	442,237		442,237
(40)	Income Deficiency	1,631	217	1,747	148	5,115	1,942	1,252	557	(3,543)	1,297	310	1,509	(854)	840	34,303	(1,519)	289,131		289,131
(41)	**Revenue Deficiency**	**2,289**	**305**	**2,452**	**208**	**7,178**	**2,726**	**1,757**	**781**	**(4,972)**	**1,821**	**435**	**2,117**	**(1,198)**	**1,179**	**48,139**	**(2,132)**	**405,751**		**405,751**
(42)																				
(43)	Calculation of Income Taxes																			
(44)	Operating Revenue						1,643				(33,090)	(117,131)	(7,516)					3,610,268		3,610,268
(45)	-Operating Expense									(4,972)	(3,963)	(104,252)	(5,399)					2,352,958		2,352,958
(46)	-Amortization	2,101	249	2,000	170	2,269	2,884	1,757	503									55,040		55,040
(47)	-Taxes Other then Income						(1,179)		(205)		(24,279)	(2,191)					25,426	135,271		135,271
(48)	Operating Income Before Adjs	(2,101)	(249)	(2,000)	(170)	(2,269)	(62)	(1,757)	(298)	4,972	(4,848)	(10,688)	(2,117)				(25,426)	1,066,998		1,066,998
(49)	Additions to Income					2,269	1,705		298		(30,163)	(3,291)					25,426	69,839		69,839
(50)	Deductions from Income										(98,171)	(13,088)					78,466	1,258,120		1,258,120
(51)	Debt Synchonization	47	14	113	10	995	492		90		(8,468)	(2,023)		(299)	294	(25,871)	(434)	197,293		197,293
(52)	State Taxable Income	(2,148)	(263)	(2,113)	(179)	(995)	1,150	(1,757)	(90)	4,972	71,629	1,132	(2,117)	299	(294)	25,871	(78,033)	(318,576)		(318,576)
(53)	State Income Tax Before Credits	(211)	(26)	(207)	(18)	(98)	113	(172)	(9)	487	7,020	111	(207)	29	(29)	2,535	(7,647)	(31,220)		(31,220)
(54)	State Tax Credits										(34)						(1,033)	(1,067)		(1,067)
(55)	Federal Tax Deductions																			
(56)	Federal Taxable Income	(1,937)	(237)	(1,906)	(162)	(898)	1,038	(1,585)	(82)	4,485	64,643	1,021	(1,910)	269	(265)	23,336	(69,353)	(286,289)		(286,289)
(57)	Federal Income Tax Before Credits	(407)	(50)	(400)	(34)	(189)	218	(333)	(17)	942	13,575	214	(401)	57	(56)	4,901	(14,564)	(60,121)		(60,121)
(58)	Federal Tax Credits										10,849						(2,338)	8,512		8,512
(59)	Total Income Taxes	(617)	(76)	(607)	(52)	(286)	331	(505)	(26)	1,429	31,410	325	(608)	86	(84)	7,436	(25,582)	(83,896)		(83,896)

($000's)

Line No.	NSPM - 11 Bridge by Report Label	Bridge - Unadjusted					Precedential	Adjustment							
		Unadjusted w/o NOL & 199	ADIT Prorate for IRS	Cash Working Capital	Net Operating Loss	Total Unadjusted at Last Authorized	Precedential Adjustments	CIP Approved Program Levels	CIP Incentive	Depreciation Study: Remaining Life	Depreciation Study: TD&G	Incentive Compensation	Pension: Deferred Amort	Pension: Extend Deferral	Transmission ROE
	Work Paper Reference						WP A-1 to A-23	WP A-24	WP A-25	WP A-26	WP A-27	WP A-28 to A-31	WP A-32	WP A-33	WP A-34
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
(1)															
(2)	Operating Revenues														
(3)	Retail Revenue	3,149,734				3,149,734		(33,606)							
(4)	Interdepartmental	456				456									
(5)	Other Operating	972,502				972,502	(290,963)		3,014	554	(6)				(15,143)
(6)	Total Revenue	4,122,692				4,122,692	(290,963)	(33,606)	3,014	554	(6)				(15,143)
(7)															
(8)	Expenses														
(9)	Operating Expenses														
(10)	Fuel & Purchased Energy	1,203,463				1,203,463	(271,335)								
(11)	Power Production	655,726				655,726						(3,981)			
(12)	Transmission	356,664				356,664									(2,622)
(13)	Distribution	138,951				138,951									
(14)	Customer Accounting	63,683				63,683									
(15)	Customer Service and Information	145,946				145,946		(33,606)	16,380						
(16)	Sales, Econ Dev, & Other	272				272	12								
(17)	Administrative and General	257,169				257,169	(10,352)					(11,541)			
(18)	Total Operating Expenses	2,821,873				2,821,873	(281,675)	(33,606)	16,380			(15,521)			(2,622)
(19)															
(20)	Depreciation	805,099				805,099				3,762	1,658				
(21)	Amortization	33,994				33,994							5,649		
(22)															
(23)	Taxes														
(24)	Property	204,206				204,206									
(25)	Deferred Income Tax and ITC	61,237			(167,391)	(106,154)				(1,058)	(466)			(67)	
(26)	Federal and State Income Tax	(279,554)	(70)	1,086	162,933	(115,605)	(2,660)	0	(3,841)	185	10	4,461	(1,624)	(74)	(3,599)
(27)	Payroll and Other	28,100				28,100	(33)								
(28)	Total Taxes	13,989	(70)	1,086	(4,458)	10,547	(2,693)	0	(3,841)	(872)	(456)	4,461	(1,624)	(141)	(3,599)
(29)															
(30)	Total Expenses	3,674,955	(70)	1,086	(4,458)	3,671,513	(284,368)	(33,606)	12,538	2,890	1,201	(11,060)	4,026	(141)	(6,221)
(31)															
(32)	Allowance for Funds Used During Construction	25,065				25,065									
(33)															
(34)	Net Income	472,802	70	(1,086)	4,458	476,243	(6,595)	0	(9,524)	(2,337)	(1,208)	11,060	(4,026)	141	(8,922)
(35)															
(36)	Calculation of Revenue Requirements														
(37)	Rate Base	10,338,422	10,844	(167,958)	632,260	10,813,568				(4,057)	(1,787)			22,044	
(38)	Required Operating Income	731,960	768	(11,891)	44,764	765,601				(287)	(127)			1,561	
(39)	Operating Income	472,802	70	(1,086)	4,458	476,243	(6,595)	0	(9,524)	(2,337)	(1,208)	11,060	(4,026)	141	(8,922)
(40)	Income Deficiency	259,159	698	(10,805)	40,306	289,357	6,595	(0)	9,524	2,049	1,081	(11,060)	4,026	1,420	8,922
(41)	**Revenue Deficiency**	**363,691**	**979**	**(15,164)**	**56,564**	**406,070**	**9,255**	**(0)**	**13,365**	**2,876**	**1,517**	**(15,521)**	**5,649**	**1,992**	**12,521**
(42)															
(43)	Calculation of Income Taxes														
(44)	Operating Revenue	4,122,692				4,122,692	(290,963)	(33,606)	3,014	554	(6)				(15,143)
(45)	-Operating Expense	2,821,873				2,821,873	(281,675)	(33,606)	16,380			(15,521)			(2,622)
(46)	-Amortization	33,994				33,994							5,649		
(47)	-Taxes Other then Income	293,543			(167,391)	126,152	(33)			(1,058)	(466)			(67)	
(48)	Operating Income Before Adjs	973,282			167,391	1,140,672	(9,255)	0	(13,365)	1,611	460	15,521	(5,649)	67	(12,521)
(49)	Additions to Income	214,093			(167,391)	46,703				(1,058)	(466)			(67)	
(50)	Deductions from Income	1,273,080			61,647	1,334,728								(239)	
(51)	Debt Synchonization	232,614	244	(3,779)	14,226	243,305				(91)	(40)			496	
(52)	State Taxable Income	(318,320)	(244)	3,779	(75,873)	(390,658)	(9,255)	0	(13,365)	645	34	15,521	(5,649)	(257)	(12,521)
(53)	State Income Tax Before Credits	(31,195)	(24)	370	(7,436)	(38,284)	(907)	0	(1,310)	63	3	1,521	(554)	(25)	(1,227)
(54)	State Tax Credits	(1,033)			(100)	(1,133)									
(55)	Federal Tax Deductions														
(56)	Federal Taxable Income	(286,092)	(220)	3,409	(68,338)	(351,241)	(8,348)	0	(12,056)	582	31	14,000	(5,096)	(231)	(11,294)
(57)	Federal Income Tax Before Credits	(60,079)	(46)	716	(14,351)	(73,761)	(1,753)	0	(2,532)	122	6	2,940	(1,070)	(49)	(2,372)
(58)	Federal Tax Credits	(187,247)			184,819	(2,427)									
(59)	Total Income Taxes	(279,554)	(70)	1,086	162,933	(115,605)	(2,660)	0	(3,841)	185	10	4,461	(1,624)	(74)	(3,599)

INCOME SCHEDULE ADJUSTMENT SCHEDULES
2022 Unadjusted Test Year versus Final Adjusted Test Year
($000's)

Line No.	NSPM - 11 Bridge by Report Label	Amortization								Rider Removals				Secondary Calculations				Total	Fuel Adjustment	
		Aurora	Electric Vehicle	Income Tax Tracker	LED Street Lighting	NOL ADIT ARAM	PI EPU Recovery	Rate Case Expenses	Sherco 3 Depr Deferral	Renewable Connect	Rider: RES	Rider: TCR	Windsource	ADIT Prorate for IRS	Cash Working Capital	Change in Cost of Capital	Net Operating Loss		Remove FCA Revenue and Fuel Expense	Total Net of Fuel
	Work Paper Reference	WP A-35	WP A-36	WP A-37	WP A-38	WP A-39	WP A-40	WP A-41	WP A-42	WP A-43	WP A-44	WP A-45	WP A-46	WP A-47	WP A-48	WP A-50	WP A-49			
		(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)	(25)	(26)	(27)	(28)	(29)	(30)	(31)	(32)	(33)
(1)																				
(2)	Operating Revenues																			
(3)	Retail Revenue										(22,677)	(40,073)						3,053,378	(749,743)	2,303,635
(4)	Interdepartmental																	456		456
(5)	Other Operating						1,514					(100,818)	(7,516)					563,138		563,138
(6)	Total Revenue						1,514				(22,677)	(140,891)	(7,516)					3,616,972	(749,743)	2,867,229
(7)																				
(8)	Expenses																			
(9)	Operating Expenses																			
(10)	Fuel & Purchased Energy									(6,286)			(6,004)					919,838	(749,743)	170,095
(11)	Power Production									4,932	(8,820)							647,857		647,857
(12)	Transmission											(94,931)						259,111		259,111
(13)	Distribution											(6,014)						132,937		132,937
(14)	Customer Accounting											(11,282)						52,401		52,401
(15)	Customer Service and Information									(150)			(25)					128,545		128,545
(16)	Sales, Econ Dev, & Other																	284		284
(17)	Administrative and General																	235,276		235,276
(18)	Total Operating Expenses									(1,504)	(8,820)	(112,228)	(6,029)					2,376,248	(749,743)	1,626,505
(19)																				
(20)	Depreciation										(20,733)	(11,414)						778,372		778,372
(21)	Amortization	2,101	249	2,000	170	2,269	2,884	1,757	503									51,576		51,576
(22)																				
(23)	Taxes																			
(24)	Property										(2,067)	(751)						201,387		201,387
(25)	Deferred Income Tax and ITC						(1,179)		(205)		(38,113)	(5,256)					5,710	(146,787)		(146,787)
(26)	Federal and State Income Tax	(609)	(74)	(594)	(50)	(271)	305	(505)	(24)	432	78,863	1,755	(427)	49	(92)	7,968	(5,116)	(41,137)		(41,137)
(27)	Payroll and Other																	28,067		28,067
(28)	Total Taxes	(609)	(74)	(594)	(50)	(271)	(874)	(505)	(229)	432	38,683	(4,252)	(427)	49	(92)	7,968	594	41,530		41,530
(29)																				
(30)	Total Expenses	1,493	175	1,406	119	1,997	2,010	1,252	274	(1,072)	9,130	(127,893)	(6,456)	49	(92)	7,968	594	3,247,727	(749,743)	2,497,984
(31)																				
(32)	Allowance for Funds Used During Construction																	25,065		25,065
(33)																				
(34)	Net Income	(1,493)	(175)	(1,406)	(119)	(1,997)	(495)	(1,252)	(274)	1,072	(31,807)	(12,998)	(1,060)	(49)	92	(7,968)	(594)	394,311		394,311
(35)																				
(36)	Calculation of Revenue Requirements																			
(37)	Rate Base	709	373	3,000	255	41,972	20,177		3,723		(428,808)	(175,226)		(7,596)	14,245		(34,836)	10,267,755		10,267,755
(38)	Required Operating Income	50	26	212	18	2,972	1,429		264		(30,360)	(12,406)		(538)	1,009	26,696	(2,466)	753,653		753,653
(39)	Operating Income	(1,493)	(175)	(1,406)	(119)	(1,997)	(495)	(1,252)	(274)	1,072	(31,807)	(12,998)	(1,060)	(49)	92	(7,968)	(594)	394,311		394,311
(40)	Income Deficiency	1,543	201	1,618	137	4,969	1,924	1,252	537	(1,072)	1,448	592	1,060	(489)	916	34,664	(1,872)	359,343		359,343
(41)	**Revenue Deficiency**	**2,165**	**282**	**2,271**	**193**	**6,973**	**2,700**	**1,757**	**754**	**(1,504)**	**2,032**	**830**	**1,487**	**(686)**	**1,286**	**48,646**	**(2,627)**	**504,284**		**504,284**
(42)																				
(43)	Calculation of Income Taxes																			
(44)	Operating Revenue						1,514				(22,677)	(140,891)	(7,516)					3,616,972		3,616,972
(45)	-Operating Expense									(1,504)	(8,820)	(112,228)	(6,029)					2,376,248		2,376,248
(46)	-Amortization	2,101	249	2,000	170	2,269	2,884	1,757	503									51,576		51,576
(47)	-Taxes Other then Income						(1,179)		(205)		(40,180)	(6,006)					5,710	82,667		82,667
(48)	Operating Income Before Adjs	(2,101)	(249)	(2,000)	(170)	(2,269)	(191)	(1,757)	(298)	1,504	26,323	(22,657)	(1,487)				(5,710)	1,106,481		1,106,481
(49)	Additions to Income					2,269	1,705		298		(38,113)	(5,517)					5,710	11,464		11,464
(50)	Deductions from Income										(156,301)	(30,337)					(61,647)	1,086,202		1,086,202
(51)	Debt Synchonization	16	8	68	6	944	454		84		(9,648)	(3,943)		(171)	321	(27,723)	(784)	203,302		203,302
(52)	State Taxable Income	(2,117)	(257)	(2,068)	(176)	(944)	1,060	(1,757)	(84)	1,504	154,160	6,106	(1,487)	171	(321)	27,723	62,431	(171,560)		(171,560)
(53)	State Income Tax Before Credits	(207)	(25)	(203)	(17)	(93)	104	(172)	(8)	147	15,108	598	(146)	17	(31)	2,717	6,118	(16,813)		(16,813)
(54)	State Tax Credits										(440)						100	(1,473)		(1,473)
(55)	Federal Tax Deductions																			
(56)	Federal Taxable Income	(1,910)	(232)	(1,865)	(158)	(852)	957	(1,585)	(76)	1,357	139,492	5,507	(1,342)	154	(289)	25,006	56,213	(153,274)		(153,274)
(57)	Federal Income Tax Before Credits	(401)	(49)	(392)	(33)	(179)	201	(333)	(16)	285	29,293	1,157	(282)	32	(61)	5,251	11,805	(32,188)		(32,188)
(58)	Federal Tax Credits										34,902						(23,139)	9,336		9,336
(59)	Total Income Taxes	(609)	(74)	(594)	(50)	(271)	305	(505)	(24)	432	78,863	1,755	(427)	49	(92)	7,968	(5,116)	(41,137)		(41,137)

INCOME SCHEDULE ADJUSTMENT SCHEDULES
2023 Unadjusted Test Year versus Final Adjusted Test Year
($000's)

		Bridge - Unadjusted					Precedential	Adjustment							
Line No.	NSPM - 11 Bridge by Report Label	Unadjusted w/o NOL & 199	ADIT Prorate for IRS	Cash Working Capital	Net Operating Loss	Total Unadjusted at Last Authorized	Precedential Adjustments	CIP Approved Program Levels	CIP Incentive	Depreciation Study: Remaining Life	Depreciation Study: TD&G	Incentive Compensation	Pension: Deferred Amort	Pension: Extend Deferral	Transmission ROE
	Work Paper Reference						WP A-1 to A-23	WP A-24	WP A-25	WP A-26	WP A-27	WP A-28 to A-31	WP A-32	WP A-33	WP A-34
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
(1)															
(2)	Operating Revenues														
(3)	Retail Revenue	3,154,068				3,154,068		(45,110)							
(4)	Interdepartmental	456				456									
(5)	Other Operating	980,618				980,618	(292,095)		418	512	(6)				(14,997)
(6)	Total Revenue	4,135,142				4,135,142	(292,095)	(45,110)	418	512	(6)				(14,997)
(7)															
(8)	Expenses														
(9)	Operating Expenses														
(10)	Fuel & Purchased Energy	1,203,944				1,203,944	(271,335)								
(11)	Power Production	675,178				675,178						(4,091)			
(12)	Transmission	362,822				362,822									(2,537)
(13)	Distribution	140,577				140,577									
(14)	Customer Accounting	55,288				55,288									
(15)	Customer Service and Information	158,842				158,842		(45,110)	15,034						
(16)	Sales, Econ Dev, & Other	271				271	12								
(17)	Administrative and General	260,943				260,943	(9,947)					(12,380)			
(18)	Total Operating Expenses	2,857,865				2,857,865	(281,270)	(45,110)	15,034			(16,471)			(2,537)
(19)															
(20)	Depreciation	828,155				828,155				3,762	1,658				
(21)	Amortization	33,986				33,986							5,649		
(22)															
(23)	Taxes														
(24)	Property	216,712				216,712									
(25)	Deferred Income Tax and ITC	17,863			(146,553)	(128,691)				(1,058)	(466)			(160)	
(26)	Federal and State Income Tax	(254,710)	(19)	1,161	141,539	(112,030)	(3,102)	(0)	(4,201)	191	18	4,734	(1,624)	23	(3,581)
(27)	Payroll and Other	28,342				28,342	(34)								
(28)	Total Taxes	8,206	(19)	1,161	(5,015)	4,333	(3,136)	(0)	(4,201)	(867)	(448)	4,734	(1,624)	(137)	(3,581)
(29)															
(30)	Total Expenses	3,728,213	(19)	1,161	(5,015)	3,724,340	(284,405)	(45,110)	10,833	2,896	1,209	(11,737)	4,026	(137)	(6,118)
(31)															
(32)	Allowance for Funds Used During Construction	31,124				31,124									
(33)															
(34)	Net Income	438,053	19	(1,161)	5,015	441,926	(7,690)	(0)	(10,415)	(2,384)	(1,215)	11,737	(4,026)	137	(8,879)
(35)															
(36)	Calculation of Revenue Requirements														
(37)	Rate Base	10,666,223	2,928	(179,480)	789,232	11,278,903				(6,762)	(2,979)			21,752	
(38)	Required Operating Income	755,169	207	(12,707)	55,878	798,546				(479)	(211)			1,540	
(39)	Operating Income	438,053	19	(1,161)	5,015	441,926	(7,690)	(0)	(10,415)	(2,384)	(1,215)	11,737	(4,026)	137	(8,879)
(40)	Income Deficiency	317,116	188	(11,546)	50,863	356,621	7,690	0	10,415	1,905	1,004	(11,737)	4,026	1,403	8,879
(41)	**Revenue Deficiency**	**445,025**	**264**	**(16,204)**	**71,379**	**500,464**	**10,791**	**0**	**14,616**	**2,673**	**1,409**	**(16,471)**	**5,649**	**1,969**	**12,460**
(42)															
(43)	Calculation of Income Taxes														
(44)	Operating Revenue	4,135,142				4,135,142	(292,095)	(45,110)	418	512	(6)				(14,997)
(45)	-Operating Expense	2,857,865				2,857,865	(281,270)	(45,110)	15,034			(16,471)			(2,537)
(46)	-Amortization	33,986				33,986							5,649		
(47)	-Taxes Other then Income	262,916			(146,553)	116,363	(34)			(1,058)	(466)			(160)	
(48)	Operating Income Before Adjs	980,374			146,553	1,126,928	(10,791)	(0)	(14,616)	1,570	460	16,471	(5,649)	160	(12,460)
(49)	Additions to Income	170,890			(146,553)	24,337				(1,058)	(466)			(160)	
(50)	Deductions from Income	1,143,137			16,819	1,159,956								(571)	
(51)	Debt Synchonization	239,990	66	(4,038)	17,758	253,775				(152)	(67)			489	
(52)	State Taxable Income	(231,862)	(66)	4,038	(34,577)	(262,467)	(10,791)	(0)	(14,616)	664	61	16,471	(5,649)	81	(12,460)
(53)	State Income Tax Before Credits	(22,722)	(6)	396	(3,389)	(25,722)	(1,058)	(0)	(1,432)	65	6	1,614	(554)	8	(1,221)
(54)	State Tax Credits	(1,033)			(933)	(1,965)									
(55)	Federal Tax Deductions														
(56)	Federal Taxable Income	(208,107)	(59)	3,643	(30,256)	(234,780)	(9,734)	(0)	(13,184)	599	55	14,857	(5,096)	73	(11,239)
(57)	Federal Income Tax Before Credits	(43,702)	(12)	765	(6,354)	(49,304)	(2,044)	(0)	(2,769)	126	12	3,120	(1,070)	15	(2,360)
(58)	Federal Tax Credits	(187,253)			152,214	(35,039)									
(59)	Total Income Taxes	(254,710)	(19)	1,161	141,539	(112,030)	(3,102)	(0)	(4,201)	191	18	4,734	(1,624)	23	(3,581)

INCOME SCHEDULE ADJUSTMENT SCHEDULES
2023 Unadjusted Test Year versus Final Adjusted Test Year
($000's)

Line No.	NSPM - 11 Bridge by Report Label	Amortization								Rider Removals				Secondary Calculations					Fuel Adjustment	
		Aurora	Electric Vehicle	Income Tax Tracker	LED Street Lighting	NOL ADIT ARAM	PI EPU Recovery	Rate Case Expenses	Sherco 3 Depr Deferral	Renewable Connect	Rider: RES	Rider: TCR	Windsource	ADIT Prorate for IRS	Cash Working Capital	Change in Cost of Capital	Net Operating Loss	Total	Remove FCA Revenue and Fuel Expense	Total Net of Fuel
	Work Paper Reference	WP A-35	WP A-36	WP A-37	WP A-38	WP A-39	WP A-40	WP A-41	WP A-42	WP A-43	WP A-44	WP A-45	WP A-46	WP A-47	WP A-48	WP A-50	WP A-49			
		(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)	(25)	(26)	(27)	(28)	(29)	(30)	(31)	(32)	(33)
(1)																				
(2)	Operating Revenues																			
(3)	Retail Revenue										(17,897)	(60,154)						3,030,907	(749,743)	2,281,164
(4)	Interdepartmental																	456		456
(5)	Other Operating						1,386					(99,851)	(7,516)					568,469		568,469
(6)	Total Revenue						1,386				(17,897)	(160,005)	(7,516)					3,599,831	(749,743)	2,850,088
(7)																				
(8)	Expenses																			
(9)	Operating Expenses																			
(10)	Fuel & Purchased Energy									(6,286)			(6,004)					920,319	(749,743)	170,576
(11)	Power Production									5,057	(8,309)							667,835		667,835
(12)	Transmission											(93,774)						266,511		266,511
(13)	Distribution											(4,922)						135,655		135,655
(14)	Customer Accounting											(13,462)						41,826		41,826
(15)	Customer Service and Information									(150)								128,615		128,615
(16)	Sales, Econ Dev, & Other																	283		283
(17)	Administrative and General																	238,616		238,616
(18)	Total Operating Expenses									(1,379)	(8,309)	(112,158)	(6,004)					2,399,661	(749,743)	1,649,918
(19)																				
(20)	Depreciation										(20,686)	(20,060)						792,829		792,829
(21)	Amortization		249	2,000	170	2,269	2,884	1,757	503									49,467		49,467
(22)																				
(23)	Taxes																			
(24)	Property										(2,069)	(795)						213,848		213,848
(25)	Deferred Income Tax and ITC						(1,179)		(205)		(20,398)	(6,021)					11,064	(147,115)		(147,115)
(26)	Federal and State Income Tax		(72)	(581)	(49)	(257)	279	(505)	(22)	396	61,446	240	(435)	44	(97)	8,576	(10,874)	(61,483)		(61,483)
(27)	Payroll and Other																	28,308		28,308
(28)	Total Taxes		(72)	(581)	(49)	(257)	(900)	(505)	(227)	396	38,979	(6,577)	(435)	44	(97)	8,576	190	33,558		33,558
(29)																				
(30)	Total Expenses		176	1,419	120	2,012	1,984	1,252	276	(982)	9,983	(138,795)	(6,439)	44	(97)	8,576	190	3,275,515	(749,743)	2,525,772
(31)																				
(32)	Allowance for Funds Used During Construction																	31,124		31,124
(33)																				
(34)	Net Income		(176)	(1,419)	(120)	(2,012)	(598)	(1,252)	(276)	982	(27,880)	(21,210)	(1,078)	(44)	97	(8,576)	(190)	355,440		355,440
(35)																				
(36)	Calculation of Revenue Requirements																			
(37)	Rate Base		124	1,000	85	39,703	18,472		3,425		(376,221)	(286,217)		(6,806)	14,978	26,641	(43,223)	10,656,235		10,656,235
(38)	Required Operating Income		9	71	6	2,811	1,308		242		(26,636)	(20,264)		(482)	1,060		(3,060)	781,102		781,102
(39)	Operating Income		(176)	(1,419)	(120)	(2,012)	(598)	(1,252)	(276)	982	(27,880)	(21,210)	(1,078)	(44)	97	(8,576)	(190)	355,438		355,438
(40)	Income Deficiency		185	1,490	126	4,823	1,906	1,252	518	(982)	1,243	946	1,078	(438)	964	35,216	(2,870)	425,664		425,664
(41)	**Revenue Deficiency**		**260**	**2,091**	**177**	**6,768**	**2,674**	**1,757**	**727**	**(1,379)**	**1,745**	**1,327**	**1,512**	**(614)**	**1,352**	**49,421**	**(4,028)**	**597,356**		**597,356**
(42)																				
(43)	Calculation of Income Taxes																			
(44)	Operating Revenue						1,386				(17,897)	(160,005)	(7,516)					3,599,831		3,599,831
(45)	-Operating Expense									(1,379)	(8,309)	(112,158)	(6,004)					2,399,661		2,399,661
(46)	-Amortization		249	2,000	170	2,269	2,884	1,757	503									49,467		49,467
(47)	-Taxes Other then Income						(1,179)		(205)		(22,467)	(6,817)					11,064	95,041		95,041
(48)	Operating Income Before Adjs		(249)	(2,000)	(170)	(2,269)	(319)	(1,757)	(298)	1,379	12,880	(41,030)	(1,512)				(11,064)	1,055,662		1,055,662
(49)	Additions to Income					2,269	1,705		298		(20,398)	(6,144)					11,064	11,446		11,446
(50)	Deductions from Income										(93,234)	(41,569)					(16,819)	1,007,763		1,007,763
(51)	Debt Synchonization		3	23	2	893	416		77		(8,465)	(6,440)		(153)	337	(29,837)	(973)	209,928		209,928
(52)	State Taxable Income		(252)	(2,023)	(172)	(893)	971	(1,757)	(77)	1,379	94,180	834	(1,512)	153	(337)	29,837	17,792	(150,583)		(150,583)
(53)	State Income Tax Before Credits		(25)	(198)	(17)	(88)	95	(172)	(8)	135	9,230	82	(148)	15	(33)	2,924	1,744	(14,757)		(14,757)
(54)	State Tax Credits										(669)						933	(1,701)		(1,701)
(55)	Federal Tax Deductions																			
(56)	Federal Taxable Income		(227)	(1,825)	(155)	(806)	875	(1,585)	(70)	1,244	85,619	752	(1,364)	138	(304)	26,913	15,115	(134,125)		(134,125)
(57)	Federal Income Tax Before Credits		(48)	(383)	(33)	(169)	184	(333)	(15)	261	17,980	158	(286)	29	(64)	5,652	3,174	(28,166)		(28,166)
(58)	Federal Tax Credits										34,904						(16,724)	(16,858)		(16,858)
(59)	Total Income Taxes		(72)	(581)	(49)	(257)	279	(505)	(22)	396	61,446	240	(435)	44	(97)	8,576	(10,874)	(61,483)		(61,483)

2021-2023 MYRP ADJUSTMENT SUMMARY

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Line No.	Record Category	Report Label	Record Type	MN Electric			Workpaper Reference
				2021 Test Year	2022 Plan Year	2023 Plan Year	
1	Unadjusted	Unadjusted	**Total Unadjusted**	**366,372,149**	**461,757,713**	**558,875,591**	
2							
3	Precedential	Precedential Adjustments	NSPM-Advertising (Trad)	(3,090,791)	(3,121,652)	(3,152,821)	WP-A1
4	Precedential	Precedential Adjustments	NSPM-Assn Dues (Trad)	(288,989)	(286,758)	(286,037)	WP-A2
5	Precedential	Precedential Adjustments	NSPM-Aviation	(2,792,391)	(2,151,518)	(2,579,061)	WP-A3
6	Precedential	Precedential Adjustments	NSPM-Chamber of Commerce Dues	184,812	184,812	184,812	WP-A4
7	Precedential	Precedential Adjustments	NSPM-Customer Deposits - A&G Expense (Trad)	22,560	22,560	22,560	WP-A5
8	Precedential	Precedential Adjustments	NSPM-Donations (Trad)	615,749	616,933	1,428,788	WP-A6
9	Precedential	Precedential Adjustments	NSPM-Econ Dev Donations (Trad)	94,157	94,157	94,157	WP-A7
10	Precedential	Precedential Adjustments	NSPM-Econ Develop (Trad)	(81,725)	(81,725)	(81,725)	WP-A8
11	Precedential	Precedential Adjustments	NSPM-Employee Expenses	(1,569,250)	(1,512,319)	(1,562,482)	WP-A9
12	Precedential	Precedential Adjustments	NSPM-Foundation Admin	(31,280)	(31,923)	(32,884)	WP-A10
13	Precedential	Precedential Adjustments	NSPM-Investor Relations	(307,739)	(312,377)	(317,246)	WP-A11
14	Precedential	Precedential Adjustments	NSPM-Monticello EPU Commission Order No Return	(10,349,841)	(9,106,974)	(7,867,132)	WP-A12
15	Precedential	Precedential Adjustments	NSPM-Nobles Disallowed Assets	(173,156)	(159,101)	(145,076)	WP-A13
16	Precedential	Precedential Adjustments	NSPM-Nuclear Retention Removal	(558,680)			WP-A14
17	Precedential	Precedential Adjustments	NSPM-Other Revenue to 3 Year Average Adj	(1,813,527)	(1,588,690)	(783,097)	WP-A15
18	Precedential	Precedential Adjustments	NSPM-Pension Discount Rate Int	(173,201)	(174,077)	(175,015)	WP-A16
19	Precedential	Precedential Adjustments	NSPM-Pension Non-Qual Restoration Removal	(635,826)	(629,083)	(619,290)	WP-A17
20	Precedential	Precedential Adjustments	NSPM-Pension Non-Qual SERP Removal	(241,513)	(165,398)	(124,179)	WP-A18
21	Precedential	Precedential Adjustments	NSPM-Pension Retiree Medical	(248,435)	(217,659)	(190,088)	WP-A19
22	Precedential	Precedential Adjustments	NSPM-Pension Tracker Difference	9,177	(49,670)	(18,648)	WP-A20
23	Precedential	Precedential Adjustments	NSPM-Remove Asset Trading	18,954,169	18,954,169	18,954,169	WP-A21
24	Precedential	Precedential Adjustments	NSPM-Remove NonAsset Trading	7,887,154	11,528,276	10,600,837	WP-A22
25	Precedential	Precedential Adjustments	NSPM-Remove NonAsset Trading Fully Allocated Costs	(2,595,578)	(2,557,083)	(2,559,136)	WP-A23
26	Precedential		**Sub-Total Precedential**	**2,815,856**	**9,254,901**	**10,791,408**	
27							
28	Adjustment	CIP Approved Program Levels	NSPM-CIP Revenue and Expense Elimination	0	(1)		WP-A24
29	Adjustment	CIP Incentive	NSPM-CIP Incentive - Retain Shareholder Portion	15,607,747	13,365,327	14,616,185	WP-A25
30	Adjustment	Depreciation Study: Remaining Life	NSPM-Remaining Life	3,071,913	2,856,734	2,642,008	WP-A26
31	Adjustment	Depreciation Study: TD&G	NSPM-MN Depreciation Study TD&G	1,622,142	1,508,516	1,395,128	WP-A27
32	Adjustment	Incentive Compensation	NSPM-Incentive Pay	(1,827,992)	(1,882,829)	(1,939,315)	WP-A28
33	Adjustment	Incentive Compensation	NSPM-Incentive Pay_Environmental LTI	2,132,800	2,208,401	2,216,499	WP-A29
34	Adjustment	Incentive Compensation	NSPM-Incentive Pay_Remove Long Term	(15,801,256)	(17,274,734)	(18,225,624)	WP-A30
35	Adjustment	Incentive Compensation	NSPM-Incentive Pay_Time Based LTI	1,334,455	1,427,772	1,477,665	WP-A31
36	Adjustment	Pension: Deferred Amort	NSPM-Pension Deferred Amortization	5,649,338	5,649,338	5,649,338	WP-A32
37	Adjustment	Pension: Extend Deferral	NSPM-MN Electric Pension Extend Deferral	2,082,843	2,096,710	2,069,805	WP-A33
38	Adjustment	Transmission ROE	NSPM-Transmission ROE Change	11,898,769	12,520,825	12,460,063	WP-A34
39	Adjustment		**Sub-Total Adjustment**	**25,770,759**	**22,476,060**	**22,361,751**	
40							
41	Amortization	Aurora	NSPM-Aurora Deferral	2,298,981	2,168,531		WP-A35
42	Amortization	Electric Vehicle	NSPM-Electric Vehicle Tariff Deferral	307,943	284,242	260,590	WP-A36
43	Amortization	Income Tax Tracker	NSPM-MN Electric Income Tax Tracker Amortization	2,475,891	2,285,329	2,095,168	WP-A37
44	Amortization	LED Street Lighting	NSPM-Settlement LED Street Lighting	210,187	194,010	177,866	WP-A38
45	Amortization	NOL ADIT ARAM	NSPM-NOL Tax Reform ADIT ARAM	7,391,966	7,171,967	6,952,422	WP-A39
46	Amortization	PI EPU Recovery	NSPM-PI EPU Deferral	2,831,514	2,795,566	2,759,958	WP-A40
47	Amortization	Rate Case Expenses	NSPM-Amortization Rate Case Expense	1,756,978	1,756,978	1,756,978	WP-A41
48	Amortization	Sherco 3 Depr Deferral	NSPM-Sherco 3 Deferral	800,430	771,727	743,084	WP-A42
49	Amortization		**Sub-Total Amortization**	**18,073,890**	**17,428,350**	**14,746,066**	
50							
51	Rider Removals	Renewable Connect	NSPM-Remove Renewable Connect	(4,971,943)	(1,504,382)	(1,378,688)	WP-A43
52	Rider Removals	Rider: RES	NSPM-RES Rider Removal	0	0	0	WP-A44
53	Rider Removals	Rider: TCR	NSPM-TCR-MN Rider Removal	0	(0)	(0)	WP-A45
54	Rider Removals	Windsource	NSPM-Remove Windsource	2,116,992	1,487,366	1,512,366	WP-A46
55	Rider Removals		**Sub-Total Rider Removals**	**(2,854,951)**	**(17,015)**	**133,678**	
56							
57	Secondary Calculations	ADIT Prorate for IRS	NSPM-ADIT Prorate for IRS	1,795,168	308,638	(368,145)	WP-A47
58	Secondary Calculations	Cash Working Capital	NSPM-Cash Working Capital	(13,633,125)	(14,605,729)	(15,614,414)	WP-A48
59	Secondary Calculations	Net Operating Loss	NSPM-NOL/Credits/199	7,412,031	7,681,402	6,430,315	WP-A49
60	Secondary Calculations		**Sub-Total Secondary Calculations**	**(4,425,927)**	**(6,615,688)**	**(9,552,245)**	
61							
62			Total Revenue Deficiency	405,751,777	504,284,320	597,356,250	

Note: Adjustment amounts in Schedule 12 reflect the revenue requirement calculated at the capital structure proposed in this rate case. See Workpaper A50 for the adjustment due to change in COC.

Northern States Power Company
PRECEDENTIAL ADJUSTMENT DETAIL SCHEDULE
2021 Test Year
($000's)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)	(25)	(26)
		Precedential																							
Line No.	NSPM - 11 Bridge by Report Label	NSPM-Advertising (Trad)	NSPM-Assn Dues (Trad)	NSPM-Aviation	NSPM-Chamber of Commerce Dues	NSPM-Customer Deposits - A&G Expense (Trad)	NSPM-Donations (Trad)	NSPM-Econ Dev Donations (Trad)	NSPM-Econ Develop (Trad)	NSPM-Employee Expenses	NSPM-Foundation Admin	NSPM-Investor Relations	NSPM-Monticello EPU Commission Order No Return	NSPM-Nobles Disallowed Assets	NSPM-Nuclear Retention Removal	NSPM-Other Revenue to 3 Year Average Adj	NSPM-Pension Discount Rate Int	NSPM-Pension Non-Qual Restoration Removal	NSPM-Pension Non-Qual SERP Removal	NSPM-Pension Retiree Medical	NSPM-Pension Tracker Difference	NSPM-Remove Asset Trading	NSPM-Remove NonAsset Trading	NSPM-Remove NonAsset Trading Fully Allocated Costs	Total
1																									
2	Operating Revenues																								
3	Retail Revenue																								
4	Other Operating												10,350	173		1,814						(136,873)	(161,304)		(285,840)
5	Total Revenue												10,350	173		1,814						(136,873)	(161,304)		(285,840)
6																									
7	Expenses																								
8	Operating Expenses																								
9	Power Production without regional mkts														(559)										(559)
10	Fuel & Purchased Energy																					(117,919)	(153,417)		(271,335)
11	Power Production														(559)										(559)
12	Transmission																								
13	Customer Accounting																								
14	Customer Service and Information																								
15	Sales, Econ Dev, & Other							94	(82)																12
16	Administrative and General	(3,091)	(289)	(2,768)	185	23	616			(1,569)	(29)	(302)					(173)	(636)	(242)	(248)	9			(2,596)	(11,110)
17	Total Operating Expenses	(3,091)	(289)	(2,768)	185	23	616	94	(82)	(1,569)	(29)	(302)			(559)		(173)	(636)	(242)	(248)	9	(117,919)	(153,417)	(2,596)	(282,991)
18																									
19	Depreciation																								
20	Amortization																								
21																									
22	Taxes																								
23	Property																								
24	Deferred Income Tax and ITC																								
25	Federal and State Income Tax	888	83	803	(53)	(6)	(177)	(27)	23	451	9	88	2,975	50	161	521	50	183	69	71	(3)	(5,448)	(2,267)	746	(809)
26	Payroll and Other			(24)							(2)	(6)													(33)
27	Total Taxes	888	83	778	(53)	(6)	(177)	(27)	23	451	7	82	2,975	50	161	521	50	183	69	71	(3)	(5,448)	(2,267)	746	(842)
28																									
29	Total Expenses	(2,202)	(206)	(1,990)	132	16	439	67	(58)	(1,118)	(22)	(219)	2,975	50	(398)	521	(123)	(453)	(172)	(177)	7	(123,366)	(155,684)	(1,850)	(283,834)
30																									
31	Allowance for Funds Used During Construc																								
32																									
33	Net Income	2,202	206	1,990	(132)	(16)	(439)	(67)	58	1,118	22	219	7,375	123	398	1,292	123	453	172	177	(7)	(13,506)	(5,620)	1,850	(2,007)
34																									
35	Calculation of Revenue Requirements																								
36	Rate Base																								
37	Required Operating Income																								
38	Operating Income	2,202	206	1,990	(132)	(16)	(439)	(67)	58	1,118	22	219	7,375	123	398	1,292	123	453	172	177	(7)	(13,506)	(5,620)	1,850	(2,007)
39	Income Deficiency	(2,202)	(206)	(1,990)	132	16	439	67	(58)	(1,118)	(22)	(219)	(7,375)	(123)	(398)	(1,292)	(123)	(453)	(172)	(177)	7	13,506	5,620	(1,850)	2,007
40	**Revenue Deficiency**	**(3,091)**	**(289)**	**(2,792)**	**185**	**23**	**616**	**94**	**(82)**	**(1,569)**	**(31)**	**(308)**	**(10,350)**	**(173)**	**(559)**	**(1,814)**	**(173)**	**(636)**	**(242)**	**(248)**	**9**	**18,954**	**7,887**	**(2,596)**	**2,816**

Northern States Power Company
PRECEDENTIAL ADJUSTMENT DETAIL SCHEDULE
2022 Plan Year
($000's)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)	(25)	(26)
		Precedential																							
Line No.	NSPM - 11 Bridge by Report Label	NSPM-Advertising (Trad)	NSPM-Assn Dues (Trad)	NSPM-Aviation	NSPM-Chamber of Commerce Dues	NSPM-Customer Deposits - A&G Expense (Trad)	NSPM-Donations (Trad)	NSPM-Econ Dev Donations (Trad)	NSPM-Econ Develop (Trad)	NSPM-Employee Expenses	NSPM-Foundation Admin	NSPM-Investor Relations	NSPM-Monticello EPU Commission Order No Return	NSPM-Nobles Disallowed Assets	NSPM-Nuclear Retention Removal	NSPM-Other Revenue to 3 Year Average Adj	NSPM-Pension Discount Rate Int	NSPM-Pension Non-Qual Restoration Removal	NSPM-Pension Non-Qual SERP Removal	NSPM-Pension Retiree Medical	NSPM-Pension Tracker Difference	NSPM-Remove Asset Trading	NSPM-Remove NonAsset Trading	NSPM-Remove NonAsset Trading Fully Allocated Costs	Total
1																									
2	Operating Revenues																								
3	Retail Revenue																								
4	Other Operating												9,107	159		1,589						(136,873)	(164,945)		(290,963)
5	Total Revenue												9,107	159		1,589						(136,873)	(164,945)		(290,963)
6																									
7	Expenses																								
8	Operating Expenses																								
9	Power Production without regional mkts																								
10	Fuel & Purchased Energy																					(117,919)	(153,417)		(271,335)
11	Power Production																								
12	Transmission																								
13	Customer Accounting																								
14	Customer Service and Information																								
15	Sales, Econ Dev, & Other							94	(82)																12
16	Administrative and General	(3,122)	(287)	(2,127)	185	23	617			(1,512)	(30)	(306)					(174)	(629)	(165)	(218)	(50)			(2,557)	(10,352)
17	Total Operating Expenses	(3,122)	(287)	(2,127)	185	23	617	94	(82)	(1,512)	(30)	(306)					(174)	(629)	(165)	(218)	(50)	(117,919)	(153,417)	(2,557)	(281,675)
18																									
19	Depreciation																								
20	Amortization																								
21																									
22	Taxes																								
23	Property																								
24	Deferred Income Tax and ITC																								
25	Federal and State Income Tax	897	82	618	(53)	(6)	(177)	(27)	23	435	9	90	2,618	46		457	50	181	48	63	14	(5,448)	(3,313)	735	(2,660)
26	Payroll and Other			(25)							(2)	(6)													(33)
27	Total Taxes	897	82	594	(53)	(6)	(177)	(27)	23	435	7	84	2,618	46		457	50	181	48	63	14	(5,448)	(3,313)	735	(2,693)
28																									
29	Total Expenses	(2,224)	(204)	(1,533)	132	16	440	67	(58)	(1,078)	(23)	(223)	2,618	46		457	(124)	(448)	(118)	(155)	(35)	(123,366)	(156,730)	(1,822)	(284,368)
30																									
31	Allowance for Funds Used During Construc																								
32																									
33	Net Income	2,224	204	1,533	(132)	(16)	(440)	(67)	58	1,078	23	223	6,489	113		1,132	124	448	118	155	35	(13,506)	(8,215)	1,822	(6,595)
34																									
35	Calculation of Revenue Requirements																								
36	Rate Base																								
37	Required Operating Income																								
38	Operating Income	2,224	204	1,533	(132)	(16)	(440)	(67)	58	1,078	23	223	6,489	113		1,132	124	448	118	155	35	(13,506)	(8,215)	1,822	(6,595)
39	Income Deficiency	(2,224)	(204)	(1,533)	132	16	440	67	(58)	(1,078)	(23)	(223)	(6,489)	(113)		(1,132)	(124)	(448)	(118)	(155)	(35)	13,506	8,215	(1,822)	6,595
40	**Revenue Deficiency**	**(3,122)**	**(287)**	**(2,152)**	**185**	**23**	**617**	**94**	**(82)**	**(1,512)**	**(32)**	**(312)**	**(9,107)**	**(159)**		**(1,589)**	**(174)**	**(629)**	**(165)**	**(218)**	**(50)**	**18,954**	**11,528**	**(2,557)**	**9,255**

Northern States Power Company
PRECEDENTIAL ADJUSTMENT DETAIL SCHEDULE
2023 Plan Year
($000's)

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)	(25)	(26)
		Precedential																							
Line No.	NSPM - 11 Bridge by Report Label	NSPM-Advertising (Trad)	NSPM-Assn Dues (Trad)	NSPM-Aviation	NSPM-Chamber of Commerce Dues	NSPM-Customer Deposits - A&G Expense (Trad)	NSPM-Donations (Trad)	NSPM-Econ Dev Donations (Trad)	NSPM-Econ Develop (Trad)	NSPM-Employee Expenses	NSPM-Foundation Admin	NSPM-Investor Relations	NSPM-Monticello EPU Commission Order No Return	NSPM-Nobles Disallowed Assets	NSPM-Nuclear Retention Removal	NSPM-Other Revenue to 3 Year Average Adj	NSPM-Pension Discount Rate Int	NSPM-Pension Non-Qual Restoration Removal	NSPM-Pension Non-Qual SERP Removal	NSPM-Pension Retiree Medical	NSPM-Pension Tracker Difference	NSPM-Remove Asset Trading	NSPM-Remove NonAsset Trading	NSPM-Remove NonAsset Trading Fully Allocated Costs	Total
1																									
2	Operating Revenues																								
3	Retail Revenue																								
4	Other Operating												7,867	145		783						(136,873)	(164,017)		(292,095)
5	Total Revenue												7,867	145		783						(136,873)	(164,017)		(292,095)
6																									
7	Expenses																								
8	Operating Expenses																								
9	Power Production without regional mkts																								
10	Fuel & Purchased Energy																					(117,919)	(153,417)		(271,335)
11	Power Production																								
12	Transmission																								
13	Customer Accounting																								
14	Customer Service and Information																								
15	Sales, Econ Dev, & Other							94	(82)																12
16	Administrative and General	(3,153)	(286)	(2,554)	185	23	1,429			(1,562)	(30)	(311)					(175)	(619)	(124)	(190)	(19)			(2,559)	(9,947)
17	Total Operating Expenses	(3,153)	(286)	(2,554)	185	23	1,429	94	(82)	(1,562)	(30)	(311)					(175)	(619)	(124)	(190)	(19)	(117,919)	(153,417)	(2,559)	(281,270)
18																									
19	Depreciation																								
20	Amortization																								
21																									
22	Taxes																								
23	Property																								
24	Deferred Income Tax and ITC																								
25	Federal and State Income Tax	906	82	741	(53)	(6)	(411)	(27)	23	449	9	91	2,261	42		225	50	178	36	55	5	(5,448)	(3,047)	736	(3,102)
26	Payroll and Other			(25)							(2)	(6)													(34)
27	Total Taxes	906	82	716	(53)	(6)	(411)	(27)	23	449	7	85	2,261	42		225	50	178	36	55	5	(5,448)	(3,047)	736	(3,136)
28																									
29	Total Expenses	(2,247)	(204)	(1,838)	132	16	1,018	67	(58)	(1,113)	(23)	(226)	2,261	42		225	(125)	(441)	(88)	(135)	(13)	(123,366)	(156,464)	(1,824)	(284,405)
30																									
31	Allowance for Funds Used During Construc																								
32																									
33	Net Income	2,247	204	1,838	(132)	(16)	(1,018)	(67)	58	1,113	23	226	5,606	103		558	125	441	88	135	13	(13,506)	(7,554)	1,824	(7,690)
34																									
35	Calculation of Revenue Requirements																								
36	Rate Base																								
37	Required Operating Income																								
38	Operating Income	2,247	204	1,838	(132)	(16)	(1,018)	(67)	58	1,113	23	226	5,606	103		558	125	441	88	135	13	(13,506)	(7,554)	1,824	(7,690)
39	Income Deficiency	(2,247)	(204)	(1,838)	132	16	1,018	67	(58)	(1,113)	(23)	(226)	(5,606)	(103)		(558)	(125)	(441)	(88)	(135)	(13)	13,506	7,554	(1,824)	7,690
40	**Revenue Deficiency**	**(3,153)**	**(286)**	**(2,579)**	**185**	**23**	**1,429**	**94**	**(82)**	**(1,562)**	**(33)**	**(317)**	**(7,867)**	**(145)**		**(783)**	**(175)**	**(619)**	**(124)**	**(190)**	**(19)**	**18,954**	**10,601**	**(2,559)**	**10,791**

Wholesale Customer Study

Purpose

With respect to the costs and revenues related to serving wholesale customers, the Company and the Department of Commerce agreed in Docket No. E002/GR-12-961 as follows:

> The Company will provide as a compliance filing in future rate cases a wholesale customer study which shows all wholesale customers being served by the Company (including, but not limited to, full requirements, partial requirements, and market based wholesale customers), types of service being provided to each wholesale customer, costs and revenues associated with each wholesale customer, and a clear showing either that wholesale costs are allocated out of the retail rate case or that the revenues are included in the retail rate case, for all services provided to wholesale customers.[1]

This study provides the required information. Information in this study includes the types of services being provided to wholesale customers and the treatment of revenues and margins associated with wholesale customer transactions. The study does not address wholesale transmission revenues, which revenues and associated costs are discussed in detail in the Direct Testimony of Company witness Mr. Ian R. Benson.

All wholesale customers are provided services pursuant to bilateral agreements. These bilateral agreements define the scope of services for each wholesale customer, such as interfacing between the customer and the Midcontinent Independent System Operator, Inc. (MISO), including providing balancing services. Revenues from these customers are included in Other Revenues (e.g., for balancing services), and asset based margins for energy sales are passed through the fuel clause and removed from the cost of service. We also provide some non-asset based services to these customers (energy and capacity sales using financial instruments). Non-asset based margins (revenues less costs), as well as the fully-allocated costs of those activities, are removed from the cost of service.

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[1]Docket No. E002/GR-12-961, Issues List at 19 (May 22, 2013).

Historic Wholesale Cost Assignment Method

Through the mid-1990s, the Company provided bundled cost-based "requirements" wholesale services to numerous municipal utilities connected to the NSP transmission system. Total municipal loads were in the hundreds of megawatts. Some wholesale municipal customers were full requirements customers and purchased all of their capacity and energy from the Company. Other municipal customers received "preference power" allocations from the Western Area Power Administration for a portion of their power supply needs and purchased partial requirements service from the Company for the remainder. However, during the 1970s through the 1990s, new municipal power agencies (such as Southern Minnesota Municipal Power Agency, Central Minnesota Municipal Power Agency, Minnesota Municipal Power Agency, etc.) were created to serve the power supply needs of these and other municipal customers, and most of the cost-based requirements wholesale sales agreements expired.

Previously, when municipal power loads were significant, costs were allocated to a wholesale municipal jurisdiction similar to the process used to allocate costs to the Company's retail jurisdictions (Minnesota, North Dakota and South Dakota). Fixed production costs were allocated based on coincident peak demand, and variable production costs were allocated based on the energy allocator. This process also included the direct assignment of some costs to the Wholesale jurisdiction for services being directly provided to those customers (such as distribution transformation services).

In addition, the Company direct-assigned costs where possible or allocated customer accounting, customer information, and sales costs to the jurisdiction based on the number of customers. Similarly, administrative and general (A&G) costs were allocated or direct assigned as appropriate based on functional organization. Specifically, if A&G costs were incurred by the Energy Supply, Commercial Operations or Transmission organizations, they were allocated to retail and wholesale jurisdictions based on the jurisdictional demand allocator.

Changes in Wholesale Market and Test Year Wholesale Customers

As of 2012, the Company directly served only three traditional cost-based requirements wholesale customers: the City of Ada, City of Kasota, and Heartland Consumers Power District (HCPD) for the City of Lake Crystal. These customers comprised less than onetenth of one percent of total Company demand and energy requirements. The rates and services for sales to these customers were regulated by the Federal Energy Regulatory Commission (FERC) under tariffs or contracts on file with FERC. The contract rates were indexed to the Minnesota Commercial and Industrial (C&I) General Service Retail or Time of Day rates.

However, excess capacity and energy on a short to mid-term basis has increased competition and put downward pressure on pricing. Given the market dynamics, the Company's wholesale customers determined it was in their best interest to purchase energy on the open market rather than continuing service under cost based contracts. Where in the past, these customers mitigated energy cost volatility risk by entering into full requirements agreements with the Company, they now prefer to take on that risk themselves, given the current market environment. Therefore, the Company no longer has any cost-based requirements wholesale customers in the 2021 test year or the 2022 and 2023 plan years.

Services Provided to Wholesale Customers in 2021

The Company provides services to wholesale customers through the execution of transactions that fall into three main categories: Asset Based Transactions, Non-Asset Based Transactions, and Other Wholesale Transactions.

Asset based transactions involve the sale of excess energy and capacity available from Company owned generation assets. Both costs and revenues associated with asset-based energy and capacity transactions are included in the unadjusted retail rate case cost of service, and all margins resulting from asset-based energy sales are excluded from the 2021 test year as they are returned to ratepayers through the Fuel Clause Adjustment pursuant the Company's 2005 electric rate case (Docket No. E002/GR-05-1428).

Non-asset based transactions are those in which energy and/or capacity is purchased from a third party and resold for profit. Non-asset based transactions are undertaken as energy market opportunities to make revenue and are unrelated to meeting the needs of our retail customers. These transactions are included in the unadjusted retail rate case cost of service. However, the fully allocated costs of non-asset based trading activity are removed from the cost of service study, and all margins (revenues less costs) associated with these activities are also removed and retained by the Company.

The Other Wholesale Transaction category includes transactions related to MISO interfacing services, an energy services agreement with **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]**, and the pass-through of MISO charges to the appropriate parties. The costs of these services are included in the cost of service, and all revenues are recorded as Other Revenue and are credited to retail customers through the cost of service.

Attachment A to this schedule provides a list of the types of services provided, and the ratemaking treatment for each type of service. Attachment B to this schedule provides a wholesale customer summary including all current agreements by customer and the expected revenues for the years 2021-2023.

Test Year Wholesale Transactions

During 2021, the Company expects to engage in wholesale transactions in the following categories: asset based energy sales, asset based capacity sales, non-asset based sales and other wholesale transactions including MISO interface and scheduling services, energy services agreements, and pass through charges. These transactions and their impact on the test year are discussed below.

Asset Based Energy Sales Transactions
Asset based energy sales margins are generated through the sale of available excess energy either directly into the MISO market or to specific wholesale customers through bilateral agreements. Pricing of excess energy sales to MISO are based on prevailing locational marginal prices (LMP) that clear in the Day Ahead or Real Time markets. Pricing of transactions made directly by the Company to specific wholesale customers is based on the current marginal cost of generation at the time of the transaction, and the Company does not make a margin on these sales. Instead, the Company charges a scheduling fee for providing this service. Therefore, the margin on these sales is equal to the scheduling fee paid by the customer. Net margins earned on all asset based energy sales, including the scheduling fees, are returned to ratepayers through the Fuel Clause Adjustment.

Table 1 below shows the asset based energy sales margins for 2019 and 2021. In addition, Volume 4 MYRP Workpapers, Section VIII Adjustments, Tab A21, Trading:

Asset-Based Margin, includes all calculations related to asset based transactions and their impact on the test year. The revenues associated with these trades flow through to Other Electric Revenues in the income statement as shown in Volume 4, Section IV, Revenue, Tab R5, Other Revenues.

Table 1

Asset Based Energy Sales Transactions

State of Minnesota Jurisdiction	2019	2021 Budget
Revenues	$180.4M	$136.9M
COGS *	($152.8M)	($123.4M)
Margin	**$27.6M**	**$13.5M**

*COGS Information includes Revenue Sharing Thru the FCA

Asset Based Capacity Sales Transactions
Revenues for asset based capacity sales are included in the cost of service and are not included in the asset based margin adjustment (which includes only the net margin for asset based energy sales). These capacity sales revenues, labeled "OTHER MISC SERVICE REV)" and totaling $530,575 are included in Other Electric Revenues in the income statement as shown in Volume 4, Section IV, Revenue, Tab R5, Other Revenues.

Non-Asset Based Transactions
Non-asset based transactions are not included in the retail rate case: revenues and their associated fully allocated embedded costs are removed from the cost of service, and all margins are retained by the Company pursuant to the settlement in the Company's 2011 rate case (Docket No. E002/GR-10-971) . These adjustments are discussed in Volume 4, Section VIII Adjustments, Tab A22, Trading: Non-Asset-Based Margin and Tab A23, Trading: Non Asset-Based Admin.

Other Wholesale Transactions
This category includes the three types of wholesale customer agreements not included in the asset based and non-asset based categories: MISO Interface/Scheduling, Energy Services Agreements, and Pass Through Charges (for a detailed explanation of each category, please see Attachment A to this schedule). In each case, revenues and costs associated with these transactions are included in the rate case, and no adjustment is made to the income statement or cost of service. As shown in Attachment B to this schedule, revenues from Other Wholesale Transactions are expected to be $662,417 in 2021. These revenues flow into Other Operating Revenue as shown in Volume 4, Section IV, Revenue, Tab R5, Other Revenues.

Conclusions

After reviewing the services anticipated to be provided to wholesale customers in 2021 and the transactions associated with those services, the Company concludes that the ratemaking treatment of these transactions is consistent with existing regulatory practices:

- Wholesale transaction costs and revenues are held above the line except with respect to non-asset based transactions
    - Non-asset based margins are adjusted out of the test year and retained by the Company
    - Non-asset based trading costs are adjusted out of the test year, reducing the revenue requirement
- Asset based energy sales margins are shared with rate payers through the Fuel Clause Adjustment
- Other Wholesale Transactions are included in the test year and offset revenue requirements

The Company does not recommend any changes to the treatment of wholesale customers or the revenues and costs associated with providing these services. In addition, the Company concludes that there are no adverse impacts on ratepayers as a result of providing these services or the ratemaking treatment of the associated transactions.

PUBLIC DOCUMENT –
NOT PUBLIC DATA HAS BEEN EXCISED

Deal Category	Deal Type	Scope of Services	Ratemaking Treatment
Energy	Asset Based Energy Sale	These Asset Based Energy deals are for the sale of energy generated by NSP's own assets. The quantity is scheduled by mutual agreement. NSP earns either a fixed monthly fee or per MWh scheduling fee over and above the cost of energy. The quantity is determined based upon forecasted volumes which may vary from actual usage.	**Asset Based - Fuel Clause Adjustment** 100% of the margins are returned to ratepayers through the Fuel Clause Adjustment
	Non-Asset Based Energy Sale	A Non-Asset Based Energy deal is for the sale of a specified quantity of MWh at a given price throughout the contract term. The energy sold to the counterparty is not generated by NSP's own assets. Instead NSP either (1) purchases a like product to back all or a part of the position and/or (2) purchases the requisite energy off the MISO market day ahead or in real time depending upon risk tolerance. Business Rules require that any purchase or sale of energy be offered to the NSP system first. If the system passes on the purchase or sale it can then be assigned to the prop book.	**Non-Asset Based - Margin Adjustment** Margins are retained by the Company. Therefore, both the margins and the associated O&M costs are excluded from the test year
Capacity	Asset Based Capacity Sale	An Asset Based Capacity deal is for the sale of MISO Zonal Resource Credits ("ZRCs", which are fungible instruments that represent one MW of Unforced Capacity from a Planning Resource over a MISO planning year). For these deals, the capacity sold is provided by NSP's projected surplus assets.	**Asset Based - No Adjustment** Revenues are included as an offset to the revenue requirement. Associated fixed costs are included in the Cost of Service Study.
	Non-Asset Based Capacity Sale	A Non-Asset Based Capacity deal is for the sale of MISO ZRCs that are backed by the purchase of a like product. Business Rules require that any purchase or sale of capacity be offered to the NSP system first. If the system passes on the purchase or sale it can then be assigned to the prop book	**Non-Asset Based - Margin Adjustment** Margins are retained by the Company. Therefore, both the margins and the costs are excluded from the test year
Other	MISO Interface/Scheduling	In a MISO Interface deal NSP provides services necessary for the counterparty to operate in the MISO market. Such services include Day Ahead load bids, FinScheds, Capacity reporting for MISO Module E, and others as specified in the individual contracts. Pricing is determined on a per MWh basis and may vary depending upon actual usage.	**Other Wholesale Transactions - No Adjustment** Revenues are included as an offset to the revenue requirement. Associated O&M costs are included in the Cost of Service Study.
	Energy Services Agreement	The Company currently has only one Energy Services Agreement in place. This deal governs the fee paid to NSP for the preservation of transmission reservations, which improves **[PROTECTED DATA BEGINS PROTECTED DATA ENDS]** ability to import and export power. The annual service fee payments are payable to NSP in advance of the service year.	**Other Wholesale Transactions - No Adjustment** Revenues are included as an offset to the revenue requirement. Associated O&M costs are included in the Cost of Service Study.
	MISO Pass Through	These pass through arrangements specify that all MISO charges including transmission service, congestion AND loss, and ancillary services are a pass through. NSP earns no margin on such deals.	**N/A** There are no revenues or expenses requiring ratemaking treatment as these transactions are merely a pass through of MISO charges.

NSP Wholesale Customer Summary
as of July 24, 2020

Background information

Energy deals

Gen book sales

A deal in the gen book energy column (i.e. NWEC partial requirements) is for the sale of energy that is generated by NSP's own assets. The quantity is scheduled by the counterparty for use as an intermediate/peaking resource. NSP earns either a fixed monthly fee or per MWh scheduling fee over and above the cost of energy. The margin for these deals is determined based upon forecasted volumes and may vary depending upon actual usage.

Prop book sales

A deal in the prop book energy column (i.e. Ada energy) is for the sale of a specified quantity of MWs at a given price throughout the contract term. The energy sold to the counterparty is not generated by NSP's own assets. Instead NSP either (1) purchases a like product to back the position (a bilateral deal) or (2) purchases the requisite energy off the MISO market (a market based deal).

Capacity deals

Gen book

A deal in the gen book capacity column (i.e. Ada capacity) is for the sale of MISO Zonal Resource Credits ("ZRCs", which are fungible instruments that represent one MW of Unforced Capacity from a Planning Resource over a MISO planning year). For these deals, the capacity sold is provided by NSP's projected surplus assets.

Prop book

A deal in the prop book capacity deals column (i.e. Basin Electric capacity) is for the sale of MISO ZRCs that are backed by the purchase of a like product.

Other deals

MISO interface/scheduling

A deal in the MISO interface services & scheduling fees column (i.e. Ada energy) is for NSP providing services necessary for the counterparty to operate in the MISO market. Such services include Day Ahead load bids, FinScheds, Capacity reporting for MISO Module E, and others as specified in the individual contracts. Pricing is determined on a per MWh basis and may vary depending upon actual usage.

[PROTECTED DATA BEGINS

Energy services agreement

PROTECTED DATA ENDS]

Pass through charges

A deal in the pass through charges column (i.e. Ada energy) is to specify that all MISO charges including transmission service, congestion & loss, and ancillary services are a pass through. NSP earns no margin on such deals.

2021

Counterparty	Contract term	Energy: Gen: partial requirements 3	Energy: Prop: bilateral or market based	Capacity: Gen capacity	Capacity: Prop capacity	Other: MISO interface svcs & Scheduling Fees	Other: Energy services agreement	Other: Pass through charges
GL Account		4073001	4073051	4073151	4073051	4280381	4280381	4073051
Revenues		**[PROTECTED DATA BEGINS**						
Ada	1/1/17-12/31/21		1					2
Ada	1/1/17-12/31/21							
Ada	1/1/12-12/31/27							
Kasota	1/1/17-12/31/21		1					
Kasota	1/1/17-12/31/21							
Kasota	1/1/22-12/31/27							
NWEC	5/1/15 - 12/31/20							
NWEC	1/1/21 - 12/31/21		1					
NWEC	6/1/20 - 5/31/21							
NCP	5/1/15 - 12/31/20							
NCP	1/1/21 - 12/31/21		1					
NCP	6/1/20 - 5/31/21							
Dahlberg Light & Power Co.	1/1/17 - 12/31/27							
Dahlberg Light & Power Co.	1/1/14 - 12/31/27		1					
Dahlberg Light & Power Co.	6/1/20 - 5/31/21							
[PROTECTED DATA BEGINS								
PROTECTED DATA ENDS]								
Great Lakes Utilities	6/1/20 - 5/31/21							
Great River Energy	6/1/22-5/31/24							
Costs						**PROTECTED DATA ENDS]**		
Ada	1/1/17-12/31/21		1			5 & 8		2
Ada	1/1/17-12/31/21			4				
Ada	1/1/12-12/31/27					5 & 8		2
Kasota	1/1/17-12/31/21		1			5 & 8		2
Kasota	1/1/17-12/31/21			4				
Kasota	1/1/22-12/31/27							
NWEC	5/1/15 - 12/31/20							
NWEC	1/1/21 - 12/31/21		1					
NWEC	6/1/20 - 5/31/21							
NCP	5/1/15 - 12/31/20							
NCP	1/1/21 - 12/31/21		1					
NCP	6/1/20 - 5/31/21							
Dahlberg Light & Power Co.	1/1/17 - 12/31/27					5		
Dahlberg Light & Power Co.	1/1/14 - 12/31/27		1					
Dahlberg Light & Power Co.	6/1/20 - 5/31/21							
[PROTECTED DATA BEGINS								
PROTECTED DATA ENDS]								
Great Lakes Utilities	6/1/20 - 5/31/21							

2022

Counterparty	Contract term	Energy: Gen: partial requirements 3	Energy: Prop: bilateral or market based	Capacity: Gen capacity	Capacity: Prop capacity	Other: MISO interface svcs & Scheduling Fees	Other: Energy services agreement	Other: Pass through charges
GL Account		4073001	4073051	4073151	4073051	4280381	4280381	4E+06
Revenues		**[PROTECTED DATA BEGINS**						
Ada	1/1/17-12/31/21							
Ada	1/1/17-12/31/21							
Ada	1/1/12-12/31/27							
Kasota	1/1/17-12/31/21							
Kasota	1/1/17-12/31/21							
Kasota	1/1/22-12/31/27							
NWEC	5/1/15 - 12/31/20							
NWEC	1/1/21 - 12/31/21							
NWEC	6/1/20 - 5/31/21							
NCP	5/1/15 - 12/31/20							
NCP	1/1/21 - 12/31/21							
NCP	6/1/20 - 5/31/21							
Dahlberg Light & Power Co.	1/1/17 - 12/31/27							
Dahlberg Light & Power Co.	1/1/14 - 12/31/27							
Dahlberg Light & Power Co.	6/1/20 - 5/31/21							
Great Lakes Utilities	6/1/20 - 5/31/21							
Great River Energy	6/1/22-5/31/24							
Costs						**PROTECTED DATA ENDS]**		
Ada	1/1/17-12/31/21					5 & 8		2
Ada	1/1/17-12/31/21			4				
Ada	1/1/12-12/31/27					5 & 8		2
Kasota	1/1/17-12/31/21					5 & 8		2
Kasota	1/1/17-12/31/21			4				
Kasota	1/1/22-12/31/27							
NWEC	5/1/15 - 12/31/20							
NWEC	1/1/21 - 12/31/21							
NWEC	6/1/20 - 5/31/21							
NCP	5/1/15 - 12/31/20							
NCP	1/1/21 - 12/31/21							
NCP	6/1/20 - 5/31/21							
Dahlberg Light & Power Co.	1/1/17 - 12/31/27					5		
Dahlberg Light & Power Co.	1/1/14 - 12/31/27							
Dahlberg Light & Power Co.	6/1/20 - 5/31/21							
Great Lakes Utilities	6/1/20 - 5/31/21							

2023

Counterparty	Contract term	Energy: Gen: partial requirements 3	Energy: Prop: bilateral or market based	Capacity: Gen capacity	Capacity: Prop capacity	Other: MISO interface svcs & Scheduling Fees	Other: Energy services agreement	Other: Pass through charges
GL Account		4073001	4073051	4073151	4073051	4280381	4280381	4073051
Revenues		**[PROTECTED DATA BEGINS**				**[PROTECTED DATA BEGINS**		
Ada	1/1/17-12/31/21							
Ada	1/1/17-12/31/21							
Ada	1/1/12-12/31/27							2
Kasota	1/1/17-12/31/21							
Kasota	1/1/17-12/31/21							
Kasota	1/1/22-12/31/27							2
NWEC	5/1/15 - 12/31/20							
NWEC	1/1/21 - 12/31/21							
NWEC	6/1/20 - 5/31/21							
NCP	5/1/15 - 12/31/20							
NCP	1/1/21 - 12/31/21							
NCP	6/1/20 - 5/31/21							
Dahlberg Light & Power Co.	1/1/17 - 12/31/27							
Dahlberg Light & Power Co.	1/1/14 - 12/31/27							
Dahlberg Light & Power Co.	6/1/20 - 5/31/21							
Great Lakes Utilities	6/1/20 - 5/31/21							
Great River Energy	6/1/22-5/31/24							
Costs					**PROTECTED DATA ENDS**			**PROTECTED DATA ENDS]**
Ada	1/1/17-12/31/21					5 & 8		2
Ada	1/1/17-12/31/21			4				
Ada	1/1/12-12/31/27					5 & 8		2
Kasota	1/1/17-12/31/21					5 & 8		2
Kasota	1/1/17-12/31/21			4				
Kasota	1/1/22-12/31/27							
NWEC	5/1/15 - 12/31/20							
NWEC	1/1/21 - 12/31/21							
NWEC	6/1/20 - 5/31/21							
NCP	5/1/15 - 12/31/20							
NCP	1/1/21 - 12/31/21							
NCP	6/1/20 - 5/31/21							
Dahlberg Light & Power Co.	1/1/17 - 12/31/27					5		
Dahlberg Light & Power Co.	1/1/14 - 12/31/27							
Dahlberg Light & Power Co.	6/1/20 - 5/31/21							
Great Lakes Utilities	6/1/20 - 5/31/21							

1 NSPM's proprietary book budget after joint operating agreement for 2021-2023 is targeted at $17.68M, $16.4M, and $17.5M, respectively. This transaction is part of the proprietary budget target however we do not specifically identify the revenue and cost of the deals that fall within the $17M, therefore this information is not presented within this analysis. The margin of this transaction is not shared with Minnesota.

2 All MISO charges including transmission service, congestion & loss, and ancillary services are passed through to the customer. These charges are variable on a monthly basis and are not forecasted. Due to the pass-through process, income is equal to cost and there is no incremental margin to NSP.

3 These generation book partial requirements customers purchase energy at Time of Day rates and are charged either a fixed monthly scheduling fee or a fee based upon MWhs scheduled. Accordingly, the revenue and cost associated with the energy will fluctuate in accordance with market prices but will not impact the margin on the deals. The margin will always be the scheduling fee on these deals. Therefore, the revenue shown above is only the scheduling fee margin (which is shared 100% with ratepayers) and cost information is not presented.

4 The cost for generation book capacity is embedded within the cost of fuel for NSP and is not specifically identified.

5 The cost for MISO interface services is embedded within operating expense for NSP and is not specifically identified.

6 The cost for the energy services agreement is embedded within operating expense for NSP and is not specifically identified.

7 N/A

8 Both the Ada & Kasota Agreements were extended from 2021-2027, which result in revenues in the Gen Capacity and Energy Service Agreements.

CAPACITY COST STUDY
NSP Summary

Long-Term Purchased Power Capacity Cost Forecast by Contract - Minnesota 2021 Rate Case Filing

[PROTECTED DATA BEGINS…

	Byllesby 1	Byllesby 2	Hastings	LSP	MH.Part	St.Cloud	Mankato	Mankato II*	Cannon Falls	Total $000
2021 Jan										
2021 Feb										
2021 Mar										
2021 Apr										
2021 May										
2021 Jun										
2021 Jul										
2021 Aug										
2021 Sep										
2021 Oct										
2021 Nov										
2021 Dec										
2022 Jan										
2022 Feb										
2022 Mar										
2022 Apr										
2022 May										
2022 Jun										
2022 Jul										
2022 Aug										
2022 Sep										
2022 Oct										
2022 Nov										
2022 Dec										
2023 Jan										
2023 Feb										
2023 Mar										
2023 Apr										
2023 May										
2023 Jun										
2023 Jul										
2023 Aug										
2023 Sep										
2023 Oct										
2023 Nov										
2023 Dec										
2021	-	-	-	-	-	-	-	-	-	159,206
2022	-	-	-	-	-	-	-	-	-	159,691
2023	-	-	-	-	-	-	-	-	-	162,732

…PROTECTED DATA ENDS]

*The contract with Makato II begins in June 1, 2019

Description of Terms in Following Pages (as per DOC IR-041 in Docket No. E002/GR-12-961):

Demand Rate	Specifies the rate that is paid per unit of capacity that is purchased.
FOM Rate	Fixed Operations and Maintenance rate; defined in each contract.
Capacity Factor Adjustment	Lowers the capacity payment if the facility is producing below a capacity factor of 70% as defined in the contract.
Fuel Inventory Rate	Defined in contracts and is fixed for the term of the agreement.
FR1	Fixed rate as defined by contract
FR2	Fixed rate as defined by contract
FR3	Fixed rate as defined by contract
AF1	Adjustment Factor-1 as defined by contract
BF1	Bonus Factor - 1 as defined by contract
CLF	Capacity Loss Factor as defined by contract
CTUP	Capacity True-Up Payment
CCTF	Committed Capacity True-up Factor based on the Tested Capacity Ratio (TCR) determined by the Committed Capacity Test

Calculation Maps are included for each following page.

CAPACITY COST STUDY
NSP Summary

	A	B	C	D = A+B+C	E	F	D*E*F/1000
	[PROTECTED DATA BEGINS…						
2021 Jan							
2021 Feb							
							…PROTECTED DATA ENDS]

CAPACITY COST STUDY
NSP Summary

	A	B	C	D = A+B+C	E	F	D*E*F/1000
2021 Jan							
2021 Feb							

[PROTECTED DATA BEGINS…

…PROTECTED DATA ENDS]

CAPACITY COST STUDY
NSP Summary

[PROTECTED DATA BEGINS…

	A	B	C = A+B	D	F	C*D*F/1000
2021 Jan						
2021 Feb						
2021 Mar						
2021 Apr						
2021 May						
2021 Jun						
2021 Jul						
2021 Aug						
2021 Sep						
2021 Oct						
2021 Nov						
2021 Dec						
2022 Jan						
2022 Feb						
2022 Mar						
2022 Apr						
2022 May						
2022 Jun						
2022 Jul						
2022 Aug						
2022 Sep						
2022 Oct						
2022 Nov						
2022 Dec						
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2023 May						
2023 Jun						
2023 Jul						
2023 Aug						
2023 Sep						
2023 Oct						
2023 Nov						
2023 Dec						

…PROTECTED DATA ENDS]

CAPACITY COST STUDY
NSP Summary

[PROTECTED DATA BEGINS…

	A	B	C	D = B*C	E	F	G	H	I	J	K	L = (A*(D+E+F)*G*H*I*K+J)/12/1000	M	L-M
2021 Jan														
2021 Feb														
2021 Mar														
2021 Apr														
2021 May														
2021 Jun														
2021 Jul														
2021 Aug														
2021 Sep														
2021 Oct														
2021 Nov														
2021 Dec														
2022 Jan														
2022 Feb														
2022 Mar														
2022 Apr														
2022 May														
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2023 Sep														
2023 Oct														
2023 Nov														
2023 Dec														

… PROTECTED DATA ENDS]

CAPACITY COST STUDY
NSP Summary
Purchaser: Northern States Power Company
Seller: The Manitoba Hydro -Electric Board (PPA dated May 27, 2010)

[PROTECTED DATA BEGINS…

…PROTECTED DATA ENDS]

CAPACITY COST STUDY
NSP Summary

[PROTECTED DATA BEGINS…

	A	B	C	D = A+B+C	E	F	D*E*F/1000-4.16667
2021 Jan							
2021 Feb							
2021 Mar							
2021 Apr							
2021 May							
2021 Jun							
2021 Jul							
2021 Aug							
2021 Sep							
2021 Oct							
2021 Nov							
2021 Dec							
2022 Jan							
2022 Feb							
2022 Mar							
2022 Apr							
2022 May							
2022 Jun							
2022 Jul							
2022 Aug							
2022 Sep							
2022 Oct							
2022 Nov							
2022 Dec							
2023 Jan							
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2023 Mar							
2023 Apr							
2023 May							
2023 Jun							
2023 Jul							
2023 Aug							
2023 Sep							
2023 Oct							
2023 Nov							
2023 Dec							

…PROTECTED DATA ENDS]

CAPACITY COST STUDY
NSP Summary
Purchaser: Northern States Power
Seller: Mankato Energy Center, LLC (Purchased Power Agreement dated March 11, 2004)

[PROTECTED DATA BEGINS…

…PROTECTED DATA ENDS]

[PROTECTED DATA BEGINS…

Contracted Capacity (Net Capacity) - KW:

…PROTECTED DATA ENDS]

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023

[PROTECTED DATA BEGINS…

…PROTECTED DATA ENDS]

Contract Capacity Payment Factors:
[PROTECTED DATA BEGINS…

…PROTECTED DATA ENDS]

2021 Fixed Charges:	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total

[PROTECTED DATA BEGINS…

2022 Fixed Charges:	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total

2023 Fixed Charges:	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total

…PROTECTED DATA ENDS]

CAPACITY COST STUDY
NSP Summary
Purchaser: Northern States Power
Seller: Mankato Energy Center II, LLC (Purchased Power Agreement dated xx/xx/xx)

[PROTECTED DATA BEGINS…

…PROTECTED DATA ENDS]

[PROTECTED DATA BEGINS…
Contracted Capacity (Net Capability) - KW:

…PROTECTED DATA ENDS]

	1	2	3	4	5	6	7	8	9	10	11	12	13
	6/1/19-5/31/20	6/1/20-5/31/21	6/1/21-5/31/22	6/1/22-5/31/23	6/1/23-5/31/24	6/1/24-5/31/25	6/1/25-5/31/26	6/1/26-5/31/27	6/1/27-5/31/28	6/1/28-5/31/29	6/1/29-5/30/30	6/1/30-5/31/31	6/1/31-5/31/32

[PROTECTED DATA BEGINS…

***Capacity Rate (B) changes on XX/XX of each year**

…PROTECTED DATA ENDS]

Contract Capacity Payment Factors:
[PROTECTED DATA BEGINS…

…PROTECTED DATA ENDS]

2021 Fixed Charges:	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total

[PROTECTED DATA BEGINS…

2022 Fixed Charges:	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total

2023 Fixed Charges:	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total

…PROTECTED DATA ENDS]

CAPACITY COST STUDY
NSP Summary
Purchaser: **Northern States Power**
Seller: **Invenergy Cannon Falls, LLC - Cannon Falls Energy Center**

[PROTECTED DATA BEGINS…

Expected Start Date:
Expected Termination Date:

[PROTECTED DATA BEGINS…

Contracted Capacity (Net Capability) - KW:

Net Dependable Capability:

…PROTECTED DATA ENDS]

Fixed Charge Prices:	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023

[PROTECTED DATA BEGINS…

…PROTECTED DATA ENDS]

Fixed Charge Factors:

[PROTECTED DATA BEGINS…

…PROTECTED DATA ENDS]

Fixed Charges - 2021:	January	February	March	April	May	June	July	August	September	October	November	December	Annual Total

[PROTECTED DATA BEGINS…

Fixed Charges - 2022:	January	February	March	April	May	June	July	August	September	October	November	December	Annual Total

Fixed Charges - 2023:	January	February	March	April	May	June	July	August	September	October	November	December	Annual Total

…PROTECTED DATA ENDS]

Economic Development Analysis - Commercial Inputs

2021 Economic Development

Average Cost for Industrial/Commercial installation of 500KVA Txfs.	$	34,000	Schedule 16, Attachment B, Line 1
Annual Revenue per Customer	$	146,461	Schedule 16, Attachment B, Line 23
Total Economic Development Expenses in Test Year	$	175,881	Schedule 16, Attachment B, Line 18
Other Revenue Requirements Associated with Additional ED Customer	$	18,650	Schedule 16, Attachment B, Lines 16, 19, 20, 21
Total Revenue Requirements	$	194,531	Schedule 16, Attachment B, Line 22
Potential Customer Benefit in Year 1	$	(48,070)	Schedule 16, Attachment B, Line 24
Potential Customer Benefit in Year 2	$	126,855	Schedule 16, Attachment B, Line 24
Potential Cumulative Customer Benefit over Life of Investment	$	1,353,562	Schedule 16, Attachment B, Line 26

Non-Asset Based Trading Cost Study

Introduction

Northern States Power Company, doing business as Xcel Energy (Xcel Energy, NSPM, or the Company) agreed in its 2011 test year general electric rate case (Docket No. E002/GR-10-971 or 2010 Rate Case) to two items regarding non-asset based trading:

> "The Company has agreed to submit an incremental and fully-allocated cost study of non-asset-based trading with its next rate case;"[1] and

> "…would remove non-asset based margins and their associated embedded costs from the revenue requirement…"[2]

In Docket No. E002/GR-15-826, the Company requested that it only be required to submit a fully allocated cost study because the incremental cost study is not used to determine the level of costs to charge to this activity. That request was not opposed. Consequently, this report summarizes the cost study undertaken by the Company to determine the fully allocated cost of non-asset based trading activity.

Background

There are two main categories of short-term wholesale trading: asset based transactions and non-asset based transactions. Asset based transactions involve the sales of excess energy or capacity from Company-owned generation assets. Non-asset based transactions are undertaken as energy market opportunities to make revenues, and are unrelated to meeting the needs of the Native Load customers (retail customers and requirements wholesale customers taking service at cost-based rates).

Non-asset based trading transactions are those in which:

- Energy or capacity is purchased from a third party but is unrelated to serving native load
- That energy or capacity is resold for profit

The costs that are being examined in this study are related exclusively to non-asset based trading.

[1] Docket No. E002/GR-10-971 ALJ Report, Findings of Fact, February 22, 2012; ALJ Findings 278 and 315.
[2] Docket No. E002/GR-10-971 PUC Findings of Fact, Conclusions and Order, May 14, 2012; page 9.

Prior to the 2010 Rate Case, the Company shared non-asset based margins with customers. In its 2009 test year general electric rate case (Docket No. E002/GR-08-1065 or 2008 Rate Case), the Company committed to perform both an incremental and fully distributed cost study of non-asset based trading activities as part of its next general electric rate case application. Therefore, the 2010 Rate Case included the first such study.

In the settlement of the 2010 Rate Case proceedings, the Company agreed to change the ratemaking treatment of non-asset based trading margins: the fully allocated cost of non-asset based trading activity is now excluded from the Company's revenue requirements, and the non-asset based trading margins are retained by the Company. Further, as noted above the Company's proposal to provide solely a fully allocated cost study in this case was not opposed in the Company's most recent past rate case. This study therefore provides support for the fully allocated cost adjustment made for the 2021 test year and 2022-2023 plan years.

Fully Allocated Cost Analysis

The Company defines fully allocated costs as the incremental costs along with a reasonable contribution of common overhead costs. There are two components of fully allocated costs – 1) expenses and 2) a share of capital costs. All expenses recorded as non-asset based trading are considered fully distributed costs (i.e., an allocation percentage has not been applied to non-productive labor costs – for example labor loadings such as pension and insurance – as was done in the incremental cost study). In addition, Information Technology (IT) systems costs that are necessary to support these activities are included in the fully allocated costs. In total, the fully allocated O&M costs include the following components: Labor, indirect labor overheads (which includes rents), and IT system costs.

Labor

The labor itself is directly recorded as being non-asset based trading. However, the Company has also included labor overhead allocations (for example pension and insurance) to the directly assigned labor in the fully allocated section of the study.

Labor Overhead

In addition to the labor overhead costs identified in the labor section above, a labor overhead rate of 14.69 percent was also applied to non-asset based trading labor. This is the same rate applied to total labor and labor loadings for charges to the non-regulated businesses within NSPM and for third party billings.

Attachment A shows the fully allocated labor and overhead costs associated with non-asset based trading for 2017-2019 actuals and 2021-2023 MYRP forecast.

IT Systems
In addition to the labor and labor overhead expenses, the Company identified IT systems used to facilitate non-asset based trading. The table below summarizes the computer systems identified which support non-asset based trading activities:

System	**Description**
Business Objects (BO)	Query tool
Commodity XL	Manage commodity trading logistics and risk management
CXT	Customer Experience Transformation
SAP/SAP GL	General ledger system used to account for trade activity for financial reporting
ADMS	Advanced Distribution Management System
WAM	Work and Asset Management system connects field employees with data in SAP

IT System O&M Expense – An analysis was conducted to determine the amount of IT System O&M expense that is related to non-asset based trading. First, for each IT system listed above, the amount of O&M expense assigned to NSPM was identified. Then the portion of the NSPM IT system O&M expense allocated to non-asset based trading was calculated based upon the Non-Asset Revenue Percent (a ratio of NSPM non-asset based trading revenue to NSPM Electric Utility revenue). Please see the top half of Attachment B for the IT system O&M expense assigned to non-asset based trading 2019 actual and the 2021-2023 MYRP forecast.

IT System Capital Revenue Requirements – An analysis was also conducted to determine the IT system capital revenue requirements associated with non-asset based trading. First, the rate base associated with the above listed IT systems was determined and the total 2021-2023 budget rate base and depreciation expense (capital costs) for the above listed IT systems was calculated. Second, the Non-Asset Revenue Percent was applied to the capital costs to calculate the IT system capital costs attributable to non-asset based trading. (See the bottom half of Attachment B.) Third, the resulting rate base and depreciation expense was used to calculate the 2021 test year and 2022-2023 plan years revenue requirements related to non-asset based trading. Attachment C shows the 2021-2023 IT systems capital revenue requirement calculation.

Conclusion

As shown in Attachment D, using the above described assumptions and methodology, each of the 2021 test year and 2022-2023 plan years includes between $2.1 million and $2.6 million in annual fully allocated costs attributed to non-asset based trading activity associated with the State of Minnesota electric retail jurisdiction.

Northern States Power Company **Attachment A**
Summary of Non-Asset Based Trading Costs

Fully Allocated Costs

O&M Expenses	**2017**	**2018**	**2019**	**Three Year Avg (2017-2019)**	**2020 Forecast**	**2021 Test Year**	**2022 Plan Year**	**2023 Plan Year**
Trading	$ 1,340,704	$ 772,826	$ 906,667	$ 1,006,732	$ 1,029,763	$ 1,066,642	$ 1,091,446	$ 1,117,146
Trading - SIP	$ 714,408	$ 854,215	$ 1,867,506	$ 1,145,376	$ 845,349	$ 1,053,968	$ 1,093,488	$ 1,392,936
Risk	$ 798,634	$ 271,989	$ 352,042	$ 474,222	$ 379,585	$ 351,709	$ 362,234	$ 372,239
Accounting	$ 226,820	$ 68,290	$ 76,619	$ 123,910	$ 10,602	$ 9,962	$ 10,261	$ 10,569
Indirect Labor Overhead	$ 940,845	$ 527,519	$ 536,541	$ 668,302	$ 572,756	$ 557,663	$ 559,721	$ 581,945
	$ 4,021,411	$ 2,494,839	$ 3,739,375	$ 3,046,209	$ 2,838,055	$ 3,039,944	$ 3,117,150	$ 3,474,835
Less Trading - SIP	$ (714,408)	$ (854,215)	$ (1,867,506)	$ (1,145,376)	$ (845,349)	$ (1,053,968)	$ (1,093,488)	$ (1,392,936)
Total Fully Allocated O&M Expenses	**$ 3,307,003**	**$ 1,640,624**	**$ 1,871,869**	$ 1,900,833	**$ 1,992,706**	**$ 1,985,976**	**$ 2,023,662**	**$ 2,081,899**

System Costs Related to Non-Asset Trading

Attachment B

	2019 Actual	2020	2021	2022	2023
Operating Revenues					
Retail	3,500,528,538	3,630,065,502	3,502,061,966	3,534,304,024	3,530,879,451
Interdepartmental	587,959	452,982	455,964	455,964	455,964
Other Operating Revenue - Non-Retail	985,263,387	659,264,752	734,667,535	756,515,210	762,108,807
Total Operating Revenues	4,486,379,883	4,289,783,236	4,237,185,466	4,291,275,198	4,293,444,223
NSPM Non-Asset Based Trading Revenue	111,151,707	62,194,602	192,749,923	192,749,923	192,749,923
Non-Asset Trading as Percent of Total		1.45%	4.55%	4.49%	4.49%

Actual and Fcst Depr Expense Year

Row Labels	**2019 Actual**	**Sum of Est 2020**	**Sum of Est 2021**	**Sum of Est 2022**	**Sum of Est 2023**
BO	134,936	0	0	0	0
CXT	1,063,875	1,063,875	971,862	615,027	381,504
Documentum	44,594	0	0	0	0
PCI MISO	0	0	0	0	0
SAP GL	2,016,874	2,016,874	2,016,874	2,016,874	2,016,874
WAM	7,877,902	7,877,902	7,877,902	7,877,902	7,877,902
SAP	673,448	673,448	599,934	440,522	433,418
COMMODITY XL	77,349	77,349	77,349	77,349	77,349
ADMS	31,239	31,239	31,239	31,239	31,239
Grand Total	**11,920,217**	**11,740,687**	**11,575,159**	**11,058,912**	**10,818,285**
IT Dep'n related to Non-Asset trading	**-**	**170,220**	**526,555**	**496,730**	**485,676**

Depr Reserves and Net Book Values by Year

Row Labels	**Sum of 2019 Depr Reserve**	**Sum of 2020 Depr Reserve**	**Sum of 2021 Depr Reserve**	**Sum of 2022 Depr Reserve**	**Sum of 2023 Depr Reserve**
BO	882,571	882,571	882,571	882,571	882,571
CXT	6,981,596	8,045,471	9,017,333	9,632,360	10,013,864
Documentum	2,520,332	2,520,332	2,520,332	2,520,332	2,520,332
PCI MISO	1,616,480	1,616,480	1,616,480	1,616,480	1,616,480
SAP GL	8,187,222	10,204,096	12,220,969	14,237,843	16,254,717
WAM	21,155,916	29,033,818	36,911,719	44,789,621	52,667,522
SAP	1,057,164	1,730,613	2,330,547	2,771,069	3,204,487
COMMODITY XL	77,349	154,698	232,047	309,396	386,745
ADMS	31,239	62,477	93,716	124,955	156,193
Grand Total	**42,509,869**	**54,250,555**	**65,825,715**	**76,884,627**	**87,702,912**
Undepreciated Balances related to Non-/	**-**	**786,541**	**2,994,417**	**3,453,404**	**3,937,335**

Northern States Power Company, a Minnesota corporation **Attachment C**

Non-Asset Based Trading Study Revenue Requirement

Rate Analysis	**2020**	**2021**	**2022**	**2023**
Rate Base				
EOY Net Plant	1,785,656	5,076,143	4,515,431	4,027,473
Depreciation	170,220	526,555	496,730	485,676
BOY Net Plant	1,955,876	5,602,698	5,012,161	4,513,149
Average Rate Base	**1,870,766**	**5,339,421**	**4,763,796**	**4,270,311**
Revenue Requirements				
Debt Return	42,100	120,100	107,200	96,100
Equity Return	90,400	257,900	230,100	206,300
Current Income Tax Requirement	36,500	104,000	92,800	83,200
Book Depreciation	170,220	526,555	496,730	485,676
Annual Deferred Tax	-	-	-	-
ITC Flow Thru	-	-	-	-
Tax Depreciation & Removal Expense	170,220	526,555	496,730	485,676
AFUDC Expenditure	-	-	-	-
Book Depreciation Cleared to Operating	-	-	-	-
Avoided Tax Interest	-	-	-	-
Property Tax	-	-	-	-
Total NSPM Revenue Requirements	**339,220**	**1,008,555**	**926,830**	**871,276**
MN Jurisdictional Demand Allocator	86.9972%	86.9972%	86.9972%	86.9972%
Minnesota Jurisdiction Revenue Requi	**295,112**	**877,415**	**806,316**	**757,986**

Last Authorized Cap Structure (2019 from 2016 MYRP)

Capital Structure	**Rate**	**Ratio**	**Weighted Cost**
Long Term Debt	**4.7500%**	**45.8100%**	**2.1800%**
Short Term Debt	**4.3100%**	**1.6900%**	**0.0700%**
Preferred Stock	**0.0000%**	**0.0000%**	**0.0000%**
Common Equity	**9.2000%**	**52.5000%**	**4.8300%**
Required Rate of Return			**7.0800%**
Tax Rate (MN)	28.7420%		

Northern States Power Company
State of Minnesota Electric Jurisdiction

Attachment D

Non-Asset Based Trading O&M Costs

	Total NSPM Electric		
	2021TY	**2022PY**	**2023PY**
O&M from cost study			
Allocation Method			
Fully Allocated O&M Expenses	1,985,976	2,023,662	2,081,899
Associated IT costs			
Allocation Method			
IT Depreciaton costs	526,555	496,730	485,676
Revenue requirement on IT in rate base	482,000	430,100	385,600
Total associated IT costs	1,008,555	926,830	871,276
Total NSPM Costs	**2,994,531**	**2,950,492**	**2,953,175**
EEnergy	86.5148%	86.5148%	86.5148%
EDemandProd	86.9972%	86.9972%	86.9972%

	Minnesota Electric Jurisdiction		
	2021TY	**2022PY**	**2023PY**
O&M from cost study			
Allocation Method			
Fully Allocated O&M Expenses	1,718,164	1,750,767	1,801,151
Associated IT costs			
Allocation Method			
IT Depreciaton costs	458,088	432,141	422,525
Revenue requirement on IT in rate base	419,327	374,175	335,461
Total associated IT costs	877,415	806,316	757,986
MN Electric Jurisdiction Adjustment	**2,595,578**	**2,557,083**	**2,559,136**

Northern States Power Company
Electric Utility - State of Minnesota
Production Tax Credits (PTCs)
2021-2023 MYRP
($000's)

MWH	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Annual - 2021
Grand Meadow													-
Nobles													-
Pleasant Valley	62,204	61,966	71,262	71,977	71,205	58,489	46,436	42,262	67,213	81,460	73,029	76,288	783,791
Border Winds	52,131	58,629	49,753	53,595	56,635	50,381	44,675	40,713	59,308	63,475	52,787	53,018	635,100
Courtenay	59,754	74,808	61,365	61,754	69,516	60,030	38,698	39,832	61,531	81,885	63,243	65,301	737,717
Blazing Star I	79,780	73,740	77,869	87,404	79,898	65,540	53,812	59,476	71,764	88,350	76,171	77,987	891,791
Foxtail	57,798	54,958	57,264	56,184	60,846	52,644	40,174	39,385	55,779	66,941	61,813	59,805	663,591
Lake Benton	31,553	37,109	39,370	43,717	39,967	33,546	27,909	30,405	36,571	44,550	34,916	33,955	433,568
Blazing Star II	78,113	71,465	76,317	84,425	77,229	63,997	53,112	58,031	69,981	86,167	74,419	75,663	868,919
Crowned Ridge	75,715	68,931	74,243	82,148	74,506	61,487	50,895	55,289	67,378	83,637	72,015	72,893	839,137
Jeffers	13,622	15,448	18,285	17,284	15,506	14,366	10,867	11,155	15,832	19,133	15,439	13,834	180,771
Community Wind North	7,756	8,205	8,468	10,181	8,998	7,391	5,938	6,326	8,081	10,576	8,959	7,743	98,622
Mower	32,439	29,545	31,156	32,008	32,649	26,760	19,957	18,282	28,143	36,325	32,694	34,420	354,378
Total	550,865	554,804	565,352	600,677	586,955	494,631	392,473	401,156	541,581	662,499	565,485	570,907	6,487,385
PTC Rate/Mwh	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00
PTCs													
Grand Meadow	-	-	-	-	-	-	-	-	-	-	-	-	-
Nobles	-	-	-	-	-	-	-	-	-	-	-	-	-
Pleasant Valley	1,555	1,549	1,782	1,799	1,780	1,462	1,161	1,057	1,680	2,037	1,826	1,907	19,595
Border Winds	1,303	1,466	1,244	1,340	1,416	1,260	1,117	1,018	1,483	1,587	1,320	1,326	15,878
Courtenay	1,494	1,870	1,534	1,544	1,738	1,501	968	996	1,538	2,047	1,581	1,633	18,443
Blazing Star I	1,995	1,844	1,947	2,185	1,998	1,639	1,345	1,487	1,794	2,209	1,904	1,950	22,295
Foxtail	1,445	1,374	1,432	1,405	1,521	1,316	1,004	985	1,395	1,674	1,545	1,495	16,590
Lake Benton	789	928	984	1,093	999	839	698	760	914	1,114	873	849	10,839
Blazing Star II	1,953	1,787	1,908	2,111	1,931	1,600	1,328	1,451	1,750	2,154	1,861	1,892	21,723
Crowned Ridge	1,893	1,723	1,856	2,054	1,863	1,537	1,272	1,382	1,685	2,091	1,800	1,822	20,979
Jeffers	341	386	457	432	388	359	272	279	396	478	386	346	4,520
Community Wind North	194	205	212	255	225	185	149	158	202	264	224	194	2,466
Mower	811	739	779	800	816	669	499	457	704	908	817	861	8,860
Total	$ 13,772	$ 13,870	$ 14,134	$ 15,017	$ 14,674	$ 12,366	$ 9,812	$ 10,029	$ 13,540	$ 16,563	$ 14,137	$ 14,273	$ 162,186

State of MN Energy Allocator	86.5148%
State of MN PTCs	**$ 140,315**
Revenue Requirement Conversion Factor	1.40335
State of MN Revenue Requirements	**$ (196,911)**
Interchange Agreement Energy Allocation	17.2463%
Interchange Agreement Revenue Offset	$ (33,960)
State of MN Revenue Requirements (Net of IA)	**$ (162,951)**

Northern States Power Company
Electric Utility - State of Minnesota
Production Tax Credits (PTCs)
2021-2023 MYRP
($000's)

MWH	Jan-22	Feb-22	Mar-22	Apr-22	May-22	Jun-22	Jul-22	Aug-22	Sep-22	Oct-22	Nov-22	Dec-22	Annual - 2022
Grand Meadow													-
Nobles													-
Pleasant Valley	62204	61966	71262	71977	71185	58489	46436	42262	67213	81460	73029	76288	783,771
Border Winds	52131	58629	49753	53595	56635	50381	44675	40713	59308	63475	52787	53018	635,100
Courtenay	59754	74808	61365	61754	69516	60030	38698	39832	61531	81885	63243	65301	737,717
Blazing Star I	79780	73740	77869	87404	79898	65540	53812	59476	71764	88350	76171	77987	891,791
Foxtail	57798	54958	57264	56184	60846	52644	40174	39385	55779	66941	61813	59805	663,591
Lake Benton	31553	37109	39370	43717	39967	33546	27909	30405	36571	44550	34916	33955	433,568
Blazing Star II	78113	71465	76317	84425	77229	63997	53112	58031	69981	86167	74419	75663	868,919
Crowned Ridge	75715	68931	74243	82148	74506	61487	50895	55289	67378	83637	72015	72893	839,137
Jeffers	13622	15448	18285	17284	15421	14366	10867	11155	15832	19133	15439	13834	180,686
Community Wind North	7756	8205	8468	10181	8948	7391	5938	6326	8081	10576	8959	7743	98,572
Mower	32439	29545	31156	32008	32649	26760	19957	18282	28143	36325	32694	34420	354,378
Total	550,865	554,804	565,352	600,677	586,800	494,631	392,473	401,156	541,581	662,499	565,485	570,907	6,487,230
PTC Rate/Mwh	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00
PTCs													
Grand Meadow	-	-	-	-	-	-	-	-	-	-	-	-	-
Nobles	-	-	-	-	-	-	-	-	-	-	-	-	-
Pleasant Valley	1,555	1,549	1,782	1,799	1,780	1,462	1,161	1,057	1,680	2,037	1,826	1,907	19,594
Border Winds	1,303	1,466	1,244	1,340	1,416	1,260	1,117	1,018	1,483	1,587	1,320	1,326	15,878
Courtenay	1,494	1,870	1,534	1,544	1,738	1,501	968	996	1,538	2,047	1,581	1,633	18,443
Blazing Star I	1,995	1,844	1,947	2,185	1,998	1,639	1,345	1,487	1,794	2,209	1,904	1,950	22,295
Foxtail	1,445	1,374	1,432	1,405	1,521	1,316	1,004	985	1,395	1,674	1,545	1,495	16,590
Lake Benton	789	928	984	1,093	999	839	698	760	914	1,114	873	849	10,839
Blazing Star II	1,953	1,787	1,908	2,111	1,931	1,600	1,328	1,451	1,750	2,154	1,861	1,892	21,723
Crowned Ridge	1,893	1,723	1,856	2,054	1,863	1,537	1,272	1,382	1,685	2,091	1,800	1,822	20,979
Jeffers	341	386	457	432	386	359	272	279	396	478	386	346	4,517
Community Wind North	194	205	212	255	224	185	149	158	202	264	224	194	2,464
Mower	811	739	779	800	816	669	499	457	704	908	817	861	8,860
Total	$ 13,772	$ 13,870	$ 14,134	$ 15,017	$ 14,670	$ 12,366	$ 9,812	$ 10,029	$ 13,540	$ 16,563	$ 14,137	$ 14,273	$ 162,182

State of MN Energy Allocator	86.5148%
State of MN PTCs	**$ 140,311**
Revenue Requirement Conversion Factor	1.40335
State of MN Revenue Requirements	**$ (196,906)**
Interchange Agreement Energy Allocation	17.2463%
Interchange Agreement Revenue Offset	$ (33,959)
State of MN Revenue Requirements (Net of IA)	**$ (162,947)**

($000's)

MWH	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Annual - 2023
Grand Meadow													-
Nobles													-
Pleasant Valley	62204	61966	71262	71977	71205	58489	46436	42262	67213	81460	73029	76288	783,791
Border Winds	52131	58629	49753	53595	56635	50381	44675	40713	59308	63475	52787	53018	635,100
Courtenay	59754	74808	61365	61754	69516	60030	38698	39832	61531	81885	63243	65301	737,717
Blazing Star I	79780	73740	77869	87404	79898	65540	53812	59476	71764	88350	76171	77987	891,791
Foxtail	57798	54958	57264	56184	60846	52644	40174	39385	55779	66941	61813	59805	663,591
Lake Benton	31553	37109	39370	43717	39967	33546	27909	30405	36571	44550	34916	33955	433,568
Blazing Star II	78113	71465	76317	84425	77229	63997	53112	58031	69981	86167	74419	75663	868,919
Crowned Ridge	75715	68931	74243	82148	74506	61487	50895	55289	67378	83637	72015	72893	839,137
Jeffers	13622	15448	18285	17284	15506	14366	10867	11155	15832	19133	15439	13834	180,771
Community Wind	7756	8205	8468	10181	8998	7391	5938	6326	8081	10576	8959	7743	98,622
Mower	32439	29545	31156	32008	32649	26760	19957	18282	28143	36325	32694	34420	354,378
Total	550,865	554,804	565,352	600,677	586,955	494,631	392,473	401,156	541,581	662,499	565,485	570,907	6,487,385
PTC Rate/Mwh	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00	$ 25.00
PTCs													
Grand Meadow	-	-	-	-	-	-	-	-	-	-	-	-	-
Nobles	-	-	-	-	-	-	-	-	-	-	-	-	-
Pleasant Valley	1,555	1,549	1,782	1,799	1,780	1,462	1,161	1,057	1,680	2,037	1,826	1,907	19,595
Border Winds	1,303	1,466	1,244	1,340	1,416	1,260	1,117	1,018	1,483	1,587	1,320	1,326	15,878
Courtenay	1,494	1,870	1,534	1,544	1,738	1,501	968	996	1,538	2,047	1,581	1,633	18,443
Blazing Star I	1,995	1,844	1,947	2,185	1,998	1,639	1,345	1,487	1,794	2,209	1,904	1,950	22,295
Foxtail	1,445	1,374	1,432	1,405	1,521	1,316	1,004	985	1,395	1,674	1,545	1,495	16,590
Lake Benton	789	928	984	1,093	999	839	698	760	914	1,114	873	849	10,839
Blazing Star II	1,953	1,787	1,908	2,111	1,931	1,600	1,328	1,451	1,750	2,154	1,861	1,892	21,723
Crowned Ridge	1,893	1,723	1,856	2,054	1,863	1,537	1,272	1,382	1,685	2,091	1,800	1,822	20,979
Jeffers	341	386	457	432	388	359	272	279	396	478	386	346	4,520
Community Wind	194	205	212	255	225	185	149	158	202	264	224	194	2,466
Mower	811	739	779	800	816	669	499	457	704	908	817	861	8,860
Total	$ 13,772	$ 13,870	$ 14,134	$ 15,017	$ 14,674	$ 12,366	$ 9,812	$ 10,029	$ 13,540	$ 16,563	$ 14,137	$ 14,273	$ 162,186

State of MN Energy Allocator	86.5148%
State of MN PTCs	**$ 140,315**
Revenue Requirement Conversion Factor	1.40335
State of MN Revenue Requirements	**$ (196,911)**
Interchange Agreement Energy Allocation	17.2463%
Interchange Agreement Revenue Offset	$ (33,960)
State of MN Revenue Requirements (Net of IA)	**$ (162,951)**

2021

	Days to Prorate	Prorate Factor	MN Jurisdiction Prorated Plant Deferred	MN Jurisdiction Prorated Plant Deferred	MN Jurisdiction NOL	MN Jurisdiction Prorated NOL	Monthly Expense	Prorated Monthly Expense
Annual Deferred Tax Expense			70,321,212		0		70,321,212	
January	335	91.78%	5,860,101	5,378,449	-	-	5,860,101	5,378,449
February	307	84.11%	5,860,101	4,928,907	-	-	5,860,101	4,928,907
March	276	75.62%	5,860,101	4,431,200	-	-	5,860,101	4,431,200
April	246	67.40%	5,860,101	3,949,548	-	-	5,860,101	3,949,548
May	215	58.90%	5,860,101	3,451,840	-	-	5,860,101	3,451,840
June	185	50.68%	5,860,101	2,970,188	-	-	5,860,101	2,970,188
July	154	42.19%	5,860,101	2,472,481	-	-	5,860,101	2,472,481
August	123	33.70%	5,860,101	1,974,774	-	-	5,860,101	1,974,774
September	93	25.48%	5,860,101	1,493,122	-	-	5,860,101	1,493,122
October	62	16.99%	5,860,101	995,414	-	-	5,860,101	995,414
November	32	8.77%	5,860,101	513,762	-	-	5,860,101	513,762
December	1	0.27%	5,860,101	16,055	-	-	5,860,101	16,055
							Total	**32,575,740**

	(Increase)/ decrease to accumulated deferred taxes
Increase/(Decrease) in Rate Base	
Pro-Rate Method	(32,575,740)
BOY/EOY Average	(35,160,606)
Accumulated Deferred Taxes Adjustment	2,584,866
ADIT Prorate for IRS Adjustment - Sch 10a	18,872,736
Adjustment	(16,287,870)

Capital Structure - Last Authorized	
Composite Tax Rate	28.74%
Weighted Cost of STD	0.07%
Weighted Cost of LTD	2.18%
Weighted Cost of Debt	2.25%
Weighted Cost of Equity	4.83%
Required Rate of Return	**7.08%**
Equity Return Tax RR	**1.95%**
RB Revenue Requirement Factor	9.0282%
Increase/(Decrease) in Revenue Requirement	
Annual Revenue Requirement Impact	233,367
ADIT Prorate for IRS Adjustment - Sch 11a	1,703,866
Adjustment	(1,470,499)

Capital Structure - Proposed	
Composite Tax Rate	28.74%
Weighted Cost of STD	0.01%
Weighted Cost of LTD	1.98%
Weighted Cost of Debt	1.99%
Weighted Cost of Equity	5.36%
Required Rate of Return	**7.35%**
Equity Return Tax RR	**2.16%**
RB Revenue Requirement Factor	9.5120%
Increase/(Decrease) in Revenue Requirement	
Annual Revenue Requirement Impact	245,872
ADIT Prorate for IRS Adjustment - Sch 12	1,795,168
Adjustment	(1,549,296)

2022

	Days to Prorate	Prorate Factor	MN Jurisdiction Prorated Plant Deferred	MN Jurisdiction Prorated Plant Deferred	MN Jurisdiction NOL	MN Jurisdiction Prorated NOL	Monthly Expense	Prorated Monthly Expense
Annual Deferred Tax Expense			12,102,865		0		12,102,865	
January	335	91.78%	1,008,572	925,676	-	-	1,008,572	925,676
February	307	84.11%	1,008,572	848,306	-	-	1,008,572	848,306
March	276	75.62%	1,008,572	762,646	-	-	1,008,572	762,646
April	246	67.40%	1,008,572	679,750	-	-	1,008,572	679,750
May	215	58.90%	1,008,572	594,090	-	-	1,008,572	594,090
June	185	50.68%	1,008,572	511,194	-	-	1,008,572	511,194
July	154	42.19%	1,008,572	425,535	-	-	1,008,572	425,535
August	123	33.70%	1,008,572	339,875	-	-	1,008,572	339,875
September	93	25.48%	1,008,572	256,979	-	-	1,008,572	256,979
October	62	16.99%	1,008,572	171,319	-	-	1,008,572	171,319
November	32	8.77%	1,008,572	88,423	-	-	1,008,572	88,423
December	1	0.27%	1,008,572	2,763	-	-	1,008,572	2,763
							Total	**5,606,555**

	(Increase)/ decrease to accumulated deferred taxes
Increase/(Decrease) in Rate Base	
Pro-Rate Method	(5,606,555)
BOY/EOY Average	(6,051,432)
Accumulated Deferred Taxes Adjustment	444,877
ADIT Prorate for IRS Adjustment - Sch 10b	3,248,155
Adjustment	(2,803,278)

Capital Structure - Last Authorized	
Composite Tax Rate	28.74%
Weighted Cost of STD	0.07%
Weighted Cost of LTD	2.18%
Weighted Cost of Debt	2.25%
Weighted Cost of Equity	4.83%
Required Rate of Return	**7.08%**
Equity Return Tax RR	**1.95%**
RB Revenue Requirement Factor	9.0282%
Increase/(Decrease) in Revenue Requirement	
Annual Revenue Requirement Impact	40,164
ADIT Prorate for IRS Adjustment - Sch 11b	293,249
Adjustment	(253,085)

Capital Structure - Proposed	
Composite Tax Rate	28.74%
Weighted Cost of STD	
Weighted Cost of LTD	1.98%
Weighted Cost of Debt	1.98%
Weighted Cost of Equity	5.36%
Required Rate of Return	**7.34%**
Equity Return Tax RR	**2.16%**
RB Revenue Requirement Factor	9.5020%
Increase/(Decrease) in Revenue Requirement	
Annual Revenue Requirement Impact	42,272
ADIT Prorate for IRS Adjustment - Sch 12	308,638
Adjustment	(266,366)

Plan Year Ending December 31, 2023

2023

	Days to Prorate	Prorate Factor	MN Jurisdiction Prorated Plant Deferred	MN Jurisdiction Prorated Plant Deferred	MN Jurisdiction NOL	MN Jurisdiction Prorated NOL	Monthly Expense	Prorated Monthly Expense
Annual Deferred Tax Expense			(14,451,559)		0		-14,451,559	
January	335	91.78%	(1,204,297)	(1,105,313)	-	-	(1,204,297)	(1,105,313)
February	307	84.11%	(1,204,297)	(1,012,929)	-	-	(1,204,297)	(1,012,929)
March	276	75.62%	(1,204,297)	(910,646)	-	-	(1,204,297)	(910,646)
April	246	67.40%	(1,204,297)	(811,663)	-	-	(1,204,297)	(811,663)
May	215	58.90%	(1,204,297)	(709,380)	-	-	(1,204,297)	(709,380)
June	185	50.68%	(1,204,297)	(610,397)	-	-	(1,204,297)	(610,397)
July	154	42.19%	(1,204,297)	(508,114)	-	-	(1,204,297)	(508,114)
August	123	33.70%	(1,204,297)	(405,831)	-	-	(1,204,297)	(405,831)
September	93	25.48%	(1,204,297)	(306,848)	-	-	(1,204,297)	(306,848)
October	62	16.99%	(1,204,297)	(204,565)	-	-	(1,204,297)	(204,565)
November	32	8.77%	(1,204,297)	(105,582)	-	-	(1,204,297)	(105,582)
December	1	0.27%	(1,204,297)	(3,299)	-	-	(1,204,297)	(3,299)
							Total	**(6,694,569)**

	(Increase)/ decrease to accumulated deferred taxes
Increase/(Decrease) in Rate Base	
Pro-Rate Method	6,694,569
BOY/EOY Average	7,225,780
Accumulated Deferred Taxes Adjustment	(531,210)
ADIT Prorate for IRS Adjustment - Sch 10c	(3,878,495)
Adjustment	3,347,285

Capital Structure - Last Authorized	
Composite Tax Rate	28.74%
Weighted Cost of STD	0.07%
Weighted Cost of LTD	2.18%
Weighted Cost of Debt	2.25%
Weighted Cost of Equity	4.83%
Required Rate of Return	**7.08%**
Equity Return Tax RR	**1.95%**
RB Revenue Requirement Factor	9.0282%
Increase/(Decrease) in Revenue Requirement	
Annual Revenue Requirement Impact	(47,959)
ADIT Prorate for IRS Adjustment - Sch 11c	(350,158)
Adjustment	302,199

Capital Structure - Proposed	
Composite Tax Rate	28.74%
Weighted Cost of STD	
Weighted Cost of LTD	1.97%
Weighted Cost of Debt	1.97%
Weighted Cost of Equity	5.36%
Required Rate of Return	**7.33%**
Equity Return Tax RR	**2.16%**
RB Revenue Requirement Factor	9.4920%
Increase/(Decrease) in Revenue Requirement	
Annual Revenue Requirement Impact	(50,422)
ADIT Prorate for IRS Adjustment - Sch 12	(368,145)
Adjustment	317,723

Prorate Adjustment Factor

Days	Month	Prorated Days	Prorate Factor
31	Jan	335	0.917808
28	Feb	307	0.841096
31	Mar	276	0.756164
30	Apr	246	0.673973
31	May	215	0.589041
30	Jun	185	0.506849
31	Jul	154	0.421918
31	Aug	123	0.336986
30	Sep	93	0.254795
31	Oct	62	0.169863
30	Nov	32	0.087671
31	Dec	1	0.002740
365			

Double Average Prorate Factor	0.231621
BOY/EOY Average Factor	0.500000
Prorate Adjustment Factor	0.268379

Removing Double Average from Prorate Factor

Average Prorate Factor	0.463242
BOY/EOY Average Factor	0.500000
Prorate Adjustment Factor	0.036758

Northern States Power Company
Electric Utility - State of Minnesota
Net Operating Loss (NOL)
Test Year Ending December 31, 2021
($000's)

Docket No. E002/GR-20-723
Exhibit___(BCH-1) Schedule 20
2021-2023 MYRP

Impact of Unused/(Utilized) Tax Deductions on Rate Base	2019 Annual Report EOY Balances	2020 Bridge Annual Activity Amounts	2020 Bridge EOY Balances	2021 Test Year Annual Activity Amounts	2021 Test Year EOY Balances	2022 Plan Year Annual Activity Amounts	2022 Plan Year EOY Balances	2023 Plan Year Annual Activity Amounts	2023 Plan Year EOY Balances
1. Unused/(Utilized) Deductions	0	0	0	0	0	0	0	0	0
2. Deferred Tax Effect of Unused/(Utilized) Deductions	0	0	0	0	0	0	0	0	0
3. Unused/(Utilized) Credits State	0	0	0	0	0	0	0	0	0
4. Unused/(Utilized) Credits Federal	303,056	57,682	360,738	155,847	516,584	161,680	678,265	135,490	813,754
5. Accumulated Deferred Income Taxes (ADIT)	**303,056**	**57,682**	**360,738**	**155,847**	**516,584**	**161,680**	**678,265**	**135,490**	**813,754**

Impact of Unused/(Utilized) Tax Deductions on Revenue Requirements	2020 Bridge Year Utilization Adjustment	2021 Test Year Utilization Adjustment	2022 Plan Year Utilization Adjustment	2023 Plan Year Utilization Adjustment	Comment
6. Deferred Tax Asset BOY	0	0	0	0	Zero since compliance filing is based on current year activity
7. Deferred Tax Asset EOY	57,682	155,847	161,680	135,490	From Unused/(Utilized) columns on Line 4
8. Average Rate Base	28,841	77,923	80,840	67,745	(BOY + EOY)/2
9. Return Requirement	2,140	5,727	5,934	4,966	Rate Base * Req Rate of Return
10. RR Tax on Equity Return	624	1,685	1,748	1,465	(T/(1-T))*RB*Equity Return
11. Rate Base Revenue Requirement	2,764	7,412	7,681	6,430	Line 9 + Line 10
12. Deferred Tax	(57,682)	(155,847)	(161,680)	(135,490)	From Unused/(Utilized) columns on Line 5
13. Current Tax Rev Req [1]	57,682	155,847	161,680	135,490	From Line 19
14. Annual Revenue Requirement Increase (Reduction)	**2,764**	**7,412**	**7,681**	**6,430**	Line 10+11+12
[1] *Current Income Tax Rev Req Calculation*					
15. Utilized Deductions	-	-	-	-	Unused Annual Deductions
16. Deferred Taxes	(57,682)	(155,847)	(161,680)	(135,490)	Line 12
17. Unused State Tax Credits	-	-	-	-	From Unused/(Utilized) columns on Line 3
18. Unused Federal Tax Credits	57,682	155,847	161,680	135,490	From Unused/(Utilized) columns on Line 4
19. Current Income Tax Revenue Requirement	57,682	155,847	161,680	135,490	(T/(1-T))*(-Line 15+.79xLine16+Line17)+.79xLine 16+Line 17

Validation Section	2020	2021	2022	2023
Total Annual Activity Revenue Requirements	2,764	7,412	7,681	6,430
RR on beg balance	29,039	34,313	49,086	64,381
Sec 199 Manufacture Production Deduction - Fed	-	-	-	-
Section 199 Revenue Requirement	-	-	-	-
Total NOL & Sec 199 for validation	31,802	41,725	56,767	70,811
RIS COSS	31,802	41,725	56,767	70,811
Difference	(0)	-	-	-
Total Average Rate Base	28,841	135,605	294,369	442,954

Weighted Cost of Capital	2020	2021	2022	2023
Active Rates and Ratios Version	Proposed	Proposed	Proposed	Proposed
Cost of Short Term Debt	2.83%	1.00%	2.82%	2.21%
Cost of Long Term Debt	4.33%	4.22%	4.19%	4.17%
Cost of Common Equity	10.20%	10.20%	10.20%	10.20%
Ratio of Short Term Debt	0.23%	0.54%	0.16%	0.20%
Ratio of Long Term Debt	47.27%	46.96%	47.34%	47.30%
Ratio of Common Equity	52.50%	52.50%	52.50%	52.50%
Weighted Cost of STD	0.01%	0.01%		
Weighted Cost of LTD	2.05%	1.98%	1.98%	1.97%
Weighted Cost of Debt	2.06%	1.99%	1.98%	1.97%
Weighted Cost of Equity	5.36%	5.36%	5.36%	5.36%
Required Rate of Return	**7.42%**	**7.35%**	**7.34%**	**7.33%**
Corp Composite Tax Rate	28.11%	28.11%	28.11%	28.11%
MN Composite Tax Rate	28.74%	28.74%	28.74%	28.74%

MYRP Forecast Fuel Reconciliation

Category	2021 Test Year	2022 Plan Year	2023 Plan Year	Comments
Fuel and Purchased Power	$ 1,203,609	$ 1,203,463	$ 1,203,944	BCH-1, Sch. 11a-11c, column 5, row 10
Costs Not Recoverable in Fuel Clause:				
Less Fuel Handling O&M Expenses	$ (13,942)	$ (13,879)	$ (14,443)	
Less Non-Asset Based Trading Expenses	$ (153,417)	$ (153,417)	$ (153,417)	
Less Off-System Sales Net of Interchange	$ (117,919)	$ (117,919)	$ (117,919)	
Less Windsource Fuel Costs	$ (6,004)	$ (6,004)	$ (6,004)	
Less Renewable*Connect Costs	$ (6,286)	$ (6,286)	$ (6,286)	
Subtotal	$ (297,567)	$ (297,504)	$ (298,069)	
Interchange Agreement Impacts				
Less Minnesota Fuel Costs Offset by Interchange Revenue	$ (156,298)	$ (156,215)	$ (156,132)	
Total Minnesota Fuel Costs included in Cost of Service	$ 749,743	$ 749,743	$ 749,743	
Minnesota Fuel Costs recovered through FCA	$ 749,743	$ 749,743	$ 749,743	FCA revenues included in retail revenue
Difference in Fuel Costs and Fuel Revenue	$ -	$ -	$ -	

		2021 Test Year	2022 Rate Plan Year	2023 Rate Plan Year
Base Rates				
TCR Rider Projects				
CapX2020 - Brookings*	Base Rates	X	X	X
CapX2020 - Fargo*	Base Rates	X	X	X
CAPX2020 - La Crosse Local*	Base Rates	X	X	X
CAPX2020 - La Crosse MISO*	Base Rates	X	X	X
CAPX2020 - La Crosse MISO - WI*	Base Rates	X	X	X
Big Stone - Brookings*	Base Rates	X	X	X
La Crosse - Madison*	Base Rates	X	X	X
MISO RECB Sch 26 and 26A net revenues**	Rider Project	✓	✓	✓
AGIS - ADMS**	Rider Project	✓	✓	✓
AGIS - AMI**	Rider Project	✓	✓	✓
AGIS - FAN**	Rider Project	✓	✓	✓
AGIS - LoadSeer**	Rider Project	✓	✓	✓
AGIS - TOU Pilot**	Rider Project	✓	✓	✓
Huntley Wilmarth**	Rider Project	✓	✓	✓
Interim rates - No TCR Projects in 2021/2022				
Base Rates				
RES Rider Projects				
Courtenay Wind Farm*	Base Rates	X	X	X
Foxtail Wind Farm*	Base Rates	X	X	X
Blazing Star I Wind Farm*	Base Rates	X	X	X
Lake Benton Wind Farm*	Base Rates	X	X	X
Blazing Star II Wind Farm*	Base Rates	X	X	X
Crowned Ridge Wind Farm*	Base Rates	X	X	X
Jeffers Wind Farm*	Base Rates	X	X	X
Community Wind North*	Base Rates	X	X	X
Mower Wind Farm*	Base Rates	X	X	X
Freeborn Wind Farm**	Rider Project	✓	✓	✓
Dakota Range Wind Farm**	Rider Project	✓	✓	✓
Interim rates - No RES Projects in 2021/2022				

* Included in 2021 to 2023 Plan Years with 2021 and 2022 Interim rate adjustments to exclude from Interim rates; to be recovered in base rates and removed from the TCR Rider at conclusion of the case.

** Removed from 2021 to 2023 Plan Year revenue requirement calculations (revenues and expenses), projects continue recovery in the RES and TCR Riders. after the conclusion of the rate case.

**** The Rider Roll-In Timeline is based on the timeline identified in the Direct Testimony of Mr. Halama

Procedural Key Milestones from Nov 2020 to June 2022 (tentative subject to change based on procedural schedule)

- November, 2020: 2021-2023 Rate case filed
- Week of October 28, 2020: 2021 RES/TCR Rider Supplements filed
- January 1, 2021: 2021 Interim Rates and 2021 RES/TCR rate effective
- January 1, 2022: 2022 Interim Rates
- March 1, 2022: MPUC Multi-Year Rate Plan Order
- April 1, 2022: Final Rates Compliance Filing